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July 24, 2020

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 374 – In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Attached for rebuttal filing are the following Exhibits:

Exhibit 1800 to 1802 Fox (Exh 1800 Confidential page: 4)

Exhibit 1900 to 1912 Muldoon-Enright-Dlouhy (Exh 1900 Confidential pages: 28, 61, 62, 67 & 68),
Exhibit 1901 to Exhibit 1912 (Confidential exhibits: 1902 electronic and 1912)

Exhibit 2000 to 2002 Storm (Exh 2000 Confidential pages: 3, 19, 29, 30, 35)

Exhibit 2100 to 2108 Hanhan-Rashid-Muldoon
(Exh 2100 Confidential pages: 1, 2, 15-17, 22-31, 35-44, 49, 50 and 54-47)
Exhibit 2101 and Confidential Exhibits 2102 to Confidential Exhibit 2108

Exhibit 2200 Anderson

Exhibit 2300 to 2303 Soldavini
(Exh 2300 Highly Confidential pages: 69-70);
(Exh 2300 Confidential pages: 1, 4, 11-12, 25, 27-29, 30-33, 35-36, 44, 49, 50, 52-58, 63-64, 68, 73-74, 76-78, and 80-84)
Exhibit 2301 and 2 electronic confidential spreadsheet
Exhibit 2302 and page 9-10 are confidential and 2 electronic confidential spreadsheet
Exhibit 2303 confidential

Exhibit 2400 to 2403 Gibbens (Exh 2400 Confidential pages are: 19 to 23)
Exhibit 2401, Exhibit 2402 has electronic confidential spreadsheet and Confidential Exhibit 2403

CERTIFICATE OF SERVICE

UE 374

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 24th day of July, 2020 at Salem, Oregon

Kay Barnes

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CASE: UE 374
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1800

Rebuttal Testimony

REDACTED
July 24, 2020

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is John L. Fox. I am a Senior Financial Analyst employed in the
3 Energy Rates, Finance, and Audit Division of the Public Utility Commission of
4 Oregon (OPUC). My business address is 201 High Street SE, Suite 100,
5 Salem, Oregon 97301.

6 **Q. Please describe your educational background and work experience.**

7 A. My updated witness qualification statement is included in the errata filing which
8 occurred June 24, 2020, to Staff/1001.

9 **Q. What is the purpose of your testimony?**

10 A. The purpose of my testimony is to present the changes in revenue
11 requirement associated with Staff's rebuttal position and to respond specifically
12 to the following portions of the Company's reply testimony:

13 - PAC/2000, Wilding
14 - II.C. Cholla Unit 4 and TCJA Tax Benefits Proposal
15 - II.D. Capital Investments
16 - PAC/2100, Kobliha
17 - V. Pension
18 - PAC/3100, McCoy
19 - III. B. Incremental O&M Expense
20 - III. D. Tax

21 **Q. Did you prepare an exhibit for this docket?**

22 A. Yes, I prepared the following exhibits:

23 - Exhibit 1801, EDIT return example calculations.

- Exhibit 1802, Staff Data Requests regarding AMI

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Summary of Revenue Requirement 3
Issue 2, Incremental Financial Benefits of AMI 8
Issue 3, Oregon Corporate Activity Tax (OCAT) 10
Issue 4, Pensions 13
Issue 5, Gross Up of TCJA Benefits 20
Issue 6, Other Recommendations 26

ISSUE 1, SUMMARY OF REVENUE REQUIREMENT

Q. First, regarding the Company's general concerns about Staff's ongoing investigation[1] and the volume of discovery[2] propounded on the Company, how do you respond?

A. The circumstances underlying delays in Staff's investigation will be further elaborated by each rebuttal witness.

Regarding the volume of discovery, Staff notes that the number of data request is roughly proportionate to the size of the Company's filing[3]:

	UE 246	UE 263	UE 374
Initial Filing (pages)	1,327	1,047	2,525
Staff Data Requests	862	677	1,877
Ratio	1.54	1.55	1.35

The current filing is 141% longer than the prior rate case and Staff issued 177% more data requests. In Staff's view, the increase in discovery is entirely reasonable given that a longer filing is necessarily a more complex one and the fact that seven years have elapsed since the last rate case. Further, as was discussed in Staff's Opening Testimony by various witnesses, some of the Company's initial responses necessitated follow-up, often in the form of additional data requests.

Q. Please summarize Staff's updated adjustments to the revenue requirement in this case.

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[1] PAC/2000, Wilding/12.
[2] PAC/2000, Wilding/14.
[3] *Id.* Data request counts per the Company's reply testimony.

A. Staff proposes a revenue requirement change of ($7.525) million which reflects a decrease of $14.725 million from Staff's opening testimony recommendation of $7.2 million. Staff's proposed adjustments are itemized in the following table (Table A).

UE 374 PacifiCorp
STAFF ISSUE SUMMARY
12 Mos. Ended December 31, 2021
($000)

Incremental Revenue Requirement on the Company's Filed General Rate Case Results							**$79,654**
TAM-Related Revenue Sensitive Costs							**($1,660)**
Combined General Rate Case and TAM-Related Revenue Requirement							**$77,993**
Staff Witness	**Testimony**	**Issue**	**Proposed Staff Adjustments**	**Rev.**	**Exp.**	**RB**	**Rev. Req. Effect**
Fox	1800	1	TAM Revenue Sensitive				($64)
Fox	1800	1	Interest Synchronization				(2,316)
Fox	1800	2	AMI		(8,642)		(8,923)
Fox	1800	3	Oregon Corporate Activity Tax		5,300		5,733
Fox	1800	4	Pension		(2,223)		(2,295)
Fox	1800	5	TCJA Deferred Balance (Sch 195 chg. - No Base Rate impact)				
Fox	1800	6.1	Misc. Deferred Credit			28	2
Fox	1800	6.2	Fish Passage Project - ILR 4.1.9 Future Fish Passage		(57)	(2,062)	(239)
Fox	1800	6.3	CUWCD Project		20	(42)	17
Muldoon	1900		Cost of Capital (Capital Structure, ROE, LTD)				(42,383)
Storm	2000	1	Wind Farm Equipment			0	0
Storm	2000	4	OPEB Plan		0		0
Hanhan	2100	1	Transmission				
Soldavini	2300	1-4	Emissions Control Retrofit Investments				
Soldavini	2300	5	Other Revenue				0
Soldavini	2300	6	Reliability Coordinator Fees		(576)		(594)
Soldavini	2300	7	Affiliate Allocations		(72)		(74)
Cohen	400	5	Customer Accounts		(1,448)		(1,496)
Cohen	2500	1 & 2	Wages & Salaries		(5,922)	(3,390)	(6,409)
Cohen	2500	3	Advertising		(958)		(989)
Fjeldheim	2600	1.1	Low Claims Bonus				
Fjeldheim	2600	1.2	Insurance Premiums		(1,088)		(1,123)
Fjeldheim	2600	2.1	OPUC Fee		(669)		(691)
Fjeldheim	2600	2.2	Franchise Fees		(175)		(181)
Fjeldheim	2600	2.3	ODOE Fee		(26)		(27)
Fjeldheim	2600	3.2	KHSA-KRRC Duplicate entries		0		0
Fjeldheim	2600	4.1	Cyber Security		(221)	(691)	(288)
Moore	2700	1	Vegetation Mgmnt & Wildfire Mitigation		(6,645)		(6,861)
Rossow	2800	1	Memberships, Dues		(19)		(20)
Rossow	2000	1	Meals & Entertainment		(577)		(596)
Beitzel	3000	1	O&M Accounts 560-598		(2,720)		(2,808)
Beitzel	3000	1	Administrative & General Accounts		(896)		(925)
							0
Total Staff-Proposed Adjustments (Base Rates):							**($85,518)**
Staff-Calculated Revenue Requirements Change (Base Rates):							**($7,525)**

1 **Q. Please explain the TAM related revenue sensitive cost adjustment.**

2 A. Revenue sensitive costs include Uncollectibles, Franchise Fees, Resource
3 Supplier Fees, and OPUC Fees. TAM-Related Revenue Sensitive Costs
4 may only be adjusted during a general rate case. For TAM dockets that
5 occur between rate cases the revenue sensitive costs do not change.

6 In its initial filing, PacifiCorp had forecasted the TAM price change to be
7 a decrease of $49.211 million [4] and Staff confirmed the associated
8 adjustment for TAM revenue sensitive items to be ($1.660) million.[5]

9 The TAM revenue sensitive adjustment in this rebuttal filing is $64
10 thousand which reflects the incremental adjustment associated with the
11 revised TAM price change to $47.370 million and changes to the revenue
12 sensitive factors as further discussed in the testimony of Staff witness Brian
13 Fjeldheim (Staff Exhibit 2600).

14 **Q. Please explain the interest synchronization adjustment.**

15 A. According to long-standing Commission policy, for ratemaking purposes, Staff
16 routinely synchronizes interest expense to reflect changes in the regulated
17 utility's cost of capital as initially filed in a general rate case. Accordingly, the
18 interest synchronization adjustment depends on proposed adjustments to cost
19 of capital (CoC) in this docket. Because interest expense on long-term debt is
20 tax deductible, the proposed cost of long-term debt impacts income tax
21 expense for ratemaking purposes.

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[4] Exhibit PAC/1301, McCoy/3 at 2, col (2).
[5] Staff/100, Gardner/7.

1 In opening testimony, Staff explained the methodology and calculated an
2 interest synchronization adjustment of $1.397 million.[6]
3 The interest synchronization adjustment in this rebuttal filing increased to
4 $2.316 million due to Staff's revised capital structure proposal as further
5 discussed in the joint testimony of Staff witnesses Matt Muldoon, Moya Enright,
6 and Curtis Dlouhy (Staff Exhibit 1900).
7 **Q. Do you have any general concerns with the Company's approach to**
8 **setting rates in this case?**
9 A. Yes, and I would say there is a sustained erosion of traditional ratemaking
10 principles.
11 Under traditional ratemaking, utilities have the opportunity to earn their
12 authorized rate of return in between general rate revisions but also bear the
13 risk of actual revenue and expenses varying from the most recent rate case
14 (a.k.a regulatory lag). Oregon provided for limited adjustments between rate
15 cases for statutory deferrals and various other adjustments (e.g. annual power
16 cost, etc.). As the number and scope of these adjustments increase,
17 Company's tend to enjoy dollar for dollar recovery of additional costs while the
18 benefit of reduced costs are absorbed in regulatory lag. Taken as a whole, the
19 Company's position on the issues below continues this pattern by attempting to
20 achieve dollar for dollar recovery of any additional expense while retaining the
21 benefit of lower costs as part of regulatory lag.

[6] Staff/100, Gardner/8

1 As these concerns relate to the issues in my case, the incremental financial
2 benefits of AMI are a known and measurable change that should have been
3 included as an adjustment in favor of ratepayers in the Company's initial filing.
4 Related to the OCAT, the Company seeks to continue the currently approved
5 deferral and automatic adjustment clause until the Company's next rate case
6 thereby achieving dollar for dollar recovery, whereas Staff continues to propose
7 that the OCAT be included in base rates.
8 Regarding pensions, the Company seeks to increase the revenue
9 requirement for estimated settlement costs above and beyond the
10 Commission's longstanding policy of basing rate recovery on net periodic
11 benefit cost (a.k.a FAS 87). As further discussed below, the Company's Reply
12 Testimony positions seek to maximize the benefit of regulatory lag while
13 achieving dollar for dollar recovery for a portion of pension costs.
14 And finally, the Company's proposed amount of remaining EDIT to be
15 returned Schedule 195 is calculated in a manner that unfairly reduces the
16 amount of Tax Cut and Jobs Act (TCJA) benefits being returned to customers.
17

1 **ISSUE 2, INCREMENTAL FINANCIAL BENEFITS OF AMI**

2 **Q. Please summarize the Company's Reply Testimony related to**
3 **incremental financial benefits of AMI.**

4 A. The Company agrees with Staff's adjustment in concept, which is $13 million[7];
5 however, the Company proposes the following changes to Staff's adjustment:

6 - Disregard the capital expenditure component of $1.2 million.
7 - Reduce the remaining portion of Staff's adjustment from $11.8 million to
8 $6.5 million.[8]

9 **Q. Please discuss the capital expenditure component.**

10 A. The Company states that the $1.2 million is avoided cost and is not included in
11 the revenue requirement.[9]

12 Staff notes that the entire AMI savings of $12.962 million, or any portion
13 thereof, was not explicitly reflected in the Company's Initial Filing. Staff also
14 notes that the Company's response to Staff Data Request 389 indicates that
15 the capital savings are annual and begin in 2020.[10] Since the O&M costs were
16 not adjusted, Staff presumes the capital costs were not removed from the rate
17 base projections either.

18 **Q. Please discuss the Company's proposed O&M adjustment.**

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[7] Staff/1000, Fox/8
[8] PAC/3100, McCoy/26
[9] *Id.*
[10] Staff/1802, Fox/1.

1 A. The Company's response to Staff Data Request 592 states that the Company
2 estimates it "achieved approximately 45 percent of its net operational 2020
3 benefits in the base year."[11] No further analysis or details were provided.
4 **Q. What is Staff's recommendation?**
5 A. The nature of the Company's discovery responses would indicate there
6 remains a level of uncertainty regarding how the savings should be split
7 between the base and test years. Accordingly, Staff recommends that an
8 amount that is more conservative in ratepayers' favor, 2/3 of the total or $8.7
9 million, be removed from the revenue requirement in this case rather than the
10 Company's figure of $6.5 million. Staff finds this to be appropriate because it is
11 not apparent how ratepayers are receiving an ongoing benefit for the future
12 annual reduction in incremental capital costs.
13

[11] Staff/1802, Fox/4.

ISSUE 3, OREGON CORPORATE ACTIVITY TAX (OCAT)

Q. Please summarize the Company's Reply Testimony related to the Oregon Corporate Activity Tax.

A. The Company states that significant uncertainty remains regarding the OCAT, that Staff has inexplicably changed its position relative to Commission Order No. 20-028, and recommends continuation of the current balancing account and automatic adjustment clause (AAC) until the Company's next general rate case (GRC).[12] The Company also requests that, if the Commission were to include the OCAT is base rates in this case that "the Company requests the ability to continue to defer and recover or return any incremental differences."[13]

Q. Please provide the relevant background on the OCAT, including a discussion of the Commission's decision in Order No. 20-028.

A. Order No. 20-028 included a succinct statement of Staff's positions regarding inclusion in base rates.

> In Staff's view, the new OCAT is fundamentally different from the MCBIT in that it is a statewide tax that does not need to be isolated and recovered from a specific subset of the Company's customer base as is required for the MCBIT under OAR 860-022-0045. Also, as noted above, the tax is in addition to any other taxes or fees imposed by the State of Oregon. In other words, from a ratemaking perspective, the OCAT is simply an increase in the overall state tax burden. Accordingly, Staff's position is the OCAT ought to be estimated and rolled into base rates as soon as practicable.[14]

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[12] PAC/3100, McCoy/31.
[13] PAC/3100, McCoy/32.
[14] See In the Matters of PACIFICORP, dba PACIFIC POWER, Application for Deferral of Costs and Revenues Related to the Payment and Collection of Oregon's Corporate Activity Tax (OCAT).(UM 2036), and Application for Approval of Advice No. 19-015 - Schedule 104, Oregon Corporate Activity Tax Recovery Adjustment (UE 367), Order No. 20-028, Jan 29, 2020 at 4.

Regarding the $5.2 million annual estimate, the Order also reflects the Company's characterization at the time (emphasis added),

> Because the law is new and complex, PacifiCorp's precise OCAT expenses are not yet clear. As a result, Schedule 104 is based on PacifiCorp's high-level forecast of its estimated OCAT expense. ***PacifiCorp believes that the proposed tariff rate will cover the necessary tax expenses without significant over- or under-collections.*** However, given the uncertainty associated with ongoing difference between the company's OCAT expense collected under Schedule 104 and the company's actual OCAT expense. These amounts will be charged or credited to customers through an annual update to the Schedule 104 rate.[15]

And also,

> Staff, CUB, and AWEC expressed a willingness to support the proposed rate recovery mechanism with the understanding the OCAT will be rolled into base rates as soon as practicable and a willingness to work in good faith to make that determination.[16]

Accordingly, Staff is somewhat perplexed as to why the Company would assert that Staff has inexplicably changed its position. In Staff's view, bringing the issue into the rate case is a good faith effort to determine if inclusion in rates is practical at this time.

Q. Does Staff consider the amount of the OCAT to be reasonably estimable at this time?

A. Yes. Staff finds that there is a sufficient basis to estimate the OCAT going forward, as the Department of Revenue has issued guidance subsequent to the Commission's approval of the Company's initial deferral and AAC. The

[15] *Id.*
[16] *Id* at 5.

1 Company has provided no credible basis to exclude these amounts from base
2 rates in this case.
3 At a minimum, the Company should inform the record in surrebuttal testimony
4 and quantify the range of uncertainty. Staff notes that the Company is required
5 to remit OCAT payments on an estimated basis quarterly.
6 **Q. Are there other reasons Staff favors including the OCAT in base rates**
7 **at this time?**
8 A. Yes, there are several.
9 First, as discussed in Issue 1 above, Staff generally opposes ongoing dollar
10 for dollar recovery because it erodes traditional ratemaking. Likewise, Staff
11 opposes ongoing deferral of any incremental differences for the same reason.
12 Second, it has been seven years since the Company's last rate case, in the
13 event a similar interval ensues before the next GRC, Staff believes potentially
14 continuing dollar for dollar recovery for that length of time is unreasonable and
15 not in the best interests of ratepayers, when balanced with the fact that there is
16 now a sufficient basis to calculate the OCAT for inclusion in base rates.
17 **Q. What is Staff's recommendation?**
18 A. Staff continues to recommend the inclusion of the OCAT in base rates in this
19 case, at the $5.2 million level.
20 Staff recommends the Commission reject the Company's request to defer and
21 recover or return any incremental differences.
22

ISSUE 4, PENSIONS

Q. Please summarize the Company's Reply Testimony related to pensions.

A. The Company continues its effort to include the cost of settlements and curtailments in the Commission's definition of pension cost for regulatory purposes and also argues the excluding the cost of settlements from the revenue requirement in this case is not fair, just, and reasonable.[17] The Company also states that is "willing to accept" a deferral mechanism if the proposed settlement costs are not included in base rates and/or a balancing account for all pension costs on a prospective basis.[18]

Q. Please discuss the Company's assertions regarding how pension costs are defined.

A. The Company states the following:

> In Order No. 20-004, the Commission acknowledged that ASC 715-30 superseded the Financial Accounting Standards Board's FAS references, including FAS 87, and that "ASC" and "FAS" were to be used interchangeably.[19]

And also,

> Order No. 20-004 acknowledges that pension expense encompasses settlement losses and does not suggest that they 1 are not an appropriate pension cost to be recovered under the Commission's long standing practices.[20]

[17] PAC/2100, Kobliha/12
[18] PAC/2100, Kobliha/15
[19] PAC/2100, Kobliha/12.
[20] *Id.*

Q. Does Staff agree with PacifiCorp's assertions?

A. No. The Company appears to be relying on a footnote[21] in Order No. 20-004 that states the codification (ASC) superseded the previous separate individual accounting pronouncements (FAS) at authoritative literature. Nowhere in the Order did the Commission state that its regulatory definition of pension costs for cost recovery purposes is now inclusive of both FAS 87 and FAS 88. In fact, later in the Order the Commission referred directly to its previous definition:

> The Commission has had a long and well-established process for addressing pension costs in setting utility rates. We recently described that process in detail and reaffirmed the use of the FAS 87 methodology and how it has applied in the utility regulatory context in Oregon.[22] In that order, we found that there had been "no systemic change to the dynamics of FAS 87 pension expense that justifies a change to our current pension cost policy.[23]

Q. How are pension costs defined per the Commission's investigation into the treatment of pension costs in utility rates, as set forth in Order No. 15-226?

A. The following is excerpted directly from the Order No. 15-226.[24]

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[21] See *In the Matter of PACIFICORP, dba PACIFIC POWER, Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans*, Docket No. UM 1992, Order No. 20-004, Jan 8, 2020, at 2.
[22] Order No. 20-004 at 2; See also, *In the Matter of Public Utility Commission of Oregon Investigation into Treatment of Pension Costs in Utility Rates*, Docket No. UM 1633, Order No. 15-226 at 2-3 (Aug 3, 2015).
[23] *Id.* at 8.
[24] *Id.* at 2-3.

A. Accounting Requirements

Since 1987, employers are required to use FAS 87 accounting standards for financial reporting of pension costs. FAS 87 requires employers to recognize the cost of their pension plans on an accrual rather than a cash basis. In other words, pension cost is recognized over the period during which benefits are earned, or "accrued"—that is, during the working years of the employees that will receive the pension benefits during retirement.

Because FAS 87 expense is based on an accrual, not cash basis, the amount of pension costs recorded is generally different than the actual amount of annual contributions made. Over the life of the plan, however, total contributions are expected to equal total FAS 87 expense (as well as FAS 88 expense related to pension plan termination).

The FAS 87 expense, which can be positive or negative, is calculated based on four components:

- Service cost – The value of the benefits earned, or accrued during the current year based on the applicable benefit formula for each participant.
- Interest cost – The interest on the pension plan liability (projected benefit obligation) for the year. This amount increases pension cost and represents the time value of money on the benefit obligation.

- Expected return on assets – The expected return on assets for the year, which if positive will reduce pension cost. The difference between the actual return on assets and the expected return on assets represents an actuarial gain or loss that will be recognized in future pension cost.
- Amortizations of unrecognized costs – The change in liability due to plan changes, changes in actuarial assumptions used to value plan liabilities, differences between past differences between expected and actual asset returns, and other unrecognized gains and losses.

When the pension fund trust is producing significant investment gains, the FAS 87 expense can be negative, signaling that the trust is in good financial health. When the pension fund investments lose value, the FAS 87 turns positive, signaling a need for increased contributions.

Staff notes this is the same material referenced by the Commission itself in the preceding quote.

Q. What is Staff's understanding of the Commission's Order?

1 A. The Commission, at the time, clearly viewed FAS 87 and FAS 88 separately as
2 they state contributions over the life of the plan are the sum of the two.
3 Immediately following, the Commission delineates the four components of FAS
4 87 expense. This is also known as net periodic benefit cost.
5 **Q. Is it Staff's position that the Commission's definition of pension cost**
6 **excludes FAS 88?**
7 A. Yes.
8 **Q. Has Staff previously provided testimony to the Commission regarding**
9 **this particular point?**
10 A. Yes.[25]
11 **Q. Do you agree with the Company's assertion that it is not fair, just, and**
12 **reasonable to exclude settlement costs from base rates?**
13 A. No. Staff would assert the opposite. Including settlement cost in rates in not
14 fair, just, nor reasonable.
15 **Q. Why is excluding these costs from rates fair, just and reasonable?**
16 A. Excluding these costs from base rates is fair, just and reasonable as a matter
17 of principle because we do not true-up pension costs between rate cases.
18 Between rate cases, utilities may experience gains as well losses. To only
19 track one portion of pension expense – additional costs between rate cases –
20 is cherry-picking and does not represent a balanced approach to ratemaking.
21 Much like other parts of revenue requirement that vary between cases, it is not

[25] UM 1992, Staff/100, Fox/11 and Staff/100, Fox/8-9.

appropriate to single out the costs for individual cost recovery that only benefit the utility.

In the Company's case specifically, it has previously absorbed curtailment gains, which would have benefited ratepayers, in regulatory lag. The Company then sought deferral of the 2018 settlement loss which would have resulted in additional costs for customers. This history is extensively documented in the UM 1992 document and does not need to be repeated here. However, the history of curtailment gains and settlement losses has been included in this case as Staff Exhibit 1002.

Also, the Company's plan was frozen and new benefit accruals ended on December 31, 2016.[26] This means that curtailment gains are no longer possible because benefit are no longer being accrued. Only additional settlement losses are possible. I have demonstrated that curtailment gains and settlement losses (FAS 88) are not included in the Commission's definition of pension costs for rate recovery, which only includes net periodic benefit cost (FAS 87).

Changing the definition to include settlement costs at this late stage of the plan, after the plan has been frozen, after many years of the Company benefitting from regulatory lag to shield curtailment gains, is simply inequitable to ratepayers.

Q. The Company also states that pension costs in base rates are generally "black box" and "it is inappropriate to view what was

[26] PAC/300, Kobliha/30.

presented in the Company's last general rate case filing as "in rates" and to compare that against the actual pension costs recognized to derive an estimate of over or under collection of these costs from customers," how do you respond?

A. First, the Company's response in this case contradicts its position in UM 1992, in which it was able to produce the information.[27]

Second, the Company's positon varies based on what it is seeking to accomplish at the moment. Curtailment gains are managed holistically and ought to be kept as long as the Company is not earning its rate of return;[28] whereas if a significant settlement loss arises then a deferral is appropriate, because the Company has been injured. The Company seeks to have an inequitable solution to variances in pension costs, which is baseless and unsupported. It is also contrary to the Commission's longstanding policy. Although the Company provides testimony as to why it asserts a settlement loss is likely in 2021,[29] this is entirely speculative and if considered in rates, may very well result in a substantial over recovery of pension costs. The test year is normalized and intended to reflect ongoing operations, not the specific, one-time events that may occur.

Q. Does Staff support the Company's proposed resolution of establishing a deferral or balancing account?

[27] UM 1992, OPUC Information Request 4.
[28] UM 1992, PAC/200, Kobliha/6.
[29] PAC/300, Kobliha/32-35.

A. No. The Company's proposal would allow for dollar for dollar recovery of settlement costs only or all pension costs, respectively. Either proposal is unbalanced and inequitable to ratepayers after many years of the Company enjoying the benefits of regulatory lag with respect to pension costs and retained gains. Also, as discussed above, the plan is frozen and it's also inequitable to establish an extraordinary rate mechanism at this point in the plan's lifecycle.

Q. What does Staff recommend?

A. Staff recommends the Commission hew to its long standing policy of including the net periodic benefit cost (FAS 87) in base rates.

1 **ISSUE 5, GROSS UP OF TCJA BENEFITS**

2 **Q. Please summarize Staff's Opening Testimony and the Company's**
3 **Reply Testimony regarding gross up of the TCJA benefits due to**
4 **PacifiCorp's Oregon ratepayers.**

5 A. Regarding Tariff Schedule 195 – Federal Tax Act Adjustment, Staff proposed
6 the following:[30]

7 • An increase in the projected benefit due to Oregon ratepayers of
8 $6,142,017 reversing a change in gross up percentage applied to EDIT
9 benefits subsequent to Commission Order No. 19-017.
10 • Amortization of the remaining benefit to continue at the current rate of
11 $4.019 million per month until all benefits have been returned to
12 customers rather than 3 years as proposed by the Company.

13 In its Reply Testimony, the Company states that "Staff misunderstands the
14 reason for the tax gross up in calculating the EDIT balance and why it only
15 includes the federal and state income taxes."[31]

16 The Company also proposes to reduce the total amount to be returned on
17 Schedule 195 beginning in 2021 from $74.7 million to be returned over 36
18 months[32] to $11.1 million to be returned over 24 months.[33] The majority of the
19 difference is due to the Company's new proposal to apply $64.5 million of EDIT

[30] Staff/1000, Fox/10.
[31] PAC/3100, McCoy/32
[32] PAC/1313, McCoy/1.
[33] PAC/3108, McCoy/1.

1 to offset Cholla Unit 4 Unrecovered Balances and Closure Costs. Staff would
2 reconcile the remaining $11.1 million as follows:
3 • Current Tax Benefits Deferral 12/31/20 $50.6 million[34]
4 • Projected EDIT Amortization Deferral $21.1 million[35]
5 • Unrecovered EDIT associated with Cholla 4 (AWEC proposal) ($3.9)
6 million[36]
7 • Oregon allocation of Cholla 4 closure costs[37] ($64.5) million
8 **Q. Returning to the Company's assertion that there is a**
9 **"misunderstanding" regarding the gross up factor, do you agree?**
10 A. Partly, as further discussed below. First, the following table illustrates Staff's
11 initial concern.

[34] PAC/1313, McCoy/1.
[35] *Id.*
[36] PAC/3100, McCoy/36.
[37] PAC/3106, McCoy/1.

1 **Table 1**

Illustrative Ratemaking Journey of $1 in Excess Deferred Income Taxes (EDIT)

UE 246 Taxes and Fees			
Operating Revenue	100.000%	$	4.15
Uncollectable Accounts	-0.517%		(0.02)
Franchise Tax	-2.300%		(0.10)
Resource Supplier Tax	-0.080%		(0.00)
State Taxes	-4.408%		(0.18)
Federal Taxes	-32.443%		(1.35)
	60.252%	$	2.50

PacifiCorp Proposed EDIT Gross Up			
Operating Revenue	100.000%	$	1.33
State Taxes	-4.540%		(0.06)
Federal Taxes	-20.047%		(0.27)
	75.413%	$	1.00

Current rate case:
Company offers to return $1 EDIT to rate payers as a benefit to customers along with tax saved due to less revenue collected. Corresponding reduction in other revenue sensitive costs is ignored.

Deferred Taxes	$ 2.50	→	$(1.00)	→	$1.50	Ongoing Balance

Oregon customers pay $4.15 to create $2.50 in Deferred Taxes.
Federal tax rate 35% any year before 2017.
Due to normalization taxes are collected up front at 35% but taxes not actually paid until a future year at an unknown rate.

2017 Tax Reform:
Rate changes from 35% to 21%
a 40% rate reduction.
A corresponding portion of Deferred Taxes becomes Excess $1.00/2.50 = 40%

2
3
4 Based on this analysis, Staff questioned whether ratepayers are receiving the benefit of revenue sensitive costs.

Q. Has Staff's view of the gross up issue changed?

A. Partly, based on an informal discussion with the Company that occurred on July 14, 2020. The discussion was wide ranging and there seemed to be differing points of view regarding the mechanics of how returning EDIT as a tariff rider or offset to undepreciated plant would change the amount of revenue sensitive costs ultimately returned to rate payers.

Subsequent to the meeting, Staff prepared a series of hypothetical examples illustrating the effects of returning EDIT under various ratemaking scenarios. This information is Staff Exhibit 1801.

- Based on examples 3 through 4, Staff concludes that, after offsetting the unrecovered plant balances for repowered wind and Cholla 4, the parties are in the same position as if the plant continued to depreciate and the offsetting EDIT were returned in base rates. Accordingly, Staff proposes no adjustment for that portion of the EDIT return.
- Based on examples 1 and 2, Staff concludes that returning the remaining costs in a tariff rider rather that base rates results in the Company retaining the benefit of the revenue sensitive costs. Staff continues to recommend increasing the EDIT portion of schedule 195 to include the revenue sensitive costs.

Q. How does the Company's calculation unfairly reduce the amount of EDIT returned to customers on Schedule 195?

A. Staff's understanding of the Company's position is that revenue sensitive costs are estimated in base rates and are not included in the calculation of tariff

1 adjustments arising in between rate cases. While Staff would agree for
2 deferrals and other adjustments arising after a rate case is concluded, the
3 difference between the 1.369 conversion factor and the EDIT gross up of 1.326
4 is being unfairly retained by the Company as it arises from the rate case itself.
5 In other words, customers should receive the same amount whether the EDIT
6 is returned in base rates or on a tariff rider. The tariff rider will reduce revenues
7 and the Company will enjoy lower revenue sensitive costs as a result.

8 **Q. Is Staff also proposing to adjust the remaining current tax benefits**
9 **deferral?**

10 A. No, the amount of these benefits was set in the deferral docket and has
11 already been grossed up to include revenue sensitive costs.

12 **Q. What is Staff's position regarding the Company's proposal to amortize**
13 **the remaining Schedule 195 benefits over 24 months.**

14 A. Assuming the parties all agree to the Cholla 4 offsets in concept, Staff is
15 amenable to amortizing the remaining benefits over 24 months, at the weighted
16 average cost of capital plus 100 basis points which is consistent with the
17 Commission's long-standing policy on the interest rate applicable to deferral
18 accounts in amortization.

19 **Q. What is Staff's recommendation to the Commission?**

20 A. Staff recommends the remaining Schedule 195 benefits, as stated on Exhibit
21 PAC/3108, be increased from $11,088,292 to $11,904,488 calculated as
22 follows and this higher amount be amortized over two years.

	PAC/3108 McCoy/1	Increase Gross Up	Staff Proposed
Current Tax Benefits Deferral 12/31/20	$50,643,669	$ -	$50,643,669
Projected EDIT Amortization Deferral	21,063,266	689,565	21,752,831
Unrecovered EDIT associated with Cholla 4	3,868,018	126,630	3,994,648
	75,574,953	816,195	76,391,148
Oregon allocation of Cholla 4 closure costs	(64,486,660)	-	(64,486,660)
	$11,088,293	$ 816,195	$11,904,488

1

1 **ISSUE 6, OTHER RECOMMENDATIONS**

2 **Q. Does Staff have further recommendations regarding the following[38]?**

3 • Trapper mine final reclamation liability

4 • ILR 4.1.9 Future Fish Passage Stage 1 Ph

5 • Central Utah Water Conservancy District (CUWCD) project

6 A. No, Staff supports the adjustments described by the Company in reply.[39]

7 **Q. Does Staff support the Company's proposal to limit attestations to**
8 **projects in excess of $5 million instead of $1 million as proposed by**
9 **Staff?**

10 A. Not at this time.

11 **Q. Does Staff support the Company's proposed correction of Pro Forma**
12 **Tax Balances[40]?**

13 A. Yes.

14 **Q. Does this conclude your testimony?**

15 A. Yes.

16

[38] Staff/1000, Fox/20
[39] PAC/3100, McCoy/37 and PAC/3100, McCoy/56-57
[40] PAC/3100, McCoy/32.

CASE: UE 374
WITNESS: JOHN L. FOX

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STAFF EXHIBIT 1801

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

EDIT Return Example Calculations

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		Initial	Equip							
2		Setup	Offset	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6	Total
3	Example 1 - return of $1,326 EDIT Regulatory Liability in base rates over 6 years									
4	Balance Sheet:									
5	EDIT Regulatory Liability	(1,326)		221.00	221.00	221.00	221.00	221.00	221.00	-
6	Income Statement:									
7	Rate Reduction			(228.50)	(228.50)	(228.50)	(228.50)	(228.50)	(228.50)	(1,371.00)
8	Federal and State Taxes			54.33	54.33	54.33	54.33	54.33	54.33	326.00
9	Other Revenue Sensitive			7.50	7.50	7.50	7.50	7.50	7.50	45.00
10	Net Revenue to PacifiCorp			(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	(1,000.00)
11	Total Benefits:									
12	Ratepayers			(228.50)	(228.50)	(228.50)	(228.50)	(228.50)	(228.50)	(1,371.00)
13	PacifiCorp			-	-	-	-	-	-	-

EDIT Return Example Calculations

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		Initial	Equip							
2		Setup	Offset	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6	Total
14	Example 2 - return of $1,326 EDIT Regulatory Liability as a tariff rider over 6 years									
15	Balance Sheet:									
16	EDIT Regulatory Liability	(1,326)		221.00	221.00	221.00	221.00	221.00	221.00	-
17	Income Statement:									
18	Rate Reduction			(228.50)	(228.50)	(228.50)	(228.50)	(228.50)	(228.50)	(1,371.00)
19	Federal and State Taxes			54.33	54.33	54.33	54.33	54.33	54.33	326.00
20	Other Revenue Sensitive			7.50	7.50	7.50	7.50	7.50	7.50	45.00
21	Net Revenue to PacifiCorp			(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	(1,000.00)
22	Total Benefits:									
23	Ratepayers			(221.00)	(221.00)	(221.00)	(221.00)	(221.00)	(221.00)	(1,326.00)
24	PacifiCorp			(7.50)	(7.50)	(7.50)	(7.50)	(7.50)	(7.50)	(45.00)

EDIT Return Example Calculations

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		Initial	Equip							
2		Setup	Offset	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6	Total
25	Example 3 - $1,000 Equipment depreciated in base rates over 6 years									
26	Balance Sheet:									
27	Utility Plant	1,000		(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	-
28	Income Statement:									
29	Rate Increase			228.50	228.50	228.50	228.50	228.50	228.50	1,371.00
30	Federal and State Taxes			(54.33)	(54.33)	(54.33)	(54.33)	(54.33)	(54.33)	(326.00)
31	Other Revenue Sensitive			(7.50)	(7.50)	(7.50)	(7.50)	(7.50)	(7.50)	(45.00)
32	Net Revenue to PacifiCorp			166.67	166.67	166.67	166.67	166.67	166.67	1,000.00

EDIT Return Example Calculations

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		Initial	Equip							
2		Setup	Offset	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6	Total
33	Example 4 - Equipment depreciation plus return of $1,326 EDIT Regulatory Liability in base rates over 6 years									
34	Balance Sheet:									
35	Utility Plant	1,000	-	(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	-
36	EDIT Regulatory Liability *	(1,326)		221.00	221.00	221.00	221.00	221.00	221.00	-
37	Income Statement - Depreciation:									
38	Rate Reduction			228.50	228.50	228.50	228.50	228.50	228.50	1,371.00
39	Federal and State Taxes			(54.33)	(54.33)	(54.33)	(54.33)	(54.33)	(54.33)	(326.00)
40	Other Revenue Sensitive			(7.50)	(7.50)	(7.50)	(7.50)	(7.50)	(7.50)	(45.00)
41	Net Revenue to PacifiCorp			166.67	166.67	166.67	166.67	166.67	166.67	1,000.00
42	Income Statement - Return of EDIT:									
43	Rate Reduction			(228.50)	(228.50)	(228.50)	(228.50)	(228.50)	(228.50)	(1,371.00)
44	Federal and State Taxes			54.33	54.33	54.33	54.33	54.33	54.33	326.00
45	Other Revenue Sensitive			7.50	7.50	7.50	7.50	7.50	7.50	45.00
46	Net Revenue to PacifiCorp			(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	(166.67)	(1,000.00)
47	Income Statement - Net:									
48	Rate Reduction			0	0	0	0	0	0	0
49	Federal and State Taxes			-	-	-	-	-	-	-
50	Other Revenue Sensitive			0	0	0	0	0	0	0
51	Net Revenue to PacifiCorp			0	0	0	0	0	0	0

52 * Regulatory Liability is $1,000 EDIT plus $326 gross up for taxes which is offset by a $326 deferred tax debit. Net is $1,000.
53 See PAC/3100, McCoy/33 for discussion of offset.

CASE: UE 374
WITNESS: JOHN L. FOX

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STAFF EXHIBIT 1802

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

UE 374/PacifiCorp
May 12, 2020
OPUC Data Request 389

OPUC Data Request 389

Utility Plant
Regarding the Company's response to Staff Data Request 222 and OPUC 222-1 Attach.xlsx:

(a) Please provide the data and/or analysis supporting the following statement therein "The AMI program delivers annual benefits that offset the cost of implementation and avoids the need to raise customer rates while also positioning the company to be able to offer additional potential benefits long-term."

Response to OPUC Data Request 389

The following verbiage describes savings which offset the cost of implementing the Oregon Automated Metering Infrastructure (AMI) project. Further, these savings will help offset the magnitude of future rate increases. Customer benefits are also included for discussion.

Financial Benefits:

- The project will deliver $13m in annual net benefits following the first full year of implementation (2020).
  - Reduced operations and maintenance (O&M) cost: $7,682,624
  - Additional Revenue: $4,075,738
  - Reduced capital expenditures: $1,204,266

Reduced O&M:

O&M Savings	Annual Benefits *(starting in 2020)*
Eliminate Meter Reading Operating Costs	$6,901,489
Eliminate Collection Operating Costs	$1,767,239
Eliminate Journeyman Metermen Operating	$594,741
Eliminate Service Coordinators Costs	$218,145
Eliminate Meter Manager Operating Costs	$1,013,616
Eliminate Overtime (Metering and T&D)	$797,394
Avoided Handheld Maintenance and Repair	$91,712
Billing Suspends Reduction	$55,583
New AMI operating costs	($3,757,294)
O&M Savings	**$7,682,624**

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

Additional Revenue:

Additional Revenue	Annual Benefits *(starting in 2020)*
Theft Reduction	$675,624
Reduced Power Losses	$736,406
Revenue from Added Meters with VARs	$345,562
System Energy Loss Reductions	$507,095
Revenue Recovery on Unaccounted for Energy	$1,144,056
Reduction in Write-offs	$666,995
Additional Revenue	**$4,075,738**

Reduced capital expenditure:

Capital Cost Savings	Annual Benefits *(starting in 2020)*
Avoided Meter Purchases	$974,187
Avoided Load Study Costs	$41,209
Avoided Handheld replacement costs	$191,193
Capital Cost Savings	**$1,204,266**

Customer benefits:

- Establish unique rate structures aimed at delivering specific customer driven needs/benefits, e.g. irrigators, etc.
- Enable creation and participation in enhanced energy conservation programs.
- Provides customers access to data regarding their hourly energy consumption, which will enable them to make more informed energy decisions and manage their costs.
- Improve the quality of communication with customers with particular emphasis on outage restoration efforts/conditions.
- Reduce the frequency and length of outages, thereby reducing the financial impact to customer operations and improve the reliability metrics.
- Shorten service connection times, thereby freeing up customer wait time and enhancing receipt of service.
- Proactively addressing aging equipment versus reactively addressing it, therefore improving the customer experience, e.g., fix it before it breaks.
- Allows proper equipment sizing which ultimately saves ratepayer money.
- Establishes a real time utility to customer meter foundation, from which new and yet to be created smart grid technology can be delivered.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

UE 374/PacifiCorp
May 12, 2020
OPUC Data Request 389

- Improved bill accuracy resulting in fewer estimated bills.
- More timely resolution of bill inquiries.
- Carbon dioxide reductions due to fewer vehicles on the road.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

UE 374/PacifiCorp
June 4, 2020
OPUC Data Request 592

OPUC Data Request 592

Regarding the Company's response to Staff Data Request 389:

(a) Please identify the nature of the New AMI operating costs of $3,757,294 cited for 2020 above the $2.5 million new O&M costs for 2019 cited in testimony at PAC/1100, Lucas/27.

(b) Please confirm whether the first full year of implementation is 2019 as stated in testimony or 2020 as stated in the response to Staff Data Request 389.

(c) Please provide a summary of what portion of the 2020 financial benefits and/or new O&M costs are included in base year operating results, if any.

Response to OPUC Data Request 592

(a) The $3.8 million new advanced metering infrastructure (AMI) operating costs was the original estimate included in the 2016 business case. Contract negotiations, improved business processes, synergies with California AMI and network performance enabled a reduction in projected new AMI operating costs (now estimated to be $2.5 million per year, beginning in 2020).

(b) The project completed in 2019; the first full year after implementation is 2020.

(c) The Company estimates that PacifiCorp achieved approximately 45 percent of its net operational 2020 benefits in the base year.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

CASE: UE 374
WITNESSES: MATT MULDOON-MOYA ENRIGHT-CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1900

Rebuttal Testimony

REDACTED
July 24, 2020

1 **Q. Please each state your name and occupation.**

2 A1. My name is Matt Muldoon. I am the Economic Analysis Program Manager
3 within the Energy Rates, Finance, and Audit (ERFA) Division of the Public
4 Utility Commission of Oregon (Commission or OPUC).

5 A2. My name is Moya Enright. I am a Senior Utility and Energy Analyst in the
6 OPUC ERFA Economic Analysis Program.

7 A3. My name is Curtis Dlouhy. I am a Senior Utility and Energy Analyst in the
8 OPUC ERFA Economic Analysis Program.

9 **Q. What is your common business address?**

10 A. 201 High Street SE, Suite 100, Salem, OR 97301.

11 **Q. Are you the same Staff who authored Opening Testimony Staff**
12 **Exhibit No. 200 in this rate case and whose Witness Qualification**
13 **Statements are provided as Staff Exhibit Nos. 201 and 202?**

14 A. Yes. In addition, we are joined by Curtis Dlouhy, PhD, Economics, a Senior
15 Economist in the OPUC ERFA Economic Analysis Program, working from the
16 same address shown above. Dr. Dlouhy's Witness Qualification Statement
17 appears as Staff Exhibit No.1901, showing his educational background and
18 work experience.

19 **Q. What is the purpose of this testimony?**

20 A. The purpose of this testimony is to explain how Staff updated its Opening
21 Testimony with more current information and to show how Staff responds to
22 the testimonies of Alliance of Western Energy Consumers (AWEC) and other
23 intervenors as well as the Reply Testimony of PacifiCorp concerning Cost of

Capital (CoC) issues: Capital Structure, Return on Equity (ROE), and Cost Long-Term Debt (LT Debt).

Q. What recommendations are updated in this testimony?

A. We updated our analysis of Five CoC issues in the PacifiCorp (PAC or Company) Docket No. UE 374:

1. Capital Structure;
2. Cost of Common Equity, also known as ROE;
3. Cost of LT Debt;
4. Overall Rate of Return (ROR); and
5. Implementing an effective Green First Mortgage Bond (FMB) Program.

Q. What is your summary recommendation?

A. Staff finds that Mr. Gorman testifying for AWEC makes compelling arguments, and Staff joins AWEC in this testimony in recommending a Capital Structure of 50.64 percent equity and 49.35 percent LT Debt, moving away from Staff's earlier recommended 52 percent equity layer in Opening Testimony.

After updating its ROE modeling entirely, Staff still recommends a point ROE of 9.0 percent but now within a slightly upshifted range of reasonable ROEs of 8.57 percent to 9.42 percent.

Staff recommends the Commission adopt a 4.824 percent Cost of LT Debt based on Staff's proven methodology. A 10 bps change in cost of LT Debt is worth approximately $2.75 million revenue requirement in this case.

1 Finally, with a tremendous build of renewable generation, storage and
2 supporting transmission upcoming, Staff urges the Company to develop a
3 fully operational Green FMB program as soon as practicable.

4 **Q. Did you prepare tables showing PacifiCorp's current Commission**
5 **authorized, the Company's proposed, and Staff recommended CoC?**

6 A. Yes, the following three tables provide that information. Blue indicates values
7 under discussion in this general rate case (GRC).

8 **Table 1**

PAC Current OPUC Authorized (UE 263 Order Nos. 13-472)			PAC
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long Term Debt	47.60%	5.250%	2.499%
Preferred Stock	0.30%	5.427%	0.016%
Common Stock	52.10%	9.80%	5.106%
100.00%			**7.621%**

9

10 **Table 2**

PAC Requested – UE 374		PAC Reply Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**46.47%**	**4.77%**	2.217%	**0.055%**
Preferred Stock	0.01%	6.75%	0.001%	
Common Stock	**53.52%**	**10.2%**	5.459%	
100.00%			**7.68%**	

11

Table 3

Staff Proposed – UE 374		Staff Rebuttal Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**49.35%**	**4.824%**	2.381%	**-0.682%**
Preferred Stock	0.01%	6.75%	0.001%	
Common Stock	**50.64%**	**9.00%**	4.558%	
100.00%			**6.939%**	

Q. What Capital Structure does the Company recommend?

A. PacifiCorp continues to recommend a 53.52 percent common equity layer in Capital Structure.[1]

Q. What ROE does the Company recommend?

A. PacifiCorp continues to recommend a 10.2 percent point ROE within a range of reasonable ROEs of 9.75 and 10.25.

Within this rate case, PacifiCorp estimates each 10 basis points (bps) of ROE equates to about $3.0 million of revenue requirement.[2] Staff estimates each 10 bps more equity in Capital Structure increases revenue requirement by about $240,000.

Q. What Cost of Long Term Debt does PacifiCorp recommend?

A. PacifiCorp ask for a 4.77 percent Cost of LT Debt. As a matter of principle, Staff recommends the higher Staff calculated 4.824 percent Cost of LT Debt.

[1] PAC/2100, Kobliha/3.
[2] PAC/200, Wilding/11

Q. How is your testimony organized?

A. We organize our testimony as follows:

Issue 1 – What Has Changed 6
Issue 2 – Capital Structure 18
Issue 3 – Staff's Updated Return on Equity (ROE) 30
Peer Screen 30
Hamada Equation 31
Three Stage Discounted Cash Flow (DCF) Models 31
Analysis Cognizent of Market Conditions & other jurisdictions 39
Issue 4 – Green First Mortgage Bonds (FMB) 42
Issue 5A – Staff response to Intervenors – Other Than AWEC 50
Issue 5B – Staff response to Intervenors – AWEC 56
Issue 6 – Staff Response to PacifiCorp PAC/2200 81
Issue 7 – Staff's Update of GDP Growth Rates 96
Issue 8 – Staff's Updated Single-Stage DCF ROE Model 97
Issue 9 – Staff's Updated CAPM ROE Model 99
Issue 10 – Cost of Long-Term Debt (LT Debt) 109
Conclusion 111

1 **Q. Did you prepare exhibits in support of your rebuttal testimony?**

2 A. Yes. Staff prepared the following exhibits:

3 Staff/1902 ..... **CONFIDENTIAL** Cost of LT Debt
4 Staff/1903 ..... ROE Peer Screening
5 Staff/1904 ..... Three-Stage DCF ROE Modeling
6 Staff/1905 ..... CAPM ROE Control Modeling
7 Staff/1906 ..... Gordon Growth Single Stage DCF ROE Control Modeling
8 Staff/1907 ..... Long-Run Growth Rates
9 Staff/1908 ..... BEA Historic GDP Growth
10 Staff/1909 ..... TIPS Implied Inflation Expectations
11 Staff/1910 ..... Value Line (VL) Review of Electric Utilities
12 Staff/1911 ..... News that Investors Are Seeing
13 Staff/1912 ..... **CONFIDENTIAL** 2020 Updates from Rating Agencies

14 **ISSUE 1 – WHAT HAS CHANGED**

15 **Q. What has changed since Staff's Opening Testimony?**

16 A. A number of material changes have taken place since Staff filed Opening
17 Testimony, including:

18 1. Recovery from COVID-19 pandemic is likely to be slower than hoped.
19 2. Lower Long-Term, 20-year Gross Domestic Product (GDP) growth rates.
20 3. Unprecedented Central Bank actions and stimulus.
21 4. Fitful reopening of economy amidst rising cases of COVID-19.
22 5. Unprecedented financial extremes have no prior experience to rely on.
23 6. Potential structural and behavior change in the US economy.
24 7. Low rates, spreads, and volatility for debt and high volatility in stocks.

25 **Q. Regarding your first point, how rapidly was the economy initially**
26 **projected to grow when Staff filed their Opening Testimony?**

27 A. Immediately after the restrictions imposed to quell the spread of COVID-19,
28 the US economy went into a sharp recession. Once the restrictions were

eased, the economy experienced a period of sharp growth that brought the stock market near its pre-lockdown levels. This sudden recovery had many analysts thinking that the economic impacts of the COVID-19 pandemic would be relatively short lived.

Q. How has that forecast changed in the time since Staff's filing of opening testimony?

A. In the time since Staff's opening testimony, it has become abundantly clear that COVID-19 is here long term. As a result, investing has fallen again, labor markets have shrunk, and the Congressional Budget Office (CBO) has projected that the economy at the end of the year will be 5.6 percent smaller in 2020 than in 2019.[3] While it was common knowledge that the economy was declining by this time, the National Bureau of Economic Research officially declared the US to be in a recession in June.[4]

Q. Is this just a problem for the United States?

A. No, analysts have deemed this a worldwide problem, with the World Bank forecasting that the global economy will shrink by 5.2 percent in 2020.[5] This marks one of the worst global economic downturns in the last 150 years, matched only by the Great Recession and the end of World War II. In fact, an

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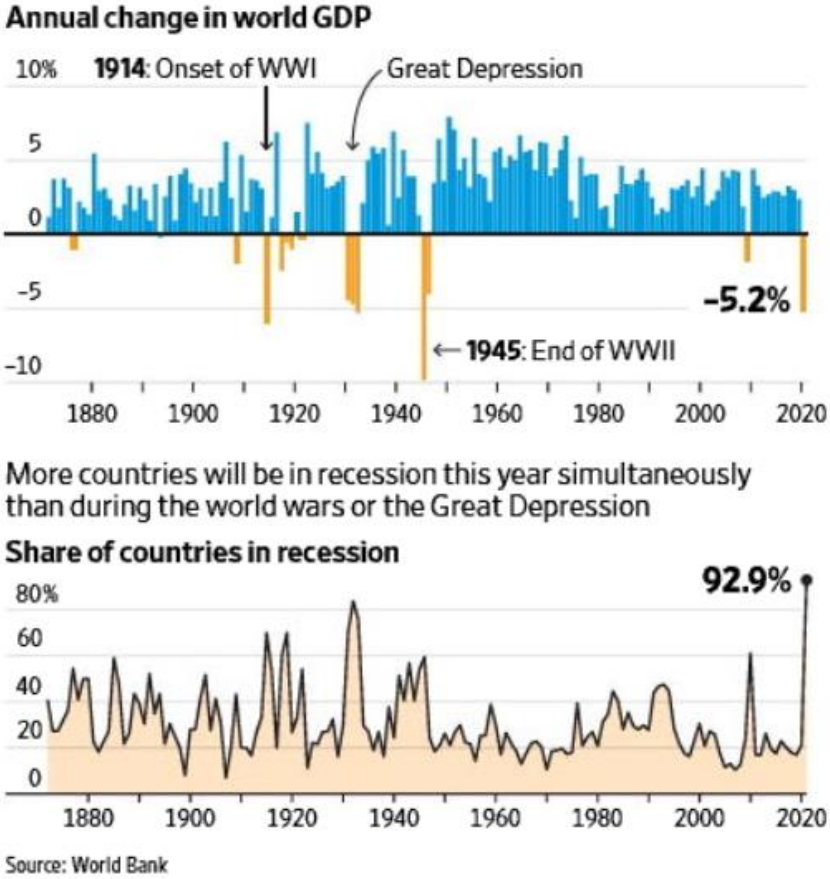
[3] See "CBO Sees Recovery Going Through 2021" by Paul Kiernan – WSJ – May 20, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/13.

[4] See "Economists Declare US Recession after 128-Month Expansion Ended in February" by Emmanuel Louis Bacani – Jun. 8, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/69.

[5] See "COVID-19 to Plunge Global Economy into Worst Recession since World War II", World Bank press release, June 8, 2020. Accessible at: https://www.worldbank.org/en/news/press-release/2020/06/08/covid-19-to-plunge-global-economy-into-worst-recession-since-world-war-ii.

estimated 92.9 percent of countries in the world are expected to simultaneously be in a recession this year, the highest mark in the last 150 years.[6] The full extent of this fall can be seen in Figure 1.

Figure 1



Q. Do experts believe that the US is primed for a steady recovery?

A. No. Recently, top officials in the Federal Reserve warned of the possibility of a double-dip recession due to early easing of lockdown restrictions.[7] On top

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6 See "Global Economy Seen Shrinking 5.2%" by Josh Zumbrun – WSJ – Jun. 9, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/97.

7 See "Key Fed Official Warns of Double Dip" by Nick Timiraos – WSJ – Jul. 15, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/143.

of that, layoffs still remain at an all-time high,[8] and the number of Americans collecting unemployment checks is not expected to return to pre-pandemic levels until after 2030.[9,10]

Q. Has unemployment led to any other changes in financial markets that are relevant to this rate case?

A. Yes. The rise in unemployment and the slower-than-expected recovery led to investors fleeing to safe investment. This has recently caused the yield on US Treasury bonds to fall even further.[11] The Federal Reserve has also promised to keep interest rates low by buying back US Treasury bonds, which further justifies a lower rate of return for PacifiCorp.

Q. Regarding your second point, who projects long-term growth rates and how have they changed recently?

A. Many government organizations as well as private ones project long-term growth rates. Notably, the CBO released a revised 10-year projection in June, where they revised down their 10-year GDP projection by 3 percent, or a cumulative $7.9 trillion.[12]

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8 See "Layoffs Fell to 7.7 Million in April" by Sarah Chaney – WSJ – Jun. 10, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/144.

9 See "Jobless Claims Reflect a Slow Mend" by Sarah Chaney and Kim Mackrael – WSJ – Jun. 12, 2020. Reproduced in Exhibit Staff/1911 Part A, Page 142.

10 See "Unemployment rate won't recover for the next decade, CBO projects," by Anneken Tappe of CNN Business, July 2, 2020. Accessible at: https://www.cnn.com/2020/07/02/economy/congressional-budget-office-projections-economy/index.html

11 See "Bond Yields Fall As Jobless Claims Top Expectations" by Sebastian Pellejero. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/294.

12 See "Economy Setback Seen Taking 10 Years to End" by Paul Kiernan and Paul Hannon. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/34-36.

1 **Q. Why are these long-term growth rates so low even if a vaccine is**
2 **likely to be found within the next year?**
3 A. The article above noted that factory output has fallen dramatically in the
4 United States. Even with a vaccine, it will likely take some time for the
5 vaccine to be properly distributed, people to find jobs, and normal activity to
6 resume.
7 **Q. Regarding your third point, what fiscal actions have been taken in**
8 **response to COVID-19?**
9 A. Across the world, governments are trying to ease the burden of the stringent
10 lockdowns. In addition to all the well-documented consumer and business
11 relief effort in the US, the European Union recently unveiled a 750 billion euro
12 pledge to aid in financial recovery.[13]
13 **Q. Regarding your third point, what monetary actions have been taken in**
14 **response to COVID-19?**
15 A. The Federal Reserve also began offering to buy corporate bonds in March in
16 order to reignite credit markets, but companies are reluctant to sign up for this
17 program due to possibly appearing weak during a credit market rebound.[14]
18 In a move that is unprecedented since post-World War II, the Federal
19 Reserve announced that it plans to cap US Treasury yields in order to

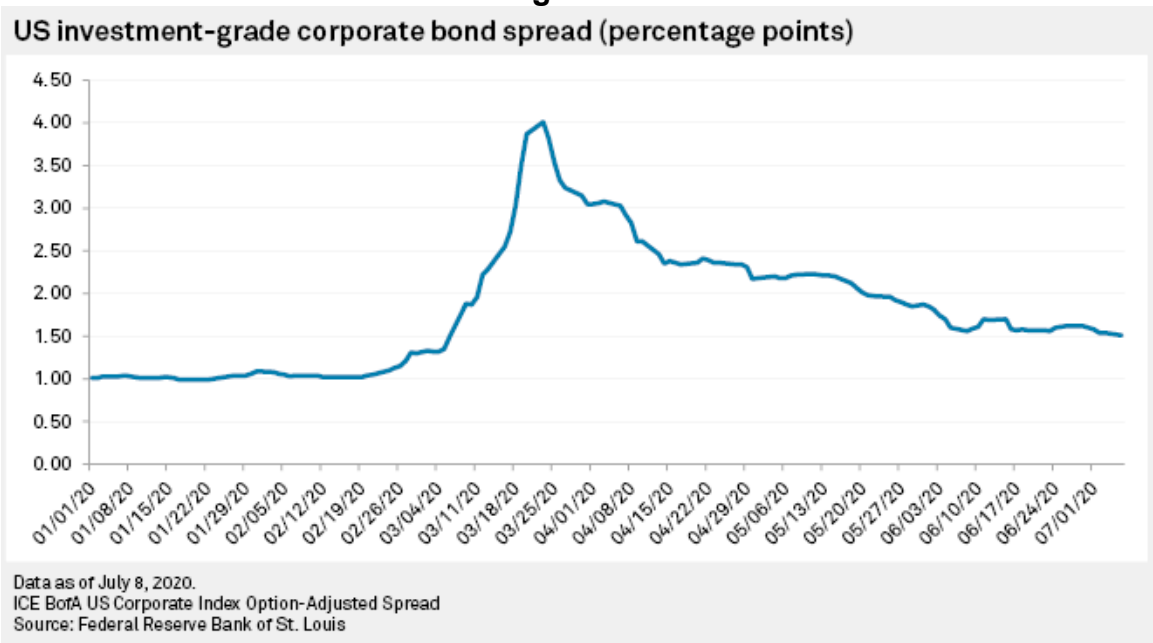
[13] See "European Union Sets Out Major Coronavirus Recovery Plan" by Laurence Norman – WSJ – May, 27, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/77-78.
[14] See "Central Bank Finds No Bond Sellers" by Matt Wirz – WSJ – Jun. 4, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/14-15.

1 incentivize more investment.[15] While investors note that this is relatively
2 unknown territory, it is expected that targeting low treasury yields would result
3 in value stocks becoming relatively less attractive.[16] The Federal Reserve
4 intends to keep interest rates low at least through 2022.[17]

5 **Q. How are these actions relevant to rate case proceedings?**

6 A. The Fed's actions have kept rates exceptionally low, which means that
7 corporate debt is cheaper than it has been for quite some time. In fact, the
8 US Investment-grade corporate bond spread has fallen to its lowest level
9 since the pandemic. This can be seen in Figure 2 below.

10 **Figure 2[18]**



11

15 See "Fed Aims to Fortify Low-Rate Pledge" by Nick Timiraos – WSJ "The Outlook Column" – Jun. 8, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/79-81.

16 See "Fed Looks to Put Cap on Treasury Yields" by Caitlin Ostroff and Sebastian Pellejero – WSJ – Jun. 2, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/11-13.

17 See "Fed Plans to Keep Rates at Low Levels for Years" by Nick Timiraos – WSJ – Jun. 11, 2020. Reproduced in Exhibit Staff/191, Muldoon-Enright-Dlouhy/81-82.

18 See "Investment-Grade US Corporate Spreads Hit Four-Month Low – Risk Monitor" by Peter Brennan – S&P Global Market Intelligence – Jul. 8, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/118-119.

1 **Q. Regarding your fourth point, how have the spasmodic reopening**
2 **actions in response to COVID-19 affected the economy?**
3 A. First and foremost, the asymmetric and sometimes poorly regulated re-
4 openings at the state level have led to a large spike in COVID-19 infections
5 across the United States. This has led experts to believe that the US might
6 be vulnerable to a double-dip recession.[19]
7 **Q. How is a double-dip recession relevant to rate case proceedings?**
8 A. At the very least, a double-dip recession means that the economic recovery
9 could take even longer than anticipated. This means that the unemployment
10 rate could remain high, GDP growth could remain low and utility customers
11 could have continued struggles paying their bills on time.
12 **Q. Regarding your fifth point, have events like these occurred before?**
13 A. No. The U.S. federal and state governments never before mandated that
14 much of the economy shut down. Routine activities like riding in a bus, train,
15 or airplane, even attending a sporting event or going to work in a busy office
16 or factory all became risky activities. The scale and intensity of financial
17 events are new experiences without a living memory precedent to draw
18 comparison to.
19 **Q. How does John Lonski, Chief Economist for Moody's Capital Markets**
20 **Research, Inc. (Moody's) articulate this?**
21 A. He states:

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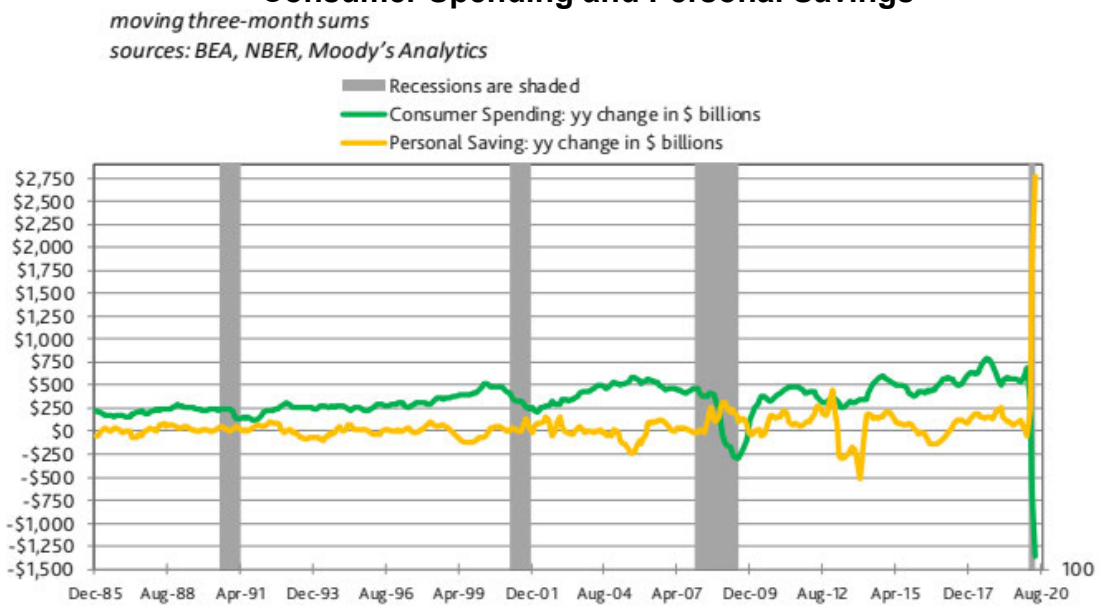
[19] See "Key Fed Official Warns of Double Dip" by Nick Timiraos – WSJ – Jul. 15, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/144.

Never before has a $1.4 trillion yearly contraction by consumer spending been accompanied by a $2.8 trillion yearly surge by personal savings. Such extremes are without any remotely similar precedent. Prior to 2020, the widest gap between a year-over-year increase by personal savings and a year-over-year contraction by consumer spending occurred near the end of 2008-2009's Great Recession. More specifically, for the three-months-ended May 2009, a $198 billion annual increase in personal savings accompanied a consumer spending $273 billion annual contraction.[20] This can be seen in Figure 3.

Figure 3
Consumer Spending and Personal Savings



Q. What does this mean in everyday terms?

A. People effectively stopped spending, putting all their money aside to deal with an uncertain future they have never faced before. Indeed, people were asked

[20] See Moody's Analytics Weekly Market Outlook of July 9, 2020

1 to shelter in place indefinitely and mandated closures greatly reduced access
2 to shopping, lodging, travel, restaurants, bars, events and even workplaces.
3 Mr. Lonsky is pointing out that looking at the historical events like the financial
4 crisis of 2008-2009 does not give one good information to draw on from a like
5 situation in predicting where things go from here.

6 **Q. Regarding your sixth point, why would COVID-19 fundamentally alter**
7 **the way agents behave in these long-standing economic institutions?**

8 A. COVID-19 has altered consumer and investor outlook into the future. As
9 previously mentioned, consumer spending has dropped and personal savings
10 have risen by levels unseen for over 30 years. On top of that, investors have
11 had to try extra hard to balance protection against a stock market crash, hold
12 safe assets while the market is low, and be ready for a suddenly rebounding
13 market. This has led analysts to recommend more call options.[21] Other
14 assets that have proved reliable for the last decade have suddenly crumbled,
15 such as Leveraged Exchange-Traded Notes.[22]

16 On top of that, many investors have chosen to pull out of the stock
17 market entirely and convert their stock into cash equivalents. Notably,
18 Berkshire Hathaway increased its cash and short-term investments to nearly

[21] See "Investors Have Deep Fear of Missing Out" by James Mackintosh – WSJ Streetwise Column – Jun. 15, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/9-10.

[22] See "Bankrupt in Just Two Weeks – Individual Investors Get Burned by Collapse of Complex Securities" by Akane Otani and Sebastian Pellejero – WSJ – Jun. 1, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/21-28.

1 $140 billion.[23] Companies believe that the added flexibility of cash is more
2 valuable in the uncertain times ahead.[24]
3 On top of that, many existing bonds have been downgraded as the COVID
4 crisis makes corporate debt-financed buybacks appear riskier.[25]
5 **Q. Does this go against your seventh point saying that debt has become**
6 **less volatile, less risky and relatively cheap?**
7 A. Initially, yes it would. However, the riskier debt necessarily led to higher
8 yields, which attracted a plethora of investors from Europe and Asia. This
9 influx of foreign lenders along with efforts by the Federal Reserve have
10 stabilized the debt market in the US and ultimately kept corporate borrowing
11 costs in the US low.[26] In Figure 2 that was previously introduced, one can
12 see that the spread between investment-grade bonds and US treasury yields
13 has fallen in the previous three months.
14 **Q. How persistent has this inexpensive debt been?**
15 A. Debt has remained incredibly inexpensive since the start of lockdowns in
16 mid-March and continues to remain inexpensive. This applies to a variety
17 of types of debts, as the average 30-year mortgage rate has fallen, the

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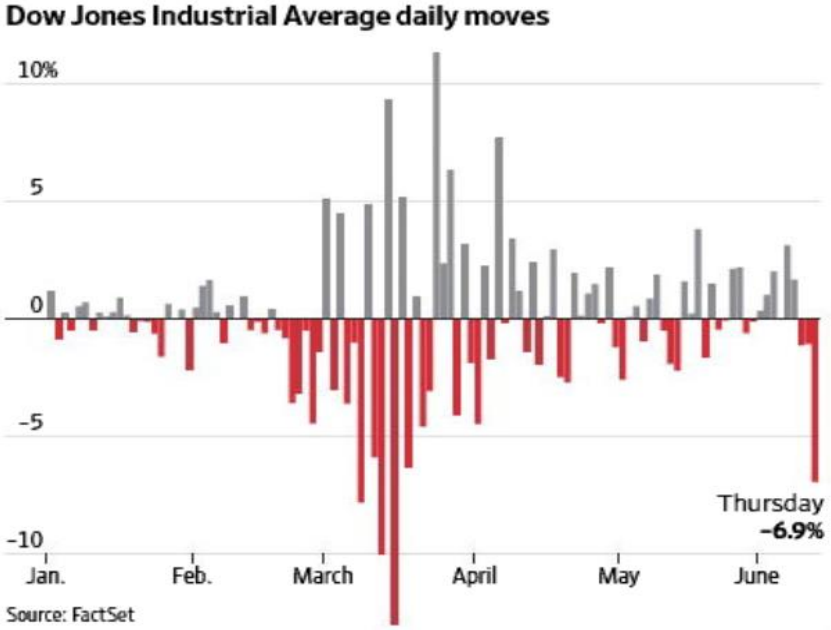
[23] See "Warren Buffett's Berkshire Hathaway Reports $49.7 Billion Loss for First Quarter" by Geoffrey Rogow – WSJ – May 2, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/40-42.
[24] See "Crisis Boosts Cash Allure to Firms" by Thomas Gyrta and Theo Francis – WSJ – Jun. 22, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/43-45.
[25] See "Crisis Upends Corporate Borrowing Binge" by Cezary Podkul and Ana Rivas – WSJ – Jun. 25, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/46-47.
[26] See "Debt from American Companies Lures Asian, European Investors" by Joe Wallace and Frances Yoon – WSJ – Jun. 29, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/50-52.

yield on all US Treasury notes has fallen, and the spread between mortgage rates and 10-year US Treasury notes has also fallen.[27]

Q. Regarding your seventh point, what has caused stocks to become so much more volatile?

A. The volatility of the stock market can be attributed to investors' ever-changing expectations of the economy. Every day, investors are bombarded with news about how the economy is reopening, the economy is shutting down, cases are rising, cases are falling, a vaccine is years away, or a vaccine is months away. The information in the era of COVID-19 is so fluid, and investment decisions are made based on the most up-to-date set of information. This has caused daily returns to vary wildly, as shown in Figure 4.

Figure 4[28]



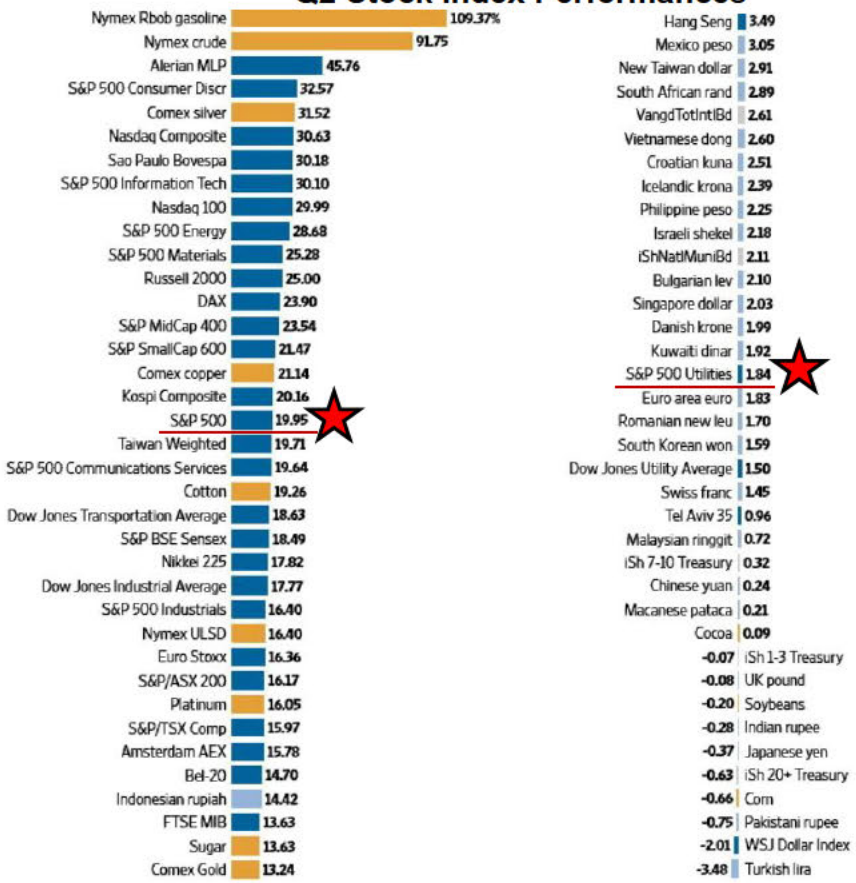
[27] See "Rate for 30-Year Mortgage Falls to Lowest on Record" by Orla McCaffrey – WSJ – Jul. 17, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/291-293.

[28] See "Dow Falls 1,800 on Virus Worries" by Akane Otani and Caitlin Ostroff – WSJ – Jun. 12, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/64-67.

Q. Are there any other factors that contributed to this volatility?

A. Yes. Investors that see volatility in the market come to expect it, and then plan their investment strategies around the volatility. This has the effect of making wild markets even more turbulent.[29] This has translated even into utility investment even though utilities have long-since been believed to be stable.[30]

Figure 5[31]
Q2 Stock Index Performances



29 See "Investors Bet on Volatility, Making Markets Even Wilder" by Gunjan Banerji – WSJ – Jun. 13, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/123-127.

30 See "Safe Utilities Have Been More Volatile Than Broader Stock Market" by Anna Hirtenstein of WSJ – June 24, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/184-187.

31 See "Track the Market – Winners and Losers for 2020 Q2" – WSJ – Jul. 1, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/223-227.

Q. Does this increased volatility translate into increased returns for utility companies?

A. No. While it may be reasonable to think that the dramatic increase volatility would translate into an increase in returns through added risk premiums, this is just not the case in the utilities sector. Figure 5 presents the average returns for various market indices, currencies and other investments. The S&P 500 Index return far outweighs that of the S&P 500 Utilities Index.

ISSUE 2 – CAPITAL STRUCTURE

Q. What is Staff's recommendation for Capital Structure?

A. Staff finds that Mr. Gorman testifying for AWEC makes compelling arguments, and Staff joins AWEC in this testimony in recommending a Capital Structure of 50.64 percent equity and 49.35 percent LT Debt, moving away from Staff's earlier recommended 52 percent equity layer in Opening Testimony.

Q. Did PacifiCorp respond to Staff and AWEC's opening testimony on Capital Structure?

A. Yes, PacifiCorp addressed both Staff and AWEC's opening testimony regarding capital structure.

With regard to Staff's testimony, PacifiCorp claims that Staff did not account for the 2017 Tax Cuts and Jobs Act (2017 Tax Act) and the Company's forecasted capital spending in its analysis, and explains how it expects these factors to increase the equity proportion of capital structure

needed to meet rating agency metrics.[32] Further, PacifiCorp rejected two of Staff's observations: that the Commission has historically favored a balanced capital structure and that at this time of historically low interest rates, that it would be reasonable for the Company to increase its use of LT Debt, given the current historically low interest rate environment.

With regard to AWEC's testimony, PacifiCorp opines that the historic period reviewed by AWEC does not reflect its future capital structure, or the 2017 Tax Act. It also rejects AWEC's assertion that imputed debt (used for credit metric purposes) is expected to decline over time.

Q. Does Staff agree with PacifiCorp's assessment of its opening testimony?

A. No. Staff appreciates the Company's awareness of credit ratings and its record of successfully issuing debt. However, in the interest of ensuring fair and reasonable rates, Staff's concerns lay in the need for an optimal capital structure, striking a balance between the *guaranteed* incremental cost resulting from a higher equity proportion, and the *potential* debt cost savings, aided by its meeting rating agency metrics with a comfortable margin.

Q. How has the Commission considered that an optimal capital structure ensures a balance between costs and benefits in the past?

[32] PAC/2100, Kobliha/2.

A. As indicated in Staff's opening testimony, the Commission has traditionally favored balance in capital structures. As demonstrated by past Commission decisions, a 50/50 capital structure has strong precedent in Oregon.[33] In spite of this, Staff's recommendation in opening testimony included a generous recommended capital structure of 52 percent equity, which is supportive of PacifiCorp's funding needs, while also conscientious of the resulting increase in costs to PacifiCorp's customers.

Q. How do independent observers view the issue of an optimal capital structure?

A. As the importance of balancing the increased cost of a higher equity proportion against its benefits was recently highlighted in a report by Regulatory Research Associates (RRA). RRA stated:

> The return should be sufficient to allow the utility to attract capital commensurate with its level of risk, to assure confidence in the company's financial integrity and support the company's credit. Commissions must also weigh the implications on ratepayers, ensuring safe and reliable utility service at a reasonable cost.[34]

[33] See Docket No. UE 180, Order No. 07-015, pages 30 – 31, in which the Commission determined "The Commission is not required to adopt PGE's actual capital structure, but can select an alternative capital structure in consideration with the other factors that affect the cost of capital." In this example, the Commission adopted a capital structure of 50 percent equity and 50 percent debt, as recommended by Staff and Mr. Gorman (acting as joint witness for CUB and ICNU).

[34] See "The rate case process: establishing a fair return for regulated utilities", by RRA (a group within S&P Market Intelligence), June 29, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy 295-310.

1 **Q. Can Staff provide evidence of an industry-wide trend in authorized**
2 **capital structures?**
3 A. Yes. On July 22, 2020, RRA published its "Major Rate Case Decisions"
4 report for January to June 2020.[35]
5 RRA reported
6 To offset the negative cash flow impact of 2017 federal tax reform,
7 many utilities sought higher common equity ratios, and the average
8 authorized equity ratios adopted by utility commissions in 2019
9 were modestly higher than the levels observed in 2018 and 2017.
10 However, in cases decided during the first half of 2020, the
11 average authorized equity ratio for electric utilities fell to 48.61%.
12 For full years 2019, 2018 and 2017, the average equity ratios
13 authorized in electric utility cases were:
14 **Table 4[36]**
15 **RRA Summary of Authorized ROEs**

Average Equity Ratios (%) Authorized by Utility Commissions	2017	2018	2019	Q1,2 2020	PAC Proposed
	48.9	49.02	49.94	48.61	53.52

16 As illustrated in Table 4 above, PacifiCorp's proposed capital structure
17 including 53.52 equity is far higher than the industry norm, and would

[35] See "Major Rate Case Decisions" by RRA Regulatory Focus of S&P Global Market Intelligence. Reproduced in Exhibit Staff/1912, pages 467 – 472.
[36] Compiled by Staff. See Exhibit 1912, page 469 for data.

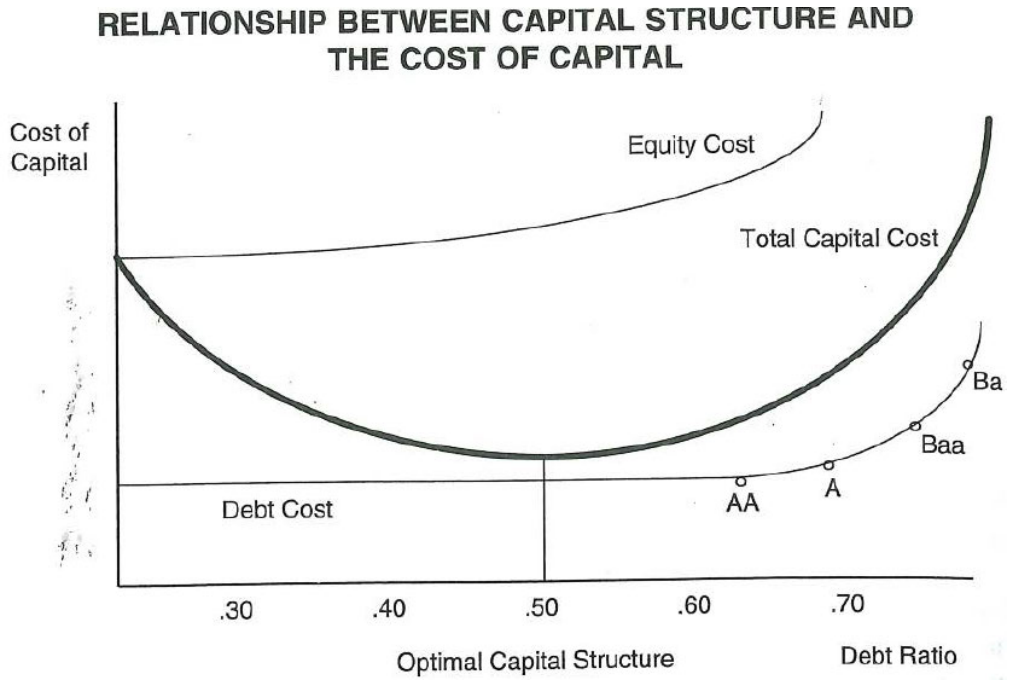
result in Oregon ratepayers paying much higher prices than ratepayers in other states.

Q. How does one choose an Optimal Capital Structure?

A. In regulation, an optimal capital structure is the blend of debt and equity that minimizes costs to ratepayers. Equity is more expensive than debt, however as a company relies more on debt, it is seen as more risky, putting pressure on its bond ratings and increasing its cost of debt.

The theory is that there exists an optimal blend of equity and debt to balance these competing forces, minimizing the CoC incurred by ratepayers.

Figure 6[37]



This theory is demonstrated in Figure 6 above, which depicts the Optimal Capital Structure choice in a famous finance textbook. The textbook

[37] See Figure 16-1, Chapter 16 "Weighted Average Cost of Capital" on Page 454 of "New regulatory Finance by Roger A. Morin, PhD 2006 Printing.

1 illustration of this presumes a 50 percent Common Equity and 50 percent LT
2 Debt, Capital Structure.
3 **Q. Does the fact that debt costs are currently near an all-time low affect**
4 **optimal capital structure?**
5 A. A drop in the cost of debt would make debt relatively cheaper and would shift
6 the optimal balance of debt and equity more to the equity side.
7 **Q. If a utility's finance group targets a 50 percent equity layer in Capital**
8 **Structure, will calculated Capital Structure stay right at that level?**
9 A. No. Issuing Common Stock in Public Markets or by other usual means can
10 be lumpy, in that some costs are similar to issue a large amount of stock as to
11 issue a lesser amount. But one would expect the utility that targets a
12 50 percent common equity layer in Capital Structure to oscillate up and down
13 around a 50 percent common equity, 50 percent LT Debt. Seven years ago,
14 an actual 52 percent equity layer in Capital Structure was accepted because
15 this was expected by Staff to be a temporary level that would revert to a
16 balanced 50 percent equity layer shortly.[38]
17 **Q. Did PacifiCorp's Capital Structure soon revert back to a 50 percent**
18 **equity layer?**
19 A. No. PacifiCorp is only now coming in for a GRC. In that intervening time, the
20 2017 Tax Act was passed into law. An odd consequence of that tax cutting
21 legislation was increased pressure on Moody's Funds from Operations (FFO)

[38] See "new Regulatory Finance", "Optimal Capital Structures Table 18-7 on Page 513."

and related credit metrics. A higher equity layer in capital structure makes it much easier to satisfy Moody's FFO type metrics.[39]

Q. PacifiCorp relies heavily on the FFO to Debt metric in its response. How does Staff respond?

A. In light of the Company's lower rating with Moody's than with S&P Global Market Intelligence (S&P), its focus on satisfying Moody's requirements is reasonable. However, Staff's finds that the Company has over-emphasized the importance of the FFO/Debt metric in its reply testimony.

The fact is that rating agencies include a variety of factors in their assessment of regulated utilities. Financial metrics account for 40 percent of a utility's rating, with other factors including regulatory framework, ability to recover costs and earn returns, and diversification playing a significant role.[40] For example, Moody's has identified "the geographic diversity of PacifiCorp's six-state service territory," and its "credit supportive relationships with the regulators in each of these states" as positive drivers of its credit rating.[41]

Moody's rating methodology for regulated electric and gas utilities is summarized in Figure 7 below.

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39 PAC/2100, Kobliha/2-3.

40 See "Regulated Electric and Gas Utilities Rating Methodology" by Moody's, June 23, 2017. Accessible at: www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1072530.

41 See "Moody's affirms PacifiCorp at A3, outlook stable", by Moody's Investor Service, June 20, 2020. Accessible at: https://www.moodys.com/research/Moodys-affirms-PacifiCorp-at-A3-outlook-stable--PR_385350.

Figure 7
Moody's Rating Methodology For Regulated Utilities[42]

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

Q. Financial metrics account for just 40 percent of the rating agencies assessment of the Company. Is FFO/Debt the most heavily weighted of the financial metrics?

A. Yes; however, although FFO/Debt[43] is the most heavily weighted financial metric evaluated by Moody's, it is not the only important metric. Moody's also assigns a heavy weight to "CFO pre-WC – Dividends/Debt" and "Debt/Capitalization," both metrics in which the Company performs well, given its dividend strategy and 52 percent equity layer.

[42] See "Regulated Electric and Gas Utilities Rating Methodology" by Moody's, June 23, 2017. Accessible at: www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1072530.

[43] Shown in Figure 7 as "CFO pre-WC / Debt".

1 **Q. How do Portland General Electric, Cascade Natural Gas, Avista**
2 **Corporation, and Northwest Natural Gas deal with the challenge of**
3 **managing to meet Moody's FFO?**
4 A. These other jurisdictional utilities, which have a balanced Capital Structure,
5 have to operate in an environment requiring more careful management. One
6 might think of a 53 percent Capital Structure as a plane almost able to fly
7 itself with minimal worries with regard to FFO, while a 50 percent or less
8 common equity layer requires careful management of financial tradeoffs.
9 **Q. Is it harder for PacifiCorp to manage its Capital Structure than the**
10 **aforementioned other jurisdictional energy utilities?**
11 A. No. Ms. Kobliha describes in part how PacifiCorp has a flexible dividend
12 policy and can use dividend payments as a tool to manage capital structure
13 and cash flow in times of growth cycles.[44]
14 In contrast, an Investor Owned Utility (IOU) with many investors including
15 money managers and institutional investors dependent on regular reliable
16 dividends lacks said flexibility in managing dividends to accelerate capital
17 spending.
18 **Q. Has PacifiCorp presented any evidence of its need for special**
19 **treatment in this regard?**
20 A. No. The Company presents no evidence to demonstrate that lower FFO/Debt
21 ratios in the future must be offset by a high equity level.

[44] PAC/2100, Kobliha/8.

1 For example, in spite of providing historic FFO/Debt values and forecasted
2 capital expenditures in its response to AWEC, the Company left blank the
3 cells in which it could have provided a forecast of the future FFO/Debt
4 ratios,[45] which they claim pose such a large concern.[46]
5 Further, the Company does not demonstrate how, or to what extent, a
6 higher equity level would compensate for a low FFO/Debt ratio; or address
7 the interplay between these and other rating metrics.
8 **Q. The Company warns in both its opening and reply testimony that the**
9 **2017 Tax Act may negatively impact its credit ratings. What is Staff's**
10 **position on this?**
11 A. The Company first warned of the 2017 Tax Act in its opening testimony,
12 stating "the negative impact to the Company's credit metric … has not yet
13 been fully realized."[47] In response to Staff discovery, the Company
14 clarified this statement, explaining that the effects of the pass-through of
15 tax benefits to customers in Oregon and Washington beginning in 2019,
16 and its continued deferrals in other states, had not yet been fully realized
17 in the rating agencies' reviews which used pre-2019 data.[48]
18 **Q. Does the 2017 Tax Jobs Act still represent a significant unknown risk**
19 **to the Company?**

---

45 PAC/2100, Kobliha/7.
46 PAC/2100, Kobliha/7.
47 PAC/300, Kobliha/14, lines 20 – 22.
48 See PacifiCorp's response to Staff Data Request 196.

1 A. No. The risk is not still unknown. The positive news, for both the Company
2 and customers, is that in the interval since the Company filed its reply
3 testimony both Moody's and S&P have reaffirmed PacifiCorp's positive
4 ratings based on its 2019 financial data.[49] In addition to this, PacifiCorp
5 was labelled as "Stable" by both S&P and Moody's, indicating each
6 agency's confidence in the given rating going forward. This is in addition
7 to the rating agencies maintaining the Company's ratings at their current
8 high levels since the enactment of the 2017 Tax Act three years ago.
9 Considering this gesture of ongoing support from the rating agencies,
10 and the fact that **[BEGIN CONFIDENTIAL]** [redacted]
11 [redacted] **[END CONFIDENTIAL]** in
12 their summer 2020 credit rating reviews of PacifiCorp,[50] Staff does not
13 expect the 2017 Tax Act stands to have a significant impact on the
14 Company's ratings going forward.
15 **Q. Does PacifiCorp already weigh impacts on utility customers in**
16 **targeting a Capital Structure?**
17 A. No. It falls to the Commission to balance the benefits of a higher than
18 50 percent equity layer of Capital Structure, which are well-described by Ms.
19 Kobliha in PAC/2100, against the higher than regionally typical incremental
20 costs to utility customers in the Test Year. The Commission is charged with

[49] See Exhibit Staff/1911, page 460.
[50] See Confidential Exhibit Staff/1912.

1 balancing the interests of shareholders with those of ratepayers in setting just
2 and reasonable rates.
3 **Q. Does Staff agree with PacifiCorp's assessment of AWEC's opening**
4 **testimony?**
5 A. No. PacifiCorp complains that AWEC has focused too significantly on the
6 Company's past capital structure, rather than on its forecasted capital
7 structure, and does not account for the thorough testimony and
8 calculations carried out to simulate the Company's capital structure as
9 interpreted by the rating agencies.
10 Further, PacifiCorp rejects Mr. Gorman's suggestion that the
11 Company's credit metrics may be expected to improve over time, as
12 imputed debt assessed to the Company by S&P falls. In response to
13 AWEC, the Company references its "incomplete" internal review of S&P's
14 most recent report, and "some percentage of new renewable resources"
15 being in the form of Power Purchase Agreements (PPA) (on which imputed
16 debt are assessed). Staff does not find that the Company has adequately
17 addressed the concerns of AWEC on this matter, in fact the Company
18 merely dismisses AWEC's, concerns without attempting to provide tangible
19 evidence to address them.
20

ISSUE 3 – STAFF'S UPDATED RETURN ON EQUITY (ROE)

Q. Has Staff updated its Return on Equity estimates?

A. Yes. Staff reviewed all the criteria for its peer screen and inputs into its models. After updating all parameters to reflect data available in early July 2020, Staff still recommends a required return of 9.0 percent.

PEER SCREEN

Q. Has Staff reviewed the peer group it uses in its modelling?

A. Yes. Staff performed a full review of the criteria[51] it had employed in opening testimony. This involved reviewing the following inputs for each utility: regulated percentage of each utility's operations, market beta, market capitalization, past dividends, dividend forecast, and capital structure.

Q. Have Staff or the Company made any changes to their peer groups in reply or rebuttal testimony?

A. Following a thorough review, Staff's deemed there to be no changes necessary to original screen of peer utilities.

PacifiCorp dropped one peer from its peer group in reply testimony, namely CenterPoint. This is likely due to the Company declaring a lower dividend Q2 2020 than its historic dividends. Staff has reflected this change to the Company's peers in the comparisons provided in this rebuttal testimony and supporting exhibits.

[51] As detailed in Staff/200, Muldoon-Enright/12 – 13.

HAMADA EQUATION

Q. Can you explain the purpose of the Hamada equation?

A. The Hamada equation is used to better compare companies with different capital structures. Essentially, the Hamada equation can be used to calculate adjustments to the required return if a company was to change its equity ratio, but keep its beta, tax rate, and all other parts of its risk profile the same. This Hamada adjustment can be simply added to an estimated return.

Q. How does Staff utilize the Hamada equation?

A. As another robustness check to its primary ROE models, Staff adjusts the equity ratio for all companies in the peer screen to match PacifiCorp's proposed equity ratio of 53.52 percent. Staff then adds the Hamada adjustment to the initial estimated returns from these models.

Q. Why is an adjustment using the Hamada equation necessary?

A. PacifiCorp has a very different target capital structure than many of the companies used in its peer screen. Although there are companies in the peer screen with both relatively higher and lower equity ratios that will offset each other, a Hamada adjustment ensures that Staff's recommendation is not unduly influenced by a biased up or down peer group.

THREE STAGE DISCOUNTED CASH FLOW (DCF) MODELS

Q. As a reminder, can you briefly describe Staff's Three-Stage DCF model?

A. Yes. In general, a DCF model assumes that a firm's required return can be determined by comparing its stock price against its future dividend flow. As a company grows, so should its dividend flow. In a single-stage DCF model, one assumes that dividends grow at a constant rate in perpetuity. This is a general approximation in "normal" economic times for a well-established company with a continuous dividend payout.

In contrast to a single-stage DCF model, a multi-stage DCF model assumes that dividends do not grow at a constant rate. Staff utilizes a three-stage DCF model, which means that a firm's dividends are expected to grow at one rate in the near term, another rate in the middle term, and grow at a third rate in perpetuity in the long term.

Q. Why does Staff believe that this added modelling complexity is necessary?

A. While using a three-stage DCF does add some modelling complexity relative to a single-stage DCF, it allows Staff to properly estimate a firm's required return during an abnormal economic environment without undue bias. The three stages of growth rates used by Staff reflect three distinct anticipated economic periods brought about by the COVID-19 pandemic:

1. A short-term period of abnormal growth as the world reacts to the pandemic,
2. A medium-term period where the world transitions from the pandemic-level growth to normal growth,
3. A long-term period that reflects normal economic growth.

Staff believes that using other common modelling techniques employed by PacifiCorp (risk return models, CAPM, single-stage DCF and ECAPM) don't properly capture the monumental economic shock caused by the COVID-19 pandemic.

Therefore, Staff chooses to use only two variants of the three-stage DCF model to determine required returns, and utilizes other models merely as robustness checks.

Q. Has the Commission traditionally relied heavily on a Three-Stage DCF model when making Cost of Capital decisions?

A. Yes. The Commission has a history of using a Three-Stage DCF model to formulate recommendations for authorized returns in rate cases. Even though the three-stage DCF model forms the basis of our recommendations, Staff has used CAPM and single-stage DCF models to ensure the quality of our recommendations. Staff continues to use these two models in this rate case, and their use will be discussed further in this testimony.

Q. What other modelling choices have Staff made?

A. Much like in our opening testimony, Staff has chosen to run two separate models to estimate required returns, which are referred to as Model X and Model Y. In Model X, Staff estimates required returns by assuming that an investor holds the stock in perpetuity, and its value is based on its dividend payouts. In Model Y, the investor sells the stock after 30 years, and its value is derived from its growth in Earnings Per Share (EPS), as well as the

1 dividends.[52] Additionally, Staff adjusts all estimated returns using a Hamada
2 equation before making any recommendations for PacifiCorp. The latter
3 addresses difference in capital structure and corrects for varying amounts of
4 borrowing or leverage.

5 **Q. What changes have been made to the Model X and Model Y in Staff's**
6 **initial testimony and Staff's rebuttal testimony?**

7 A. The only changes made between Staff's initial testimony and current
8 testimony, have been to update available data. Staff incorporated the
9 Quarter 2 2020 Value Line reports for companies in the peer screen, which
10 represent the most up-to-date data currently available.

11 **Q. What growth rate and time period does Staff use to model the first**
12 **stage?**

13 A. Staff's first stage runs from 2020 to 2024, reflecting the period directly
14 affected by the COVID-19 pandemic. This stage uses company-level
15 projected dividend growth rates and EPS growth rates from Value Line
16 available to model the growth rate.

17 For Model X, Staff assumes that companies paid out the dividends
18 reported on their most recent Value Line report in 2020 and 2021. Staff then
19 estimates the payouts for 2022, 2023, and 2024 by taking Value Line's
20 expected dividend payout in 2023-2025, and assuming dividends grow at the
21 same rate from 2021 through 2025. Staff employs the same method for

[52] Please refer to Staff's Opening Testimony for a more complete discussion of Staff's modelling choices. See Staff/200, Muldoon-Enright/20-22.

Model Y, but supplements reported and estimated dividends with reported and estimated EPS.

Q. What growth rate and time period does Staff use model the second stage?

A. Staff assumes that the second stage runs from 2024 through 2029. The growth rate is projected to smoothly transition from each company's short run growth rate used in the first stage, to the shared long-run growth rate used in the final stage.

Q. What growth rate and time period does Staff use model the final stage?

A. Staff chose to model final stage's growth to begin in the year 2030. This reflects the economy returning to its normal level in the year 2030. Industry experts agree that this is a reasonable timeline for recovery.[53] Staff runs separate versions of its model, using various long-run economic growth rates from a variety of sources to conduct this analysis. These include:

- The Congressional Budget Office's long-term growth projection of 3.70 percent.
- A weighted blend of projected 20-year nominal growth rates from Energy Information Administration, PriceWaterhouseCooper, Social Security Administration, Fidelity, and the Congressional Budget Office, and the

[53] See "Economy Setback Seen Taking 10 Years to End" by by Paul Kiernan and Paul Hannon in the Wall Street Journal, reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/34 – 36.

real historical GDP growth from the Bureau of Economic Analysis, combined with a TIPS inflation forecast. This blend results in a rate of 3.94 percent.[54]

- The BEA's real historical GDP growth combined with the TIPS inflation forecast. Summing these two together results in an expected growth rate of 4.38 percent.
- The growth rate used in PacifiCorp's opening and reply testimony of 5.05 percent.

As discussed above, Staff's model assumes that the long-term growth rate continues in perpetuity in Model X. In Model Y, this growth rate instead continues until 2049 when the stock is sold and the investor benefits from stock price appreciation as well as the flow of dividends

Q. Are the updates from Value Line and the updated growth rates sufficient to capture the dramatic changes in the economy due to the COVID-19 Pandemic?

A. Yes. Staff's recommendations are based on the best available information at this time. For example, Value Line's most recent reports were compiled well after COVID-19 was declared an international pandemic by the WHO and lockdowns went into effect in the US.

The long-term growth rates used in Staff's analysis were also updated post-lockdown where possible. Post-lockdown, Staff was able to add another

[54] The weights used to create this blend are demonstrated in Exhibit Staff/1904.

period of BEA data to calculate long-term GDP growth, the CBO updated its long-term growth rate, and the FED updated its inflation target. While it is hard to say what the full extent of the damage of the COVID-19 pandemic will be, Staff's long-term growth rates are likely overly-optimistic which may overstate Staff's estimated authorized ROE.

Q. How have these growth rates changed between Staff's initial testimony and Staff's rebuttal testimony?

A. In the blended long-term growth rate described above, Staff has added a long-term GDP growth forecast from Fidelity. All other changes are due to more recent data becoming available.

Q. What is the result of Staff's analysis using a three-stage DCF model and a Hamada adjustment?

A. Using the Staff's peer screen, the Hamada adjustment and the composite long-term growth rate outlined above, Staff's models X and Y calculate a required ROE of 8.19 percent and 8.45 percent respectively. Staff has used the Hamada-adjusted results from Model Y as a reasonable lower bound for an authorized ROE for PacifiCorp.

When the composite long-term growth rate is replaced with the growth rate used in Bulkley's reply testimony, Staff's models X and Y calculate a required ROE of 9.13 percent and 9.30 percent – both of which fall within Staff's range of reasonable ROEs. Staff has used the Hamada-adjusted results from Model Y (9.30 percent) as a reasonable upper bound for an authorized ROE for PacifiCorp.

Staff then adds 12.50 basis points to each of these bounds to account for common stock flotation costs, to arrive at a reasonable authorized ROE between 8.57 percent and 9.42 percent. The midpoint of this range is 9.00 percent, which was Staff's initial authorized ROE recommendation.

The results of Model X and Model Y are presented in Exhibit 1904, using the growth rates mentioned above. Staff also includes results without a Hamada adjustment, and with the Company's peer screen, for transparency.

Q. Do you have any other evidence to support the reasonableness of this range?

A. Yes. Staff's analysis using a single-stage DCF model and CAPM also point to the upper end of this range. Additionally, Mr. Gorman's testimony on behalf of AWEC recommends an authorized ROE of 9.2 percent, within a similar range.[55]

Q. Has Staff revised its final recommendation?

A. No, Staff still recommends an ROE of 9.0 percent. Staff still believes that the range defined by the high and low values presented above constitute reasonable returns.

Q. Does Staff believe that this recommendation satisfies the requirements outlined by the *Hope* and *Bluefield* standards?

A. Yes. All analyses done by Staff points to 9.0 percent being enough of a return to reward investors and reflect the PacifiCorp's risk profile. Staff found

[55] AWEC/200, Gorman/2.

no evidence to motivate anything higher than an ROE of 9.42 percent, much less PacifiCorp's recommended ROE of 10.2 percent.

Any authorized return above 9.42 percent would overcompensate investors and ensure excellent access to capital market rates.

ANALYSIS COGNIZANT OF MARKET CONDITIONS & OTHER JURISDICTIONS

Q. What does Staff do to ensure that it remains cognizant of market conditions and other jurisdictions?

A. Staff makes a habit of keeping up to date on news from sources in finance, economics and the utility industry. Staff regularly reads the Wall Street Journal and industry magazines, and stays up to date on the newest data releases to time series in the Federal Reserve Bank of Louis (FRED).

Q. What news sources does Staff use and what information does Staff get from these news sources?

A. Staff utilizes a variety of news sources including the Wall Street Journal, Yahoo Finance, Utility Dive, the Oregonian, Moody's, S&P Global Market and news and data releases from government agencies.

Among other things, Staff receives information on the health of the economy and various submarkets. These have been particularly helpful to judge the magnitude of the COVID-19 pandemic and its effects on the economy.

Q. In a previous section of testimony, Staff said that the COVID-19 pandemic has made projecting into the future difficult. Has this changed how has Staff used its news sources than in the past?

A. No. Staff does concede that the ongoing pandemic does make available information harder to interpret due to future uncertainty. However, Staff prides itself in using the most up-to-date information that it has available and incorporating it where appropriate like it always has. In this way, Staff has been able to keep up with industry trends that are relevant to the agency's operations.

Q. Are there any sources that have been particularly helpful in keeping up with industry-relevant trends?

A. Yes. The Federal Reserve Bank of St. Louis (St. Louis FRED) keeps an ongoing database of various time series. Staff routinely checks the yields on US treasury bonds, stock returns, and GDP growth. These have been particularly helpful in creating the models we use for setting rates. Staff has also used S&P Global Market Intelligence's Regulatory Research Associates (RRA) as a source for trends specific to utility regulation.

Q. Do any independent observers report on industry-wide trends in authorized ROEs?

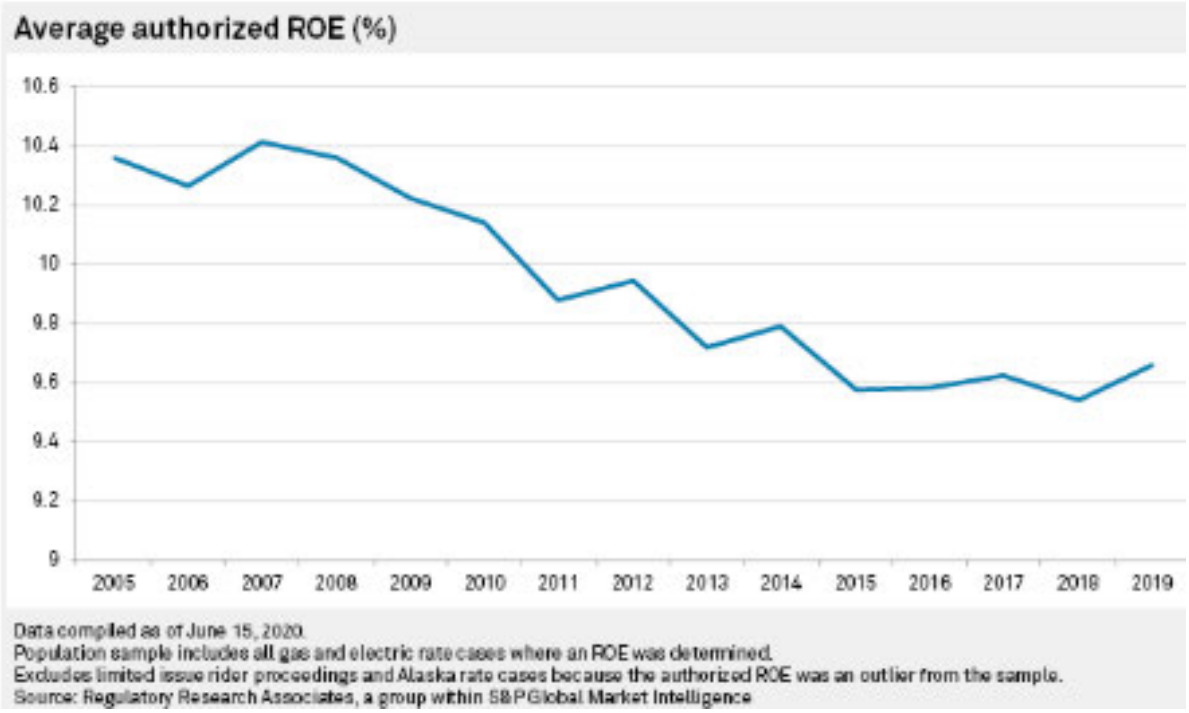
A. Yes. On July 22, 2020, RRA published its "Major Rate Case Decisions" report for January to June 2020. In its report, RRA reported that excluding

limited-issue riders,[56] the average authorized ROE for electric utilities in the first six months of 2020 was 9.47 percent, down from 9.64 percent in full year 2019. The average authorized ROE for gas utilities was 9.40 percent in the first half of 2020, a fall from 9.71 percent in full year 2019. [57]

Q. What other reports from RRA have been informative to Staff?

A. The RRA recently published an article discussing the methods that public utility regulators use to set required returns for electric and gas utilities. In their article, RRA demonstrates that average authorized returns have been

Figure 8[58]



56 Limited-issue riders are ROE premiums allowed in certain states to address the recovery of specific generation projects.

57 See "Major Rate Case Decisions" by RRA Regulatory Focus of S&P Global Market Intelligence. Reproduced in Exhibit Staff/1912, pages 467 – 472.

58 See "Deep Dive into ROE Methodologies Reveals Much Lies below the Surface" by Dan Lowrey, S&P Global Market Intelligence – Jun. 29, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/53 – 55.

falling for the last decade and are around 9.4 percent in 2020. This value is well below PacifiCorp's proposed authorized return of 10.2 percent. Figure 8 above presents how authorized returns have fallen in recent years.

ISSUE 4 – GREEN FIRST MORTGAGE BONDS (FMB)

Q. How did the Company respond to Staff's opening testimony regarding green bond issuance?

A. The Company discussed the costs and benefits of green bond issuance, stating that "only tangible benefit of issuing a green bond is increased orders from funds with green or environmental, social, and governance requirements."[59] The Company indicated that it would continue to evaluate green bond issuance each time it goes to the market.

Q. Why is the Company's cautious approach, in waiting for proven and initially realizable cost savings, not the prudent course of action?[60]

A. PacifiCorp notes there are incremental costs for starting any new financial offering. Whether one is issuing in private placement or issuing green bonds, there is the need to create and legally review new agreements, forms and documents, increasing legal cost for the first new issuance. Then there are new processes and procedures to work out, consuming time and other finite resources.

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[59] PAC/2100, Kobliha/9.

[60] PAC/2100, Kobliha/9.

1 But starting today, that initial hurdle is overcome, allowing next issuances
2 to be routine and cost effective. Otherwise, the initial difficulties will keep a
3 cost barrier from allowing the Company to move forward for some time.

4 **Q. Why does Staff recommend the Commission convey a sense of**
5 **urgency in PacifiCorp's issuance of Green FMB?**

6 A. PacifiCorp is entering a massive build cycle. Much of that capital spending is
7 on renewable generation such as new or upgraded wind and solar
8 generation, associated storage, and transmission with supporting substations,
9 as well as the refinancing of debt for like renewable purposes.

10 This means that PacifiCorp is about to finance projects that can make a
11 difference in global climate change, and that provide alternatives to thermal
12 generation of electricity.

13 Further, issuers can borrow more cheaply through a green bond than a
14 plain-vanilla vehicle thanks to broader demand, with various studies and
15 industry bodies observing savings of up to 30 bps,[61,62,63,64] along with a "halo
16 effect" for an issuer, pushing down yields across their bond portfolio.[65] The
17 bond market is much bigger than the equity market, but the ability to deploy

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[61] See "Have corporate green bonds offered lower yields?", by MSCI Research, March 10, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/110 – 112.

[62] See "Emerging-Market Green Bonds Are In Demand", by Craig Mellow – Barron's, July 2, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/70 – 71.

[63] See "Green bond finance and certification", in Bank of International Settlements Quarterly Review, September 2017. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/311 – 326.

[64] See "Investors may pay 'greenium' as green bond demand outstrips supply", by S&P Global Market Intelligence, March 28, 2018. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/133 – 135.

[65] Id.

capital sustainably is much more limited. Considering the financial benefits achievable, and the Company's high capital needs in the coming years, green bond issuance presents a cost saving opportunity for the Company and its customers.

Q. Can Staff provide a specific example of an investment for which the Company could issue green bonds?

A. Easily. Just this month, PacifiCorp issued a request for proposals seeking 4.3 GW of renewable energy and battery storage. This represents the largest RFP in the utility's history, and one of the largest calls for renewables in the industry.[66]

PacifiCorp's RFP has been named "historic" by industry experts, as it is both "the biggest, and the first RFP aimed at replacing coal-fired generation". It would truly be a shame for PacifiCorp to initiate a renewable building program of this magnitude, without having an operational green bond program in place to finance its transformational effort.

Q. Barron's says that the green bond market was only $200 billion dollars as of last year, so why not wait until it becomes more prevalent?[67]

A. Barron's also notes that the market grew by 25 percent last year. Private borrowers and institutions are looking for investment in actual sustainable

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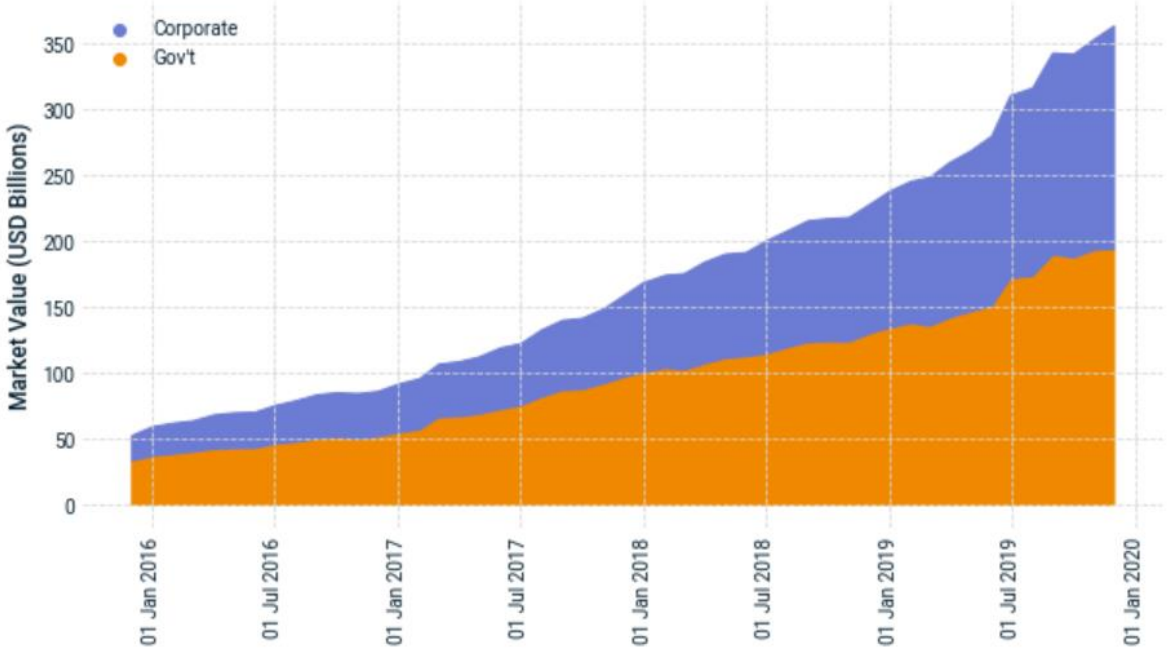
[66] See "PacifiCorp Launches Historic RFP for Renewables", by Steve Ernst, Clearing Up, July 10, 2020. Reproduced in Exhibit Staff/1911, pages 37 – 39. Muldoon-Enright-Dlouhy/

[67] Id.

energy. It can be hard for banks, insurance companies, and other entities to explain how their company is making a sustainable difference, while reducing the risk of green washing. PacifiCorp's planned green investments over the coming years will allow it to position itself as a reliable "green" issuer in this booming market. Figure 9 below demonstrates the rapid growth of the market for green bonds in recent years.

Figure 9[68]
Booming Growth in Green Bonds Market



Source: Bloomberg Barclays MSCI Global Green Bond Index, MSCI.

Q. Do processes at the Commission in which PacifiCorp already engages have the potential with minor changes to create a free superior three-part certification for Green FMB?

[68] See "Have corporate green bonds offered lower yields?", by MSCI Research, March 10, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/110 – 112.

A. Yes. In Integrated Resource Planning (IRP), the Commission already acknowledges renewable projects and other capital spending to enable renewable penetration and integration.

Next, PacifiCorp explains the intended uses of funds in its financing applications with the Commission.

Finally, in GRCs or like proceedings, PacifiCorp demonstrates that renewable and enabling facilities are energized, used and useful.

In aggregate, these processes could assure investors that:

- PacifiCorp is authorized for renewable build in the near future,
- Financing is authorized for said uses and refinancing of like instruments, and
- The projects were constructed and used to deliver the intended benefit.

Staff sees no stronger green certification or program that could provide investors and money managers with greater certainty that their investment has their targeted effect.

Q. If the Company's underwriters can fill a PacifiCorp order book in 30 minutes, is a formal Green FMB program necessary?[69]

A. Yes. There is a big difference between intending to act when the time is right and routinely identifying green tranches if FMB, working with the Commission,

[69] PAC/2100, Kobliha/4.

1 Investment Banks, Rating Agencies, and others to create a normal process in
2 which the next issuance no longer has the initial setup costs.
3 The result is potentially higher demand leading to savings for the
4 Company and ratepayers, while delivering solid green securities that
5 investors and money managers will be proud to hold.
6 **Q. Has anyone in the Berkshire family of utilities successfully started**
7 **and now routinely rely on a Green FMB program?**
8 A. Yes. MidAmerican Energy Company has shown that it can on a regular
9 ongoing basis issue Green FMB in the same form, through most of the same
10 banks, and with a program to satisfy some of the need of local Iowa investors
11 desire to hold securities that make a sustainable difference.[70]
12 MidAmerican Energy has also overcome the issues of size of green
13 tranches of bonds, and started to offer securities that investors and money
14 managers particularly want. In addition to their investment value, such bonds
15 also have a Communication Value.
16 **Q. What do you mean by Communication Value?**
17 A. As global advertising spend approached $560 billion in 2019, much of this
18 was spent on communicating sensitivity to social and environmental issues.[71]

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[70] See statement by MidAmerican Energy regarding its recent Green Bond issuances, accessed on July 15, 2020. Accessible at: https://www.midamericanenergy.com/green-bonds#:~:text=MidAmerican%20Energy%20is%20committed%20to%20using%20natural%20resources,energy%20resources%20in%20Iowa.%20Why%20Issue%20Green%20Bonds%3F.

[71] See "Global advertising spending from 2010 to 2019", by A. Guttmann of Statista, January 8, 2020. Accessible at: https://www.statista.com/statistics/236943/global-advertising-spending.

In issuing green securities, both the utility and investors benefit from the communications value created.

One can see at a glance MidAmerican Energy's communication value that invites those interacting with its websites and other messaging to see the Company through a positive lens. The holders of the securities also are afforded the opportunity to communicate their contribution to issues that matter to themselves and their customers.

Q. How does Moody's see proactive sustainable investment measures?

A. Moody's tends to see inclusion of sustainable finance in business planning Credit Positive.[72] This offers one constructive alternative to a higher equity layer in Capital Structure for maintaining credit ratings with Moody's.

Q. What is Staff's recommendation to the Commission on this matter?

A. Staff urges the Commission to act with and convey a sense of urgency for PacifiCorp's development of an ongoing Green FMB program.

Staff also suggests that the Commission may want to work with the Company to translate current processes already in place to generate Commission Orders that include green certifications appropriate for use in bond issuance, and acceptable to investment banks, insurance companies, credit rating agencies, and large money managers.

Going forward, Staff intends to monitor issuances of green bonds in debt markets, paying particular attention to yields achieved on such bonds, to

[72] See "German Banks' Collective Commitment on Climate Action is Credit Positive," by Christina Holthaus and Carola Schuler of Moody's Investors' Service, July 6, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/32 – 33.

1 inform its determination of the prudence of LT Debt issuances in future GRCs

2 and other proceedings before the Commission.

1 **ISSUE 5A – STAFF RESPONSE TO INTERVENORS – OTHER THAN AWEC**

2 **Q. What parties, other than the AWEC, PacifiCorp, and Staff provided**
3 **Opening Testimony regarding PacifiCorp's CoC?**

4 A. Multiple other parties addressed CoC at least briefly in Opening Testimony
5 in the PacifiCorp GRC, including Walmart, Klamath Water Users
6 Association (KWUA), the Sierra Club, and the Citizens' Utility Board (CUB).
7 Staff responds here to each of their testimonies individually.

8 **Q. What was the recommendation of Walmart on the CoC?**

9 A. Walmart recommends that the Commission consider the welfare of the
10 ratepayers when selecting a proper ROE.[73]

11 **Q. What were the Company's thoughts regarding the work of Walmart's**
12 **witness, Mr. Chriss?**

13 A. PacifiCorp noted that Mr. Chriss did not perform any ROE analysis. He did
14 review some materials by RRA, which the Company noted were useful
15 information, but generally inadequate to inform the Commission in
16 comparison to more intensive study of market conditions and ROE
17 modeling.[74]

18 **Q. Does Staff agree with Walmart's recommendation that the**
19 **Commission should consider the Company's proposed ROE increase**
20 **in light of the resulting impact on customers?**

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[73] Walmart/100, Chriss/6-11.
[74] PAC/2200, Bulkley/117-119.

A. Yes, to the extent legally permissible. During these unprecedented times of the COVID-19 outbreak, many ratepayers have lost their jobs or have diminished job security, and find themselves struggling to pay bills on time. ROE is often expressed as a range of reasonable potential outcomes. Authorizing an ROE at the higher end of the range would boost PacifiCorp's free cash flow to the firm at a time when electricity consumers find themselves challenged to pay their current rates. Moreover, as PacifiCorp enters a period of large capital spending on utility infrastructure, each new project could be more expensive than appropriate, as inflated costs lead to a higher total recoverable costs. It is therefore reasonable for Walmart to ask the Commission to balance the needs of customers against those of the Company to find just and reasonable rates.

Q. Does Staff Agree with PacifiCorp that declining utility prices in comparison to utility earnings will inevitably lead to higher authorized ROEs?[75]

A. No. That is unsupportable conjecture. As a simple counter, referent long-run GDP growth rate estimates from a variety of sources are falling since Staff's Opening Testimony. That in combination with historical low US Treasury (UST) Bond yields suggest a continuation of falling authorized ROEs.

Q. What was the recommendation of KWUA on the CoC?

[75] PAC/2200, Bulkley/119.

A. KWUA recommends that the Commission reject the 10.2 percent ROE that was originally proposed by PacifiCorp and further lower their ROE from its current level of 9.8 percent.[76]

Q. How did PacifiCorp receive Mr. Reed of KWUA's recommendations?

A. The Company did not agree with Mr. Reed's thinking. PacifiCorp points out that Mr. Reed does not perform his own analysis and suggest that his logic is not consistent with the work PacifiCorp and its witnesses have done in this GRC. However, the Company had no good counter to Mr. Reed's observation that both a 40 bps increase to PacifiCorp's currently authorized ROE, and indeed PacifiCorp's currently authorized 9.8 percent ROE, are both unjust and unreasonable values for current authorized ROE, in particular when balanced with current hardships being experienced by KWUA members.[77]

Q. Does Staff agree with KWUA's assessment?

A. Yes, in part. As discussed in Staff's opening testimony, Staff believes that PacifiCorp's authorized ROE of 9.8 percent is abnormally high for current market conditions in Oregon, especially when compared to its peers and the downward trends of regulators reducing the authorized ROE in GRCs over the last decade.

Q. What trends do Staff refer to?

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[76] KWUA/100, Reed/23-27.

[77] PAC/2200, Bulkley/120-121.

A. A June 29, 2020, article by S&P described the methodology used by regulators to select the optimal authorized required ROE.[78] Within this article, the author presents a plot of the average annual authorized ROE each year since 2005. Within this plot, one can observe a downward trend in the authorized ROE. The peak occurs in 2007 with an average authorized ROE of 10.4 percent, and the authorized ROE has been trending downward since. 2012 was last year in which the average authorized ROE was above PacifiCorp's current level of 9.8 percent. The graph of this trend was previously presented in Figure 8.

Q. What does CUB recommend regarding PacifiCorp's capital structure?

A. CUB recommends that the Commission factor into account Oregon's high unemployment when choosing a proper authorized ROE for PacifiCorp. CUB cites that a regulator's duty is to balance the profitability of the regulated companies against the welfare of citizens in its jurisdiction. In light of the COVID-19 pandemic, Oregon entered a deep recession that caused unemployment to spike to 21 percent and it is expected to stay above 10 percent for years to come. As a result, CUB argues that extra emphasis should be given to ensuring that consumers are charged a fair rate.[79]

Q. Does the Company concur?

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[78] See "Deep Dive into ROE Methodologies Reveals Much Lies below the Surface" by Dan Lowrey, S&P Global Market Intelligence – Jun. 29, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/53 – 55.

[79] CUB/100, Jenks/35-36.

1 A. No. The Company points out that Mr. Jenks makes general statements
2 which are not specifically addressed to CoC or components thereof.[80]
3 Further, PacifiCorp disagrees that its PCAM reduces risk for the
4 Company. Ms. Bulkley goes on to repeat in conclusion that PacifiCorp's
5 ability to attract capital to finance investments at reasonable rates is
6 predicated on her recommendations.[81] However, in no part of her
7 testimony does she demonstrate that were PacifiCorp to receive from the
8 Commission Staff's or AWEC's recommendations, even tempered further
9 by heightened consideration of impact on customers as recommended by
10 CUB, that PacifiCorp would be unable to attract capital at reasonable rates
11 to finance planned utility investments.
12 **Q. Does Staff agree with CUB's assessment?**
13 A. Yes, to the extent legally permissible. Consumers are already feeling
14 constrained by their utility bills. This can be seen by the skyrocketing
15 amount of unpaid utility bills and the Utility Shut-Off Moratorium enacted by
16 29 states and voluntarily enacted by utilities in another 17 states.[82,83]
17 **Q. Please summarize the recommended ROE by Mr. David B. Posner on**
18 **behalf of the Sierra Club.**

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80 PAC/2200, Bulkley/122 – 123.

81 PAC/2200, Bulkley/124.

82 See "Virus could push unpaid utility bills to highest level in decades", by By Mark Chediak and Gerson Freitas Jr of Bloomberg, May 11, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/30 – 31.

83 See "Summary of State Utility Shut-off Moratoriums due to COVID-19", June 18, 2020. Accessible at: https://neada.org/utilityshutoffsuspensions/.

1 A. Mr. Posner recommends that PacifiCorp be allowed a 9.8 percent ROE,
2 which appeared to be a recommendation for a 50 bps increase in ROE
3 because Mr. Posner of the Sierra Club seemed to indicate PacifiCorp's
4 current authorized ROE is 9.30 percent. Conversely, there could be a
5 typological error and Mr. Posner is recommending that the Commission
6 reauthorize PacifiCorp's current 9.80 percent ROE. Mr. Posner also
7 addresses capital structure, but for Staff it was a bit muddled and drew on
8 unsupportable assumptions and relationships.

9 **Q. What analysis did Mr. Posner conduct on the issue?**

10 A. Mr. Posner did not conduct an analysis on ROE when he determined that
11 9.8 percent ROE is adequate. He did cite that UST bond yields have been
12 lower since the onset of the COVID-19 pandemic, and that capital
13 spending on renewable projects is being rewarded with higher valuations
14 and a lower ROE.

15 **Q. How did the Company react to Mr. Posner's recommendations**
16 **regarding ROE and Capital Structure?**

17 A. The Company appreciated Mr. Posner's 9.8 or higher ROE, but did not agree
18 with the logic behind Sierra Club's CoC proposed findings.[84]

19 **Q. What is your response to this analysis?**

20 A. Mr. Posner's analysis on ROE is inadequate to support his ROE
21 recommendation and produces a result that is not substantiated by

[84] PAC/2200, Bulkley/114-117.

industry trends or the recent COVID-19 outbreaks. Additionally, his statements on the low UST bond yields is inaccurate. As discussed by S&P article introduced above, the ROE should take long-term UST bond yields into account in a Capital Asset Pricing Model (CAPM) as a proxy for the risk-free interest rate. Lowering the risk-free rate will lower the required CoC. UST Bond yields have been at an all-time low since March, indicating that the authorized ROE for PacifiCorp should be lowered accordingly.

For reasons discussed later in this testimony, Staff does not use CAPM when setting rates. However, CAPM does provide an intuitive way for one to discuss the link treasury yields and desired returns.

ISSUE 5B – STAFF RESPONSE TO INTERVENORS – AWEC

Q. Did AWEC provide Opening Testimony regarding PacifiCorp's CoC?

A. Yes. Michael P. Gorman provided opening testimony on behalf of AWEC regarding PacifiCorp's CoC.

Q. What CoC issues did Mr. Gorman address in his opening testimony?

A. AWEC's comprehensive testimony provided recommendations to the Commission on PacifiCorp's capital structure, LT Debt, return on common equity, and overall ROR.

AWEC's testimony also provides an overview of recent financial trends in the utility sector, supported by historic evidence drawn from financial

1 markets. This included testimony on capital costs for utilities, their access
2 to capital, trends in credit ratings, and market outlook.
3 Mr. Gorman pays particular attention to the need to meet the
4 Company's financial needs at the lowest possible cost to customers.[85]
5 **Q. Please summarize AWEC's recommendations.**
6 A. AWEC's recommendations are as follows:
7 - Capital structure to include 50.64 percent equity.
8 - LT Debt costs should reflect issuances in April 2020.
9 - ROE of no higher than 9.2 percent.
10 - Overall ROR of 7.01 percent.
11 **Q. What recent financial trends for regulated utilities did AWEC**
12 **highlight?**
13 A. Mr. Gorman's testimony provides an extensive review of financial trends
14 affecting regulated utilities. He began by noting that authorized returns
15 tend to follow capital market costs, and then demonstrated a trend of
16 declining authorized returns on equity for electric and gas utilities over the
17 past fifteen years, stabilizing at the mid-9 percent range over the past five
18 years.[86] This trend is widely said to mirror falling market capital costs.
19 Next, Mr. Gorman illustrated how the industry has experienced a
20 marked improvement in its overall financial health and credit quality in

[85] AWEC/200, Gorman/2.
[86] AWEC/200, Gorman/4 – 5.

recent years, with electric utility bond ratings trending upward since 2009. In addition to this, PacifiCorp is among the industry's most strongly rated utilities in the U.S. followed by Value Line.[87] Mr. Gorman points to the fact that recent credit downgrades of electric utilities have been driven by factors not relating to regular electric utility operations. An example of this is PG&E's large wildfire damage liability, and the California experiment with inverse condemnation, wherein an electric utility can be deemed responsible for starting a fire in California if its equipment is at least somewhat related to the fire, even if there is no negligence on the part of the California utility.[88]

Another very positive market trend highlighted by Mr. Gorman is the ongoing ability of regulated electric utilities to raise finance for capital expenditures in the past decade, paired with robust valuations of utilities, which are a strong indication of their ability to raise capital at reasonable terms, relatively low cost, even in challenging market conditions.[89]

Finally, Mr. Gorman provides an overview of the flattening of the yield curve, the repeated lowering of the Federal Funds Rate through 2019 and 2020, and the historically low long-term interest rates which are expected to persist at least over the next several years.[90] This ensemble of

[87] AWEC/200, Gorman/6 & 21.
[88] AWEC/200, Gorman/5 – 6.
[89] AWEC/200, Gorman/7 – 8.
[90] AWEC/200, Gorman 12 – 14.

information supports his view that market participants are comfortable with lower capital market costs, and expect them to prevail over at least the intermediate period.[91]

Q. Did Mr. Gorman offer any observations regarding the 2017 Tax Act?

A. Yes. Mr. Gorman states that the effects of the 2017 Tax Act have already been reflected in market offerings and bond ratings.[92] Since that event was three years ago, this is a reasonable position. One anticipates that markets assimilate new information fairly rapidly.

This contrasts with the Company's opening and reply testimony, in which advises that the 2017 Tax Act is still a big unknown, which has the potential to adversely affect the Company's financial position.[93]

Q. Does PacifiCorp agree with Mr. Gorman's assessment?

A. No. In her testimony on behalf of PacifiCorp, Ms. Bulkley notes that since 2017 Tax Act was passed, the Moody's credit ratings for many regulated utilities has fallen.[94] Yet Staff notes that ratings for some utilities who have managed their metrics well have risen since the 2017 Tax Act. That appears to be a material omission in PacifiCorp's narrative.

Q. Which assessment does Staff believe is more accurate?

A. Mr. Gorman's testimony is far more compelling. Ms. Bulkley's testimony highlights only the utilities whose credit ratings fell following the 2017 Tax

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91 AWEC/200, Gorman/17.
92 AWEC/200, Gorman/6.
93 PAC/2200, Bulkley/34.
94 PAC/2200, Bulkley/35, Figure 11.

1 Act, and paints an overly-pessimistic picture of its effects. One would
2 almost think the 2017 Tax Act was an ominous future event rather than a
3 fading event from some time ago.
4 Mr. Gorman on the other hand, presents the bond ratings of all
5 regulated utilities, demonstrating that the credit ratings of utilities have
6 actually been trending upward since 2009. In 2017, 83 percent of
7 regulated utilities had a BBB+ credit rating or higher. By 2020, that
8 number had risen to 86 percent.[95]
9 Mr. Gorman's position is further strengthened by the positive news
10 reported in Staff's rebuttal testimony on this issue – Both S&P and Moody's
11 affirmed the Company's existing credit ratings since the Company filed its
12 reply testimony.
13 This recent rating, which uses 2019 financial data, was identified by
14 the Company through discovery as being an indicator of the effects of the
15 2017 Tax Act.[96] In addition to the reaffirmed ratings, the agencies include
16 "Stable" and "Not on watch" labels, which reflect their confidence that
17 PacifiCorp will receive the same rating going forward.
18 **Q. Does Mr. Gorman address the effect of COVID-19 on the financial**
19 **health of utilities?**

[95] AWEC/200, Gorman/6, Table 1.
[96] See PacifiCorp's response to Staff Data Request 196.

A. Yes. Witness Mr. Gorman presents recent publications from each of the three large rating agencies. The overall message being presented is that the downside risk of COVID-19 is expected to affect only "a few outliers and those issuers already facing downside ratings pressure."[97] Mr. Gorman observes that overall, "utilities are expected to weather the economic downturn caused by the pandemic, and their financial strength will be restored as the economy recovers."[98]

Q. Does AWEC's perspective on the effects of COVID-19 tally with that of Staff?

A. Much like Mr. Gorman, Staff recognizes that COVID-19 represents a big unknown both to the US and world economies. Further, it represents a challenge to small businesses and utility customers who are currently experiencing hardships which have likely never been seen by this generation. To borrow Mr. Gorman's words, we should "be especially concerned about rate impacts on the service area economies that are severely constrained due to the current economic conditions."[99]

Experts at Moody's recently singled out PacifiCorp's **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as factors driving their expectation

[97] AWEC/200, Gorman/9, in which Mr. Gorman quotes a statement by S&P Global Ratings.
[98] AWEC/200, Gorman/10.
[99] AWEC/200, Gorman/11.

1 that the Company will be **[BEGIN CONFIDENTIAL**[redacted]
2 [redacted] **[BEGIN CONFIDENTIAL]** related to COVID-19.[100]
3 Utilities have long been considered one of the safest assets for
4 investors,[101] attracting capital at the most reasonable rates.[102] Staff's view
5 tallies with that of market experts - this fundamental truth of financial
6 markets is unlikely to change, despite increased market volatility.[103]
7 In fact, the demand of utility customers is far less elastic than other
8 products, as evidenced by the extensive academic literature on estimating
9 electricity demand elasticity.[104,105] Classic papers find that while electricity
10 use does increase with income, consumer electricity consumption is very
11 inelastic as well.[106] This means that regardless of economic conditions
12 brought about by the COVID-19 pandemic, total electricity consumption
13 should change relatively little. Consequently, the utility industry is likely to

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100 See Confidential Exhibit Staff/1912, page 1.

101 AWEC/200, Gorman/11.

102 See "Tech and Utilities Stocks Both Rally in Polarized Market" by Akane Otani of WSJ, February 21, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/288-289.

103 See "Safe Utilities Have Been More Volatile Than Broader Stock Market" by Anna Hirtenstein – WSJ – June 24, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/184-187.

104 See Lijesen, M. G. (2007). The real-time price elasticity of electricity. *Energy economics*, *29*(2), 249-258. and Borenstein, S. (2009). Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/455-464.

105 See "To what electricity price do consumers respond? Residential demand elasticity under increasing-block pricing", Preliminary Draft April, 30, 95. for an introduction into the literature in electricity demand elasticity estimation. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/354-391.

106 See Branch, E. R. (1993). Short run income elasticity of demand for residential electricity using consumer expenditure survey data. *The Energy Journal*, *14*(4). Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/393-403

emerge from the COVID-19 period in better financial health than many others.

Q. What is Staff's response to the current financial market trends affecting utilities, as presented by AWEC?

A. Staff found AWEC's presentation to be very thorough and informative, and agrees with AWEC that US utility companies, particularly those with the financial strength of PacifiCorp, are currently in a very strong position to raise capital at favorable rates.

Staff believes that Mr. Gorman's observations merit considerable weight by the Commission in its decision-making.

Q. Please summarize AWEC's recommendation regarding PacifiCorp's capital structure.

A. AWEC found the Company's proposed capital structure to be "more expensive than necessary," and found that the Company had "failed to justify that a 53.52 percent common equity ratio of total capital is needed to support its credit rating, financial integrity and access to capital."[107]

AWEC recommended the following capital structure:

Table 5
AWEC's Proposed Capital Structure

LT Debt	49.35%
Preferred Stock	00.01%
Common Equity	50.64%
Total Capital Structure	100.00%

[107] AWEC/200, Gorman/21.

1 **Q. AWEC uses a historic "Adjusted Debt Ratio" to support its proposed**
2 **capital structure. Please explain this approach.**
3 A. AWEC's approach is mindful of PacifiCorp's concerns, specifically the
4 need to satisfy the financial ratios of rating agencies, which include
5 adjustments for debt-like liabilities such as short-term debt (ST Debt) and
6 off-balance sheet (OBS) debt equivalents.
7 Accounting for both ST Debt and OBS in addition to PacifiCorp's
8 regular LT Debt, Mr. Gorman calculates the Company's historic "Adjusted
9 Debt Ratio" for the period 2014 through 2018, as ranging from 48.78
10 percent to 51.48 percent.[108]
11 Mr. Gorman contrasts this against the Company's proposed capital
12 structure, which once adjusted for OBS and other debt, and excluding
13 unexplained increases in projected OBS,[109] reflects a drastically low
14 adjusted debt ratio of 46.5 percent.
15 Mr. Gorman argues that as an adjusted debt ratio ranging from 49 to
16 50 percent was sufficient to support PacifiCorp's "A" credit rating and
17 "Stable" outlook in the past, that it would be an appropriate range for the
18 Company's capital structure going forward. Consequently, Mr. Gorman
19 takes mid-point of this range, backing out the OBS and ST Debt
20 adjustments, to calculate a recommended capital structure of 50.64
21 percent common equity debt to 49.35 percent LT Debt.

[108] AWEC/200, Gorman/22.
[109] AWEC/200, Gorman/24.

1 **Q. What is Staff's opinion of Mr. Gorman's "Adjusted Debt Ratio"?**

2 A. Although the calculations made by Mr. Gorman involve some estimation,
3 his point is valid. Further, given that PacifiCorp has stressed the
4 importance of credit ratings so fully in its testimony, Staff finds it
5 appropriate to address the calculations made by the credit agencies, and
6 how the Commission's decisions in this case may affect those ratios.

7 Mr. Gorman's approach of providing actual historic data and projected
8 calculations contrasts with the Company's voluminous testimony about its
9 "need" for a higher equity tranche to support its credit rating, without
10 providing any specific information on the ratios and how they are applied.

11 **Q. Is there anything remarkable about PacifiCorp maintaining an "A"**
12 **rating and "Stable" outlook with an adjusted debt ratio in the 49 to**
13 **50 percent range?**

14 A. Not at all. As demonstrated in Table 6 of Mr. Gorman's testimony,[110] half of
15 regulated utilities with an "A" credit rating have an adjusted debt ratio of 51.5
16 percent. Mr. Gorman's recommendation is generous in comparison.

17 **Q. Would the Commission approving a common equity ratio of 50.64**
18 **percent cause a shock to financial markets or to the industry?**

19 A. No. Mr. Gorman's recommendation of 50.6 percent common equity is
20 reasonable, and would be viewed as such by the industry. Further, it is in-

[110] AWEC/200, Gorman/26, Table 6.

1 line with the electric industry norm, for which the average common equity
2 ratios in the decade ending Q1 2020 was 50.2 percent.[111]
3 As a final bit of evidence, as Mr. Gorman notes that the average
4 authorized common equity ratio for regulated electric utilities in the United
5 States is 50.24 percent.[112]
6 **Q. What other evidence does Mr. Gorman use to support AWEC's**
7 **proposed CoC?**
8 A. Mr. Gorman uses his proposed ROE of 9.2 percent and capital structure
9 consisting of 50.64 percent common equity to create three pro forma
10 financial ratio predictions: FFO to Total Debt; Debt to Earnings Before
11 Interest, Taxes, Depreciation, and Amortization; and Total Debt to Capital.
12 He demonstrates that these new predicted ratios result in no change to the
13 recommended risk category according to S&P guidelines.[113]
14 **Q. Does PacifiCorp have any criticisms of Mr. Gorman's analysis? If so,**
15 **what are they?**
16 A. In her testimony, Ms. Bulkley disagrees that Mr. Gorman's proposed
17 capital structure and ROE are sufficient to support the Company's current
18 bond rating.[114] She notes that a large part of the Company's credit rating
19 is derived from the regulatory setting, and that Mr. Gorman's testimony
20 assumed PacifiCorp would always earn the authorized ROE. Finally, she

[111] AWEC/200, Gorman/28, Table 7.
[112] AWEC/200, Gorman/28, Table 7.
[113] AWEC/2200, Gorman/62 – 63.
[114] PAC/2200, Bulkley/72.

notes Mr. Gorman's proposed ROE for PacifiCorp is 9.2 percent, while the average authorized ROE for vertically integrated utilities from January 2018 through May 2020 is 9.7 percent, and that investors would be reluctant to invest in PacifiCorp if their authorized ROE is lower than peers with comparable risk factor.[115]

Q. Is Ms. Bulkley even remotely accurate in the above assessment?

A. Staff thinks that Ms. Bulkley's criticisms of Mr. Gorman intentionally leave out two very critical facts. First, as has been pointed out multiple times, the authorized ROE for regulated utilities has been falling consistently since 2009. As was pointed out in Figure 1 of Mr. Gorman's testimony, the average authorized ROE for regulated electric utilities in the year 2020 has so far been 9.45 percent.[116] Ms. Bulkley inaccurately claims that Mr. Gorman is proposing a monumental change in ROE when in reality, Mr. Gorman's recommendation closely follows industry trends.

Second, Ms. Bulkley ignores the financial security PacifiCorp enjoys by being a subsidiary of Berkshire Hathaway. In PacifiCorp's June 25, 2020 credit opinion, PacifiCorp was issued an A3 long-term rating.[117] Among the Company's key strengths, Moody's listed that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[118] A July 7, 2020, credit report by S&P

[115] PAC/2200, Bulkley/110.
[116] AWEC/200, Gorman/4, Figure 1.
[117] See Exhibit Staff/1911, page 465.
[118] See Exhibit Staff/1912, page 2.

in which PacifiCorp was given an A rating[119] also notes that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** [120] This alone sets PacifiCorp apart from its peers and makes PacifiCorp significantly less risky than the peers alluded to in Ms. Bulkley's testimony.

Q. Did AWEC address the Company's cost of LT debt?

A. Yes. AWEC recommended that the Commission require the Company to update its cost of LT debt calculation to reflect the $1 billion debt issuance which occurred following its opening testimony in April 2020.

This recommendation mirrors Staff's recommendation of a cost of LT debt of 4.82 percent, a value, which reflects the Company's latest debt issuances.

Q. What was Mr. Gorman's recommended ROE and how did he arrive at that recommendation?

A. Mr. Gorman recommended that PacifiCorp's authorized ROE be lowered from 9.8 percent to 9.2 percent.[121] He came to that recommendation by noting that there is a downward trend in authorized Returns on Equity for regulated gas and electric utilities, and corroborating these downward trends by modeling PacifiCorp's required ROR four separate ways:

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[119] See Exhibit Staff/1911, page 465.
[120] See Exhibit Staff/1912, page 12.
[121] AWEC/200, Gorman/2.

1. A Discounted Cash Flow (DCF) model,[122] calculated using two alternative growth rate projections;
2. A Multi-Stage DCF model;
3. A Risk Premium Model; and
4. A Capital Asset Pricing Model (CAPM).

Q. Please describe the inputs to Mr. Gorman's Single-Stage DCF Model.

A. For peer utilities, Mr. Gorman uses the same proxy group as PacifiCorp proposed. His inputs include the stock price, expected growth rate, and expected dividend, which are calculated as follows:

- Stock prices calculated as the average of the weekly high and low stock prices, over a 13-week period.
- Dividend growth rate of 5.25 percent, calculated as the average forecasted growth rates from: Zach's, MI, and YAHOO Finance.
- Long-term sustainable growth rate, which is represented by the Blue Chip GDP growth rate forecast of 4 percent. This growth rate is presented as an alternative growth rate to the dividend growth rate.
- Expected dividend calculated as the most recent quarterly dividend, multiplied by four quarters, and increased by the growth rate.

Q. How does Staff view the inputs used by Mr. Gorman in his Single-Stage DCF model?

[122] Note that Staff refers to the "Constant-Growth" DCF model as a Single-Stage DCF model.

A. As detailed under Issue 3, Staff does not agree with the peer group used, as the peer companies are clearly *more* risky on average than PacifiCorp. For example, Mr. Gorman recognizes that the peer group has an average credit rating two notches below PacifiCorp,[123] representing that they are riskier companies. Further, the peer group includes companies, which have recently completed or planned mergers, presenting problems with the reliability of historic and forecasted data for the companies.

Staff agrees with AWEC's approach of sourcing growth rates from a number of providers to reflect a broad set of investor expectations, nevertheless, as demonstrated in Exhibit Staff/1904, Staff prefers to use reliable government sources for the growth rates in its models.

Q. What are Mr. Gorman's constant-growth DCF estimates using these proxy groups and expected dividend growth rates?

A. Mr. Gorman's model shows average and median constant growth DCF returns of 9.18 percent and 9.19 percent, which he finds to be "a reasonable high-end return estimate."[124]

Mr. Gorman also presents the results of his Single-Stage DCF model using the expected long-term sustainable growth rate, yielding an estimated required ROR with a mean of 8.53 percent and median of 8.20 percent.[125]

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[123] AWEC/200, Gorman/32.
[124] AWEC/200, Gorman/36.
[125] AWEC/200, Gorman/35 & 38.

1 **Q. How did PacifiCorp react to Mr. Gorman's Single-Stage DCF model**
2 **methodology?**
3 A. Ms. Bulkley disagreed with Mr. Gorman's modelling choices for several
4 reasons:
5 • Ms. Bulkley finds Mr. Gorman's reliance on median DCF estimates
6 inappropriate, given that some utilities have ROEs below 7 percent.
7 Instead, she advocates that Mr. Gorman consider the mean of only
8 utilities whose ROEs exceed 7 percent, saying that this will more
9 accurately represent the market by omitting obvious outliers on the
10 low end.[126]
11 • Ms. Bulkley believes that the dividend yields used by Mr. Gorman
12 are irreparably broken, because of the higher stock price of publicly
13 traded utilities as a result of COVID-19.
14 • Finally, Ms. Bulkley believes that Mr. Gorman's growth rates do not
15 accurately reflect economic conditions. This appears to reflect an
16 aversion on Ms. Bulkley's part to a variety of long-term, 20-year
17 growth rates, which have all been revised downward recently.
18 **Q. Does Staff believe that Ms. Bulkley's method of excluding only**
19 **abnormally low estimated ROEs is appropriate?**
20 A. No. Ms. Bulkley's suggestion only considers abnormally low returns, but
21 does nothing to address any excessively large returns. By omitting only

[126] PAC/2200, Bulkley/74.

1 the low estimates, Staff is concerned that the resulting mean authorized
2 ROE could be unfairly biased upward.
3 **Q. Does Staff agree with Mr. Gorman's methods to address abnormally**
4 **low ROE estimates?**
5 A. Yes. While Ms. Bulkley's method of eliminating only the lowest ROE only
6 take weight away from the lowest estimated required returns, considering
7 the median value ensures that neither overly high nor overly low estimated
8 required returns get factored into the presented statistic.
9 As an example, suppose that 19 companies all have an estimated
10 return of 9 percent, but a single company's required return is estimated to
11 be 99 percent, which is obviously far too high of an ROE to be considered
12 relevant. In this case, it should be apparent that a 9 percent return is
13 standard for this industry. Employing Ms. Bulkley's method would result in
14 a mean return of 13.5 percent. However, Mr. Gorman's approach of
15 weighting the median results in a more representative return of 9 percent.
16 In this way, Mr. Gorman's treatment of the median value accounts for
17 estimates that are both too low and too high.
18 **Q. What is a sustainable growth rate?**
19 A. A sustainable growth rate accounts for the proportion of earnings, which
20 are retained and reinvested in the utility, growing the utility's rate base, and
21 increasing profits over time.
22 **Q. What are the results of Mr. Gorman's Sustainable Growth Rate DCF**
23 **Model?**

A. Mr. Gorman observes a sustainable growth rate of 4.62 percent among the peer group, which equates to an average return of 8.53 percent, and median return of 8.2 percent amongst the peer group using a DCF model.

Q. How did PacifiCorp react to Mr. Gorman's Sustainable Growth Rate DCF model?

A. Ms. Bulkley's criticisms about the sustainable growth DCF model were in response to Mr. Gorman's choice of a sustainable growth rate. Without citation, Ms. Bulkley notes that some academics support the theory that earnings growth may not occur alongside the retention ratio. She also notes that the by using Value Line's earned ROE, Mr. Gorman is pre-supposing an ROE that has a higher mean than the estimated required return of companies in the proxy group.[127]

Q. What is Staff's opinion of the sustainable growth rate DCF Model?

A. As has previously been stated, Staff only uses single-stage DCF models as a robustness check and only puts weight on the multi-stage DCF models when conducting its analysis. However, Staff agrees with Mr. Gorman's choice of a sustainable growth rate. It has also been previously noted that Staff takes issue with the proxy groups chosen by both Mr. Gorman and Ms. Bulkley.

Q. What is a Multi-Stage (Three Stage) DCF Model?

[127] PAC/2200, Bulkley/75-76.

A. A Three-Stage DCF Model is very similar to a Constant-Growth DCF Model, however, rather than assuming dividends grow at the same rate forever, a Three-Stage DCF model assumes that dividends have a short-term growth rate that differs from a long-term growth rate. A full discussion of a Three-Stage DCF model can be found in Staff's opening testimony.[128,129]

Q. What conditions would make a Three-Stage DCF model more appropriate than a single-stage DCF model?

A. In general, a Three-Stage DCF model is more appropriate when analyzing new companies or companies that are in the middle of some unprecedented change in their industry or individual company. A modeler would assume that this new or upheaved company would experience an abnormal growth in the near future, then transition from abnormal growth to a normal industry growth rate, and ultimately return to a normal growth rate for the industry in the long run.

Mr. Gorman, Ms. Bulkley, and Staff all discuss the massive industry upheaval caused by the COVID-19 pandemic. Therefore, a Three-Stage DCF seems like a perfect model to utilize as the world transitions back to normalcy.

Q. How do the inputs to Mr. Gorman's Three-Stage DCF model differ from the inputs to his single-stage model?

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[128] Staff/200, Muldoon-Enright/20 – 21.
[129] Note that that Staff refers to the "Multi-Stage" DCF model as a Three-Stage DCF model.

A. Mr. Gorman calculates the initial dividend payout and the stock price using the same method and same proxy group as for his Single-Stage DCF model. However, he uses three differing growth rates in his Three-Stage DCF model:

- The dividend growth rate of 5.25 percent, which was used in the single-stage model, is applied for the initial five year period.
- The long-term sustainable growth rate, which was used as an alternative growth rate in the single-stage model, is used from year 11 into perpetuity.
- A transition period growth rate is applied for years six through 10, and is calculated using a combination of the short and long term growth rates.

Q. Please summarize the results of Mr. Gorman's Three-Stage DCF model.

A. Mr. Gorman finds that the mean and median required returns for his proxy group are 8.23 percent and 8.28 percent, respectively.[130]

Q. Mr. Gorman uses forecasted GDP growth as a proxy for a utility's long-term sustainable growth rate, stating that "utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services."[131] Does Staff agree?

[130] AWEC/200, Gorman/45.
[131] AWEC/200, Gorman/39.

A. Yes. In our initial testimony and our update rebuttal testimony, Staff's long-term growth rate projection reflects a combination of projected GDP forecasts from government agencies and other industry experts much like Mr. Gorman does in his modelling. In his testimony on behalf of AWEC, Mr. Gorman also notes that utility sales growth has been lagging behind GDP growth estimates for more than a decade. Therefore, using expected GDP growth rates should form reasonable high-end estimates for required returns.[132]

Q. How did PacifiCorp react to Mr. Gorman's Three-Stage DCF model methodology?

A. Ms. Bulkley objects to Mr. Gorman's long-term growth rate of 4.0 percent, believing it to be too low. Ms. Bulkley notes that the finance community supports the use of historic real GDP growth rates paired with expected inflation rates when projecting long-term growth.[133]

Q. For Ms. Bulkley to be correct, would a half dozen of the primary financial forecasting agencies of the U.S. Government have to be wrong?

A. Yes. For Ms. Bulkley to be accurate on growth rates, would mean that the Federal Agencies shown in Exhibit Staff/1904 Muldoon-Enright-Dlouhy/1 would necessarily have to be wrong in their recent updates of 20-year, long-run GDP growth rates.

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[132] AWEC/200, Gorman/40.
[133] PAC/2200, Bulkley/78.

1 **Q. Does PacifiCorp agree with Mr. Gorman's results?**

2 A. No. In her reply testimony, Ms. Bulkley is very critical of Mr. Gorman's
3 approach, in spite of it being consistent with virtually all the U.S.
4 government entities tasked with maintaining long-run GDP growth rates.

5 **Q. What is a Risk-Premium Model?**

6 A. A Risk-Premium model assumes that investors will only invest in a riskier
7 company if the expected return is higher. It allows an investor to break
8 down a company's required ROE into two separate components: the
9 market's risk-free rate and an estimated risk premium.[134]

10 **Q. What was the result of Mr. Gorman's risk premium model?**

11 A. Mr. Gorman's model indicated a return in the range of 8.8 percent to
12 9.5 percent.

13 **Q. What has the Commission's view of the Risk Premium model been to**
14 **date?**

15 A. The Commission has rejected the risk premium model numerous times,[135]
16 whilst also recognized that it can be used as a tool to help "gauge the
17 reasonableness of the ROE estimates derived from independent
18 methodologies."[136]

19 Nevertheless, Staff maintains that the risk premium approach works
20 best when one is in a level, stable pattern of returns. This is contrary to

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[134] See Docket No. UG 366, Staff/1100, Muldoon-Enright/26 – 38, for further discussion of the Risk Premium model.

[135] As detailed in Docket No. UG 366, Staff/1100, Muldoon-Enright 31 – 32.

[136] See Docket No. UE 115, Order No. 01-777, pages 33 - 34.

the volatility that has been experienced in financial markets in recent months, and as a result, Staff rejects the results of the risk premium model at this time.

Q. Please describe the CAPM.

A. CAPM is similar to a Risk-Premium model in that it assumes that a stock's ROE is a function of a risk-free return and a risk premium. Unlike a Risk-Premium Model, CAPM assumes that the risk premium should be augmented by a company's level of risk relative to the market, which is captured by beta.[137]

Q. Please describe the inputs to Mr. Gorman's CAPM.

A. His inputs include the risk-free rate, PacifiCorp's beta, and both a historical and forward-looking market risk premium.

- Risk-free rate is represented by Blue Chip's projected yield on 30-year UST bonds, which is 1.8 percent.
- Beta is represented by the long-term average utility beta estimates from Value Line for his proxy group, which average approximately 0.69 percent.
- Historical Market Risk premium, calculated as the arithmetic average historical real market of return of 8.8 percent, compounded by a projected inflation rate of 2.1 percent, less the risk-free rate, resulting in a risk premium of 9.28 percent.

[137] See Docket No. UG 347, Staff/1300, Muldoon Watson/31 – 39, for further discussion of CAPM ROE Modeling, and the Commission's historical treatment of CAPM results.

- Forward-looking Market Risk premium, calculated as the difference between historic S&P returns, and nominal UST bond returns, which is 6 percent.[138]

Q. Does Staff agree with Mr. Gorman's choice of model inputs?

A. While there are some minor discrepancies between Staff's and Mr. Gorman's respective CAPM inputs, particularly in relation to his peer group, Staff has no objections to Mr. Gorman's modelling choice. Like Mr. Gorman, Staff relies on Value Line as its sole source of beta estimates for its CAPM. Staff uses the most-recent daily yield on 30-year UST bonds of 1.326 percent, while Mr. Gorman uses analysts' forecasted yield of 1.8 percent. This is a minor difference, and Staff finds Mr. Gorman's choice of a risk-free rate to be fair.

Mr. Gorman's methods of finding the risk premium also differ from the method used by Staff. Unlike Mr. Gorman, Staff found the risk premium by subtracting the spot rate for 30-year UST bonds from the average S&P return 1989-2019 of 9.51 percent. While Staff believes that its method is most appropriate, Staff takes no objection to Mr. Gorman's method of using longer-term real S&P yields, nominal CPI growth projections, and projected 30-year UST Bond yields.

Q. What were the results of Mr. Gorman's CAPM estimation?

A. Mr. Gorman's two separate market risk premium estimates yielded estimated required returns for PacifiCorp of 5.95 percent and 8.24 percent.[139]

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[138] AWEC/200, Gorman/57.
[139] AWEC/200, Gorman/59.

1 **Q. How do Mr. Gorman's estimated returns compare to Staff's most-**
2 **recent estimated returns using CAPM?**
3 A. Since updating our Value Line beta estimates and 30-year UST yields, Staff's
4 CAPM yielded a mean required return of 7.5 percent using the Company's
5 screen. This is well within the 5.95 - 8.24 percent range estimated by Mr.
6 Gorman. As has been stated before, Staff believes CAPM to be a useful
7 robustness check for the reasonableness of a rate but chooses instead to rely
8 on a multi-stage DCF model in this rate case. For the purpose of validating
9 other modelling techniques, Staff believes that Mr. Gorman's CAPM methods
10 and estimates are sound.
11 **Q. Please summarize Mr. Gorman's overall recommended ROR.**
12 A. Mr. Gorman recommends that PacifiCorp be authorized a 7.01 percent
13 overall ROR. He arrived at that number by using PacifiCorp's current
14 outstanding debt along with his recommended return on common equity
15 and capital structure.
16 **Q. What is your overall assessment of Mr. Gorman's work on CoC?**
17 A. Mr. Gorman offers a solid complement to Staff's analysis wherein the
18 combination of AWEC and Staff modeling and recommendations provides
19 a solid foundation for the Commission to approve just, reasonable, and fair
20 rates that continue to ensure PacifiCorp retains excellent access to capital
21 at reasonable cost.

1 **ISSUE 6 – STAFF RESPONSE TO BULKLEY'S REPLY TESTIMONY**
2 **IN PAC 2200**

3 **Q. Is PacifiCorp's Summary Overview Point 1 reflective of current market**
4 **conditions?[140]**

5 A. No. Ms. Bulkley accurately notes falling U.S. Treasury (UST) bond yields to
6 near historic lows, but it is not accurate in depicting continued volatility and
7 high spreads in the U.S. investor grade utility bond and UST markets.

8 **Q. What are current yields, spreads and volatility now like for UST and**
9 **A- and B-rated US utility bonds?**

10 A. The spread between A- and B-rated US treasury bills and US utility bonds
11 has reached a four-month low. In fact, it can be easily seen that the
12 spread has nearly reached pre-COVID-19 levels. On top of that, the
13 decrease in the spread has been stable and not nearly as volatile as Ms.
14 Bulkley depicts it in her testimony.[141] We refer back to Figure 2 to
15 demonstrate this and encourage Ms. Bulkley to do further research on the
16 bond market before making any further claims.

17 **Q. What is the implication of very low bond yields, relatively low**
18 **spreads, and minimal volatility over the foreseeable future?**

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140 PAC/2200, Bulkley/3.
141 See "Investment-Grade US Corporate Spreads Hit Four-Month Low – Risk Monitor" by Peter Brennan – S&P Global Market Intelligence – Jul. 8, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/118-122.

1 A. Those are the conditions generally attributed to a decade long trend in falling
2 utility commission authorized ROEs.[142] If those conditions are back, then it is
3 likely that the falling trend in authorized ROEs is also back.

4 **Q. Have Value Line Beta Coefficients risen as noted in Summary 2?[143]**

5 A. Yes, Value Line Beta Coefficients have risen markedly. While a utility stock
6 usually has a fairly low volatility compared to other stocks in the market,
7 meaning the utility stock is more stable and less responsive to the news of the
8 day, currently IOU stocks are moving about almost as much as other stocks
9 in the S&P 500 Index in response to news about COVID 19 cases and other
10 day to day changes in information investors are seeing.[144]

11 However, that is not all great news for utility stocks. Volatility or shifting
12 about in price does not necessarily mean consistently rising prices. Indeed
13 as one looks at 2020 Second Quarter (Q-2) results by sector of the S&P 500,
14 one has to go way down the list to get to the much less than S&P 500 Index
15 returns for Q2.[145] This can be seen in Figure 5 on page 17 of this testimony.

16 **Q. Has Ms. Bulkley made a case to support rising authorized ROEs for**
17 **IOUs?**

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[142] See "Deep Dive into ROE Methodologies Reveals Much Lies below the Surface" by Dan Lowrey of S&P Global Market Intelligence – Jun. 29, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/53-55.

[143] See PAC/2200, Bulkley/3.

[144] See "Safe Utilities Have Been More Volatile Than Broader Stock Market" by Anna Hirtenstein of WSJ – June 24, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/184-187.

[145] See "Track the Market – Winners and Losers for 2020 Q2" – WSJ – Jul. 1, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/223-227.

A. No. Her information is materially inaccurate regarding spreads and volatility in IOU bonds and UST yields.[146] Volatility in fixed income is diminishing, while volatility in equities has risen. Ms. Buckley fails to correctly read Staff's Opening Testimony in that regard. That flaw entirely undermines the foundation of Ms. Bulkley's argument. Instead, one would expect actual fixed income conditions and mediocre Q2 IOU stock returns to strongly indicate that we have returned to a falling glide path for authorized IOU ROEs

Q. Will this falling trend in ROEs continue for some time to come?

A. Yes. If the U.S. Federal Reserve and other referent entities are correct, then this trend may continue for between 2 and 10 years, somewhat reflective of the period of time that Chairs Bernanke and Yellen oversaw historically low and stable interest rates.[147]

Q. Regarding PacifiCorp Summary 3, is PAC's Proposed 10.2 percent ROE reasonable in any way?[148]

A. No. As PacifiCorp emphasizes, ROE modeling should generate reasonable results but PacifiCorp's modeling generates absurdly high results making the results incompatible with both governing law and precedent.

Q. Does PacifiCorp provide sufficient evidence to rebut Staff's and AWEC's positions?

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[146] See PAC/2200 Buckley/29.

[147] See "Fed Plans to Keep Rates at Low Level for Years" by Nick Timiraos – WSJ – Jun. 11, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/81-82.

[148] PAC/2200, Bulkley/4.

1 A. No. Staff and AWEC perform analysis that is consistent with Commission
2 policy and precedent. Staff's rebuttal testimony will demonstrate how
3 unnecessary uncertainties and assumptions can be used to inflate otherwise
4 reasonable findings outside the range of all reasonable present expectations
5 in Oregon.

6 **Q. PacifiCorp suggests that its business and financial risks are immense in**
7 **Oregon, and that this requires incremental return to offset said risks. Is**
8 **that accurate?[149]**

9 A. No. Staff does not see PacifiCorp's business as particularly risky; AWEC has
10 also not provided any evidence in support of this conclusion. Instead, they all
11 agree with senior Berkshire Hathaway leadership that this is a great strategy
12 for Berkshire to stay rich and get richer. PacifiCorp's suggestion it faces
13 immense risks in Oregon contradicts Warren Buffet's and Charlie Abel's
14 speeches at the most recent annual BRK shareholders meeting.[150]

15 **Q. Does PacifiCorp undertake any risky investments that distinguish it**
16 **from its peers?**

17 A. No. PacifiCorp reasonably looks to whether the Company is riskier than its
18 peers, but fails to recognize that is not the case. While PacifiCorp is building
19 wind plants, a mature technology, peer utilities are building far riskier offshore
20 wind plants and dealing with nuclear issues. Moving toward renewables is a

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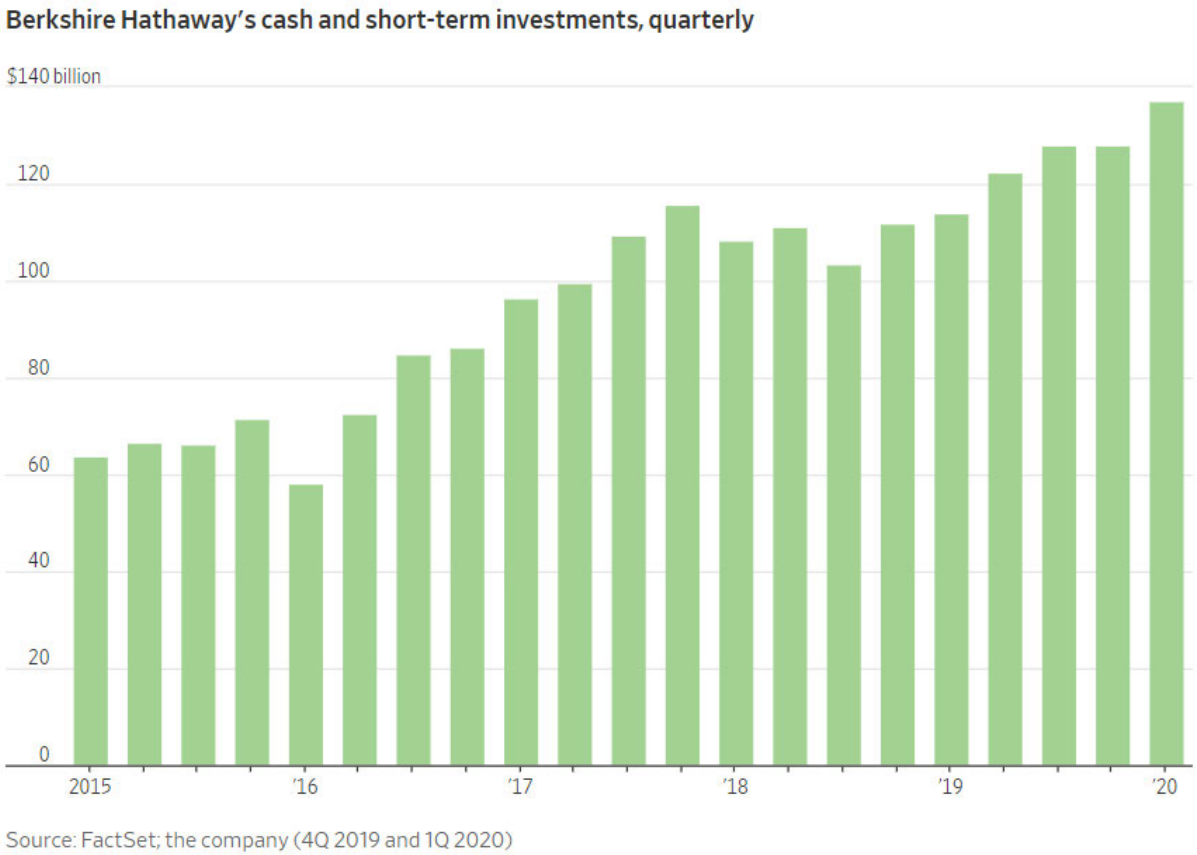
149 PAC/2200, Bulkley/4
150 See Staff/200, Muldoon-Enright/33-34 for further discussion of Staff's observations of BRK's recent Annual Shareholder Meeting.

1 profitable and relatively low risk growth model, answering the question of how
2 utilities will address shareholder desire to see growth.
3 As was demonstrated above, Staff was not convinced by Bulkley's
4 argument that PacifiCorp is more risky than its peers, particularly when using
5 Staff's strict credit screen in place of PacifiCorp's loose credit screen. Staff
6 further believes that Bulkley fails to address whether PacifiCorp is less risky
7 than its peers, an equally important question required by governing law.
8 **Q. Is PacifiCorp less risky than its Peers?**
9 A. The answer to that question is likely yes, particularly if one included peers
10 with only an investment grade credit rating in their screening.
11 Moreover, PacifiCorp has clarified that it has good control over its dividend
12 policy and can harness cash flows for growth purposes better than at least
13 some peers, further reducing its risk.[151]
14 Finally, as covered with some fascination by financial news, PacifiCorp's
15 parent company BRK is cash rich and opportunity poor. BRK, and has
16 recently been holding something just short of $140 billion earning miniscule
17 returns on UST, and has been eager for some relatively low risk, highly
18 certainty investment in utility capital spending. Considering such spending is
19 currently earning a 7.621 percent ROR, providing capital for PacifiCorp's new
20 investments represent an arbitrage opportunity to earn over 5.5 percent
21 higher rates than waiting about in UST.

[151] See PAC/300, Kobliha/5 – 6.

1 It is also worth noting that Berkshire Hathaway has shown a recent affinity
2 for investment into energy, as evidenced by a $4 billion investment in
3 Dominion Energy's natural gas pipeline. Despite this, Berkshire Hathaway's
4 cash holding grow by approximately $4 billion per month.[152] PacifiCorp
5 should have no problem attracting investment from its uber-wealthy parent
6 company.

7 **Figure 10[153]**



[152] See "Power Play" by Joshua Funk and J. Paschke – AP, Oregonian – Jul. 17, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/290.
[153] See "Warren Buffet's Berkshire Hathaway Reports $49.7 Billion Loss for First Quarter" by Geoffrey Rogow – WSJ – May 2, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/40 – 42.

1 **Q. Does ample cash have anything to do with business risk of financial**
2 **distress?**
3 A. If an entity has enough money to deal with whatever emergency or
4 contingency comes its way, that entity that may require fewer guarantees like
5 letters of credit, bonds guaranteeing conformance to contracts and so on. A
6 given setback could be inconvenient, but likely would not involve a bankruptcy
7 filing.
8 **Q. How does Staff have confidence that its peer utilities are of similar risk**
9 **to that of PacifiCorp?**
10 A. Staff's screening for close credit ratings to PacifiCorp ensures that Staff's
11 peers bear similar financial risk to PacifiCorp in the opinion of Moody's and
12 S&P. This is just one of the examples in this testimony of why Staff's screen
13 methods are much more efficacious than that of the Company.
14 **Q. In Ms. Bulkley's fourth summary statement, she says that her**
15 **adjustments to Staff's and AWEC's modelling do not support Staff's**
16 **and AWEC's ROE recommendations. How does Staff respond to**
17 **this?[154]**
18 A. When the errors are removed from the Company's modeling, results are
19 indeed highly supportive of both Staff's and AWECs recommendations
20 regarding capital structure and ROE.

[154] PAC/220, Bulkley/4.

Q. How does Staff respond to Ms. Bulkley's criticism in Summary 5 that Staff does not update its models to reflect current market conditions and relies too heavily on DCF models?[155]

A. The Company states that Staff relies too heavily on DCF modeling, but Staff's modeling methodologies and weights are entirely consistent with Commission preference and direction over the last decade.

In contrast, PacifiCorp's filing of PAC/2200 ignores a decade of Commission guidance and direction.

Q. Do Staff and AWEC fail to accurately reflect current market conditions?

A. No. In fact, Staff's modeling is refreshed and current, contrary to the Company's dated and unsupported assumptions addressed herein.

Q. Do Staff and AWEC fail to reflect forward-looking costs of equity?

A. No. That statement by the Company is entirely inconsistent with the Company's overreliance on near term growth rates and extrapolations of immediate market parameters for long-run 20-year projections by referent entities.

Rather the Company avoids plainly stated downward projections of GDP growth in its truncated modeling in an attempt to mask the unreasonable inputs it is relying on. This testimony will repeatedly call out these errors.

Q. Why does Staff continue to rely Value Line beta estimates instead of beta estimates from other sources?

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[155] PAC/220, Bulkley/4.

1 A. Practitioners modeling CoC with a valid set of models and arguments tend to
2 rely on Value Line Betas as a standard on which to showcase their work. In
3 this testimony, Staff will demonstrate use of the Bloomberg and Yahoo
4 Finance Betas as ways that may inappropriately boost or lower the results of
5 simple models like the CAPM.

6 **Q. Do many investors and market managers see and use Bloomberg,**
7 **YAHOO Finance and other Betas from a variety of sources?**

8 A. Yes. But the Commission should decline to give weight to these until
9 future cases. Were the Commission to give any weight to the Bloomberg
10 Beta's for modeling in this GRC, it would reopen arguments for the use of a
11 range of Betas from different sources, each drawing from different markets
12 and data sources, and each calculating the Betas for stocks in a different way
13 based on different formulas and treatments to account for factors like mean
14 reversion.

15 **Q. Does PacifiCorp Summary 7 offer any new argument or**
16 **information?[156]**

17 A. No. PacifiCorp's Summary 7 states merely asserts that:

18 The Commission should consider how current market conditions affect
19 the risk profile for equity investors as well as the results of a broader
20 range of ROE estimation methodologies.

[156] PAC/2200, Bulkley/6.

The Company cites the Hope and Bloomfield decisions, but fails to address whether the Company is *less risky* than the Company peer group, where a just and reasonable ROE would have to be *lower for PacifiCorp* than for PacifiCorp's peer group.

Finally, the Company continues to suggest AWEC and Staff are out of touch with spreads and volatility of bonds in current market conditions. As this testimony has demonstrated, that is not the case as one can readily see from the market news we have provided.

Q. Is PacifiCorp Summary 8 accurate in saying that AWEC and Staff do not consider credit rating risk with respect to Moody's credit rating metrics following the 2017 Tax Act?[157]

A. No. AWEC and Staff are merely pointing out that, given that a balanced capital structure is the norm in Oregon, Commission jurisdictional utilities like Portland General Electric, Avista Corporation, Northwest Natural and Avista already deal with this issue. The Company has not provided compelling evidence in support of why, given its relative size and resources, it would have a harder time. The Company does not explain why PacifiCorp is impaired in some way from dealing with the 2017 Tax Act as effectively as other Oregon utilities.

Q. Has Staff relied exclusively on the results of Multi-Stage DCF modeling as is suggested in PacifiCorp's reply testimony?[158]

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[157] PAC/2200, Bulkley/6.

[158] PAC/2200, Bulkley/7.

A. No. See PAC/2200, Bulkley/8, Figure 1 discussing Staff's Constant Growth DCF and CAPM models where Ms. Bulkley highlights the various models employed by Staff.

Q. Does PacifiCorp attempt to explain why its recommended ROE of 10.2 percent is so much higher than the mean of authorized ROEs for electric utilities decided in 2020?[159]

A. No. PacifiCorp makes no compelling explanation why a very outsized ROE has merit compared to the mean of GRC decision on authorized ROE this year. All that is offered is Ms. Bulkley's judgement, which absent any material support otherwise, is not compelling.

Q. In its update of modeling, PacifiCorp removes Centerpoint Energy, does Staff agree this is reasonable?[160]

A. Yes. With its dividend cuts, Centerpoint is reasonably removed from the Company's peer group. However, Staff notes that a less efficacious screening methodology for the Company leaves the PAC/2200 testimony continuing to argue that PacifiCorp is riskier than peers.

Q. Are low interest rates entirely caused by COVID 19 as implied by PacifiCorp?[161]

A. No. That is an overly simplistic view. Central Banks around the world have worked hard in the last decade to keep interest rates low. This obviously

[159] PAC/2200, Bulkley/9 – 12.
[160] PAC/2200, Bulkley/9 – 12.
[161] PAC/2200, Bulkley/17.

lowers the cost of borrowing, stimulating growth. As one would imagine, with deficit spending, governments prefer lower rates as these lower the cost of their debt obligations.

As a simple mental exercise, one can look at recent lows in UST yields prior to the impact of COVID 19 in the US. So rather than a short-term event, low interest rates have been here for some time. Although Ms. Bulkley asserts that low interest rates are temporary and have "little to do with the longer-term trend in bond yields and equity costs," a variety of federal sources and experts disagree.

In fact, one only needs to look at the trends in interest rates in the last 40 years. The long-term decline in interest rates can be seen in Figure 11, which plots the long-run trend of falling US Treasury rates, along with the comparatively minor decrease in rates in response to COVID-19.

Figure 11

1 **Q. In PAC/2200 Bulkley/19, does Ms. Bulkley confuse reduction in**
2 **volatility in the bond markets with reduction in volatility in the stock**
3 **markets?[162]**
4 A. Yes. That error is repeated several times in the PAC/2200 testimony. For
5 clarity, decision makers will want to review the Wall Street Journal (WSJ)
6 articles on this topic, provided by Staff in this testimony.[163]
7 **Q. Are PAC/2200 Bulkley/28 Figure 9 Spreads for March 27, 2020**
8 **representative of current market spreads over UST?**
9 A. No. Spreads over UST for utilities rated like PacifiCorp have fallen quite a bit
10 since March 27, 2020.[164] Conclusions based on March 27 spreads are no
11 longer predictive of current and near future market conditions.
12 **Q. Does PacifiCorp justify why it fails to use appropriate metrics and**
13 **rates in its modeling such as 30-year growth rates for long-run**
14 **projections.**
15 A. There is sort of a pointing to COVID 19 to deflect from overreliance on near
16 term values in lieu of the appropriate long-run values of appropriate tenure. [165]
17 However, PacifiCorp provides no good justification why inputs should not
18 match the tenure of purpose.

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[162] PAC/2200, Bulkley/19.

[163] See "Investors Bet on Volatility, Making Markets Even Wilder" by Gunjan Banerji – WSJ – Jun. 13, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/123-127.

[164] See "Central Bank Finds No Bond Sellers" by Matt Wirz – WSJ – Jun. 4, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/14-15.

[165] PAC/2200, Bulkley/32.

1 **Q. Does PacifiCorp provide any plausible explanation for why they**
2 **presume money managers and investors do not prefer as peer**
3 **utilities, those with a five-year dividend history?[166]**
4 A. No. Ms. Bulkley asserts that investors and money managers are no longer
5 conservative and cautious,[167] but does not provide evidence in support of this
6 assertion.
7 **Q. Does PacifiCorp explain why a highly regulated utility would not be a**
8 **preferable peer for ROE modeling than companies in different lines of**
9 **business than PacifiCorp, perhaps sand and gravel and**
10 **construction?[168]**
11 A. No. More cyclical companies with businesses like construction are riskier
12 than utilities that are entirely or highly regulated. Naturally in the screening,
13 one's goal is to identify a peer group that is most like the Company studied in
14 terms of risk. The Company has offered no explanation as to why the
15 Commission should consider different lines of business rather than regulated
16 utilities.
17 **Q. PacifiCorp takes issue with screening based on capital structure, is**
18 **this a reasonable objection?[169]**
19 A. No. In fact, this screening method minimizes outboard adjustments and the
20 need for unusual heroic assumptions.

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166 PAC/2200, Bulkley/40.
167 PAC/2200, Bulkley/40.
168 PAC/2200, Bulkley/44.
169 PAC/2200, Bulkley/44.

1 **Q. PacifiCorp seems to have a problem with Staff's use of the Hamada**
2 **Equation. What is Staff's response?[170]**
3 A. This iteration of the Hamada Equation is a standard tool in Oregon for over a
4 decade. Staff believes that that it is an important tool to ensure that
5 authorized capital structures remain just, reasonable and in the public
6 interest.
7 **Q. Does PacifiCorp criticize Staff's method of taking the close of the first**
8 **day of each month of a quarter to generate an average share price?[171]**
9 A. Yes. Staff reiterates that it supports this averaging method because it is
10 resistant to manipulation. The process reduces the risk from human bias
11 since it is essentially formulaic.
12 **Q. Does PacifiCorp seem to assert that Federal Energy Regulatory**
13 **Commission orders and appeals are instructive to the Oregon Public**
14 **Utility Commission?[172]**
15 A. Yes. PacifiCorp suggests that based on several FERC appeals, equal weight
16 should be applied to all ROE models.
17 Although I am not an attorney, it is my understanding that these FERC
18 methodology decisions are not binding on the Oregon Public Utility
19 Commission.

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[171] PAC/2200, Bulkley/49-50.
[172] PAC/2200, Bulkley/58.

1 **ISSUE 7 – STAFF'S UPDATE OF GDP GROWTH RATES**

2 **Q. Has Staff provided updated growth rates?**

3 A. Yes. Staff reviewed each of its sources, to ensure that the most recent
4 growth rates are being reflected in this testimony.

5 Staff has updated its model to include the most recent available
6 Treasury Inflation-Protected Securities (TIPS) data (through Q2 2020) as
7 shown in Exhibit 1909, and the most recent available GDP data (through
8 Q1 2020) as shown in Exhibit 1908. Further, Staff has checked its sources
9 for long-run growth rate forecasts for updates as demonstrated in Exhibit
10 1907.

11 **Q. Does Staff believe that the updated growth rates described above**
12 **reflect lower growth expectations in the post-COVID-19 economy?**

13 A. That is possible. However, the long-run growth rates included in Staff's
14 testimony do specifically account for the fact that "slower population growth
15 and aging demographics" in part driven by lower immigration, and
16 diminished growth in efficiency and investment in plant, equipment,
17 research and development, and training "provide a more challenging
18 backdrop for U.S. growth".[173]

19 The path of new COVID-19 cases is now seen by experts as "key to
20 economic outlook",[174] however at this time no updated long-run growth

[173] See "Quarterly Market Update. Second Quarter 2020", by Fidelity Investments, April 14, 2020. Accessible at: https://institutional.fidelity.com/app/popup/item/RD_13569_30073.html.

[174] Id.

rates are available which reflect COVID-19 scenarios. This is in spite of Staff carrying out a full review of its long-run growth forecast sources, as demonstrated by Exhibit 1807.

Staff expects that the Q2 2020 TIPS data in Exhibit 1909 page 3, which shows a significant decline in results since March 2020, represents only the tip of the iceberg when it comes to reduced growth. This view is supported by the June 2020 report from the Congressional Budget Office (CBO), which indicated that fully recovery will take 10 years.[175]

Considering the above, Staff's acknowledges that its growth rates may be optimistically high, creating an upward bias on ROE estimates but nevertheless are appropriately included in Staff's analysis.

ISSUE 8 – STAFF'S UPDATED SINGLE-STAGE DCF ROE MODEL

Q. What is the Single-Stage DCF model?

A. The Single-Stage DCF (or Gordon Growth model), similar to the Three-Stage DCF model, is based on the principle that a company's value is equal to the net present value (NPV) of all of its future cash flows.

The Single-Stage DCF uses simpler assumptions than other models however, with dividend payments representing the only cash flow, and an assumption that growth will remain constant in perpetuity.[176]

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[175] See "Economy Setback Seen Taking 10 Years to End", by Paul Kiernan and Paul Hannon, Wall Street Journal, June 2, 2020. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/34-36.

[176] See Docket No. UG 347, Staff/1300, Muldoon Watson/31 – 39, for further discussion of the Single-Stage DCF model, and the Commission's historical treatment of its results.

Q. What are the positive aspects, and potential shortfalls of the DCF model?

A. The most positive aspect of the Single-Stage model is its simplicity. An analyst can used this model to calculate a rudimentary cost of equity valuation without needing complex inputs or analysis, beyond selecting a trusted source for the next quarter's expected dividend.

Caution and discretion must be used when sourcing inputs to the model, for example growth rates should be based on well vetted and reliable sources, as opposed to sell-side marketing information used to entice new investors. This is important to bear in mind when considering the results of PacifiCorp's Single-Stage model, as reliance on overly optimistic inputs or use of outboard after-the-fact adjustments can have a large impact on the model output.

As the Single-Stage model is based on simple principles, and serves as a rough finger in the wind estimation of investor required ROE. It cannot incorporate known, measurable and material information about the future usually built into Three-Stage DCF analysis.

Q. Has Staff updated its Single-Stage DCF model?

A. Yes. Staff carried out a full review to the inputs used, ensuring that the most recent available financial data is now reflected in the model's results. As demonstrated in Exhibit Staff/1906, Staff has updated Company share prices, reflected dividends declared for the second quarter of 2020, and updated forecasted dividends for the period through 2025 in its model.

One notable change is that stock markets have been particularly volatile in recent months, resulting in an average fall in share prices of five percent between Staff's opening testimony and rebuttal testimony. This data reflects change occurring over the three months ending June 2020. The majority of Staff's peer group experienced negative pressure on share prices during this period.

Q. What was the result of Staff's updates to the single-stage DCF model?

A. Incorporating lower share prices into Staff's single-stage DCF model, along with minor revisions to expected dividends, resulted in a 9.5 ROE, representing a 0.56 percent increase from Staff's opening testimony, and pointing toward an ROE at the upper end of Staff's Three-Stage DCF Model results.

The results of Staff's single-stage DCF model are illustrated in Exhibit Staff/1907.

ISSUE 9 – STAFF'S UPDATED CAPM ROE MODEL

Q. What is the CAPM?

A. The CAPM is similar to a Risk-Premium model in that it assumes that a stock's return on equity is a function of a risk-free return and a risk premium. Unlike a Risk-Premium Model, CAPM assumes that the risk premium should be augmented by a company's level of risk relative to the market, which is captured by Beta. All told, CAPM takes the form:

$$Required\ Return = r_f + \beta(r_m - r_f)$$

where r_f is the risk-free rate and r_m is the market return. Generally, the risk-free rate is assumed to be the rate of return on 30-year US Treasury bonds.

Q. Are there any reasons the Commission should be wary of CAPM?

A. Yes. Like all models that project required returns, CAPM only relies on a few inputs. In this case, there are three: the risk-free rate, the market return and the choice of Beta. Although it is generally agreed that the rate of return on 30-year US treasury bonds is the proper choice for the risk-free rate, there is much discussion about what should be used for beta and the market return.

There are a variety of sources to find or calculate both Beta and the market return. Because there are so many sources for two inputs into this simple model, an uninformed or malicious investigator could use unrepresentative values to motivate irresponsible required returns. It is therefore of the utmost importance to be thoughtful and consistent in choosing CAPM parameters. In Oregon we have standardized on Value Line (VL) Betas which are broadly relied to give apples-to-apples modeling output comparisons.

Even when the correct inputs are chosen, CAPM is still historically unreliable in precisely and accurately predicting required returns. For this reason, Staff has used CAPM for validation rather than rate setting in past cases. This will be addressed at the end of this section of testimony.

Q. Where does one find information on companies' BETA estimates?

A. Estimates of beta can be found from many sources including Bloomberg, Yahoo Finance, and VL. Traditionally, the Commission has relied on Value

1 Line's beta estimates to conduct analysis in order to maintain consistency in
2 regulation. The perils of switching between Beta estimates, known as "Beta
3 shopping," will be addressed later in this testimony.

4 **Q. Where does one find information on market returns?**

5 A. Market returns can be also be found or calculated from a variety of places.
6 Two common sources for market returns are historical returns on stock
7 market indices and projections for future growth. One must be careful in
8 selecting a market return due to the volatile nature of the stock market.

9 **Q. What issues can arise from an improper market return selection?**

10 A. For any company with a positive Beta, a higher market return translates
11 directly into a higher required return according to the CAPM formula. The
12 average VL Beta for companies that were in either the Company's or the
13 Staff's peer screen was .76, and it is common to see market return estimates
14 vary by as much as 400 basis points. This means that by only substituting in
15 a different estimate for market returns, a required return estimate can vary by
16 approximately 300 basis points for a typical regulated utility.

17 **Q. How does PacifiCorp estimate the market return?**

18 A. In Ms. Bulkley's testimony, she estimates the market return using estimated
19 dividend yields and long-term growth estimates from the S&P 500 Earnings
20 and Estimate Report from May 29, 2020.[177]

21 **Q. Does Staff believe this was an appropriate way to model the market**
22 **return?**

[177] See Exhibit PAC/2205, Bulkley/7.

A. No, we do not. The report was published in the middle of the stock market's dramatic recovery after the initial crash due to the COVID-19 outbreak. The long-term growth estimates for companies in the May 29 report are therefore factoring in a rebound toward a long-term trend without needing to account for the large drop that warranted the rebound. Therefore, the long-term trends will lead to an estimated market return that is unrepresentatively high.

Q. How does Staff recommend that market returns be calculated instead?

A. Staff recommends that market returns instead be calculated based off the historic growth. By doing so, a model maker can find a much more representative market return that is not biased by a shock in one period.

Q. What were PacifiCorp's fundamental disagreements about Staff's treatment of CAPM?

A. PacifiCorp has four main concerns about the CAPM estimation:

1. Staff's source of Beta estimates,
2. The composition of Staff's proxy group,
3. The lack of any ECAPM analysis, and
4. PacifiCorp objects to Staff setting the rate based only on the multi-stage DCF model rather than choosing to give weight to multiple models, including CAPM.[178]

Q. What were Ms. Bulkley's criticisms of Staff's previous CAPM analysis?

[178] PAC/2200, Bulkley/60.

1 A. In her testimony, Ms. Bulkley noted that Staff has historically only relied on
2 Beta estimates from Value Line rather than also considering also considering
3 beta estimates from other sources. She proposes that Staff also consider
4 Beta estimates from Bloomberg that update more frequently, and would thus
5 provide a more up-to-date beta estimation. Ms. Bulkley also advocates that
6 Staff update its Value Line Betas.[179]

7 **Q. What has Staff done to address Ms. Bulkley's concerns about Staff's**
8 **choice of Beta estimates for its CAPM models?**

9 A. Staff took Ms. Bulkley's criticism to heart and updated its CAPM models with
10 the most recent VL beta estimates for both its proxy group and the proxy
11 group defined in Ms. Bulkley's reply testimony. In addition to the VL betas,
12 Staff also uses Beta estimates from Yahoo Finance as a robustness check.

13 **Q. Has Staff made any additional updates to its CAPM modelling**
14 **technique?**

15 A. Yes. Staff has made two updates in order to be more consistent with Ms.
16 Bulkley's modelling techniques. First, Staff has adjusted our risk-free rate to
17 the most recent yield on 30-year US Treasury bonds of 1.326 percent, as
18 reported in the Wall Street Journal on July 9, 2020.

19 Second, instead of using Morningstar's long-run market risk premium of
20 6 percent, Staff instead calculated the market risk premium using the 30-year
21 average market return on the S&P 500. From January 1, 1989 to January 1
22 2019, the S&P grew an average of 9.51 percent annually according to the

[179] PAC/2200, Bulkley/63.

CFA Institute. It should be noted that the historic S&P 500 growth rate used by Staff is a full 377 basis points less than the one used in Ms. Bulkley's testimony, indicating that Ms. Bulkley's CAPM estimation is being skewed by a long-term growth rate that is historically unprecedented. By using historical growth rates rather than projections, Staff avoids any undue bias from a temporary rebound in the economy after the COVID-19 pandemic that Ms. Bulkley's testimony suffers from. Netting out the risk-free rate used of 1.326 percent yields a risk premium of 8.18 percent.

Q. How do the updated risk-free rate, risk premium, and VL's updated Beta estimates change the CAPM analysis from Staff's Opening Testimony?

A. Using the VL beta estimates, we find a mean ROE of 7.5 percent using the Company's screen and 7.6 percent using Staff's screen.

In her reply testimony, Ms. Bulkley advocates taking the mean after removing all ROE estimates below 7.0 percent because they "are too low to be meaningful representations of the cost of equity."[180] Staff goes a step further and removes all estimates below 8.0 percent. After removing ROE estimates below 8.0 percent in Staff's screen, we find that the minimum return is approximate 8.7 percent and the maximum return is 9.9 percent with a mean value of 9.3 percent.

Q. What recommendations do you have for the maximum authorized ROE?

[180] PAC/200, Bulkley/74.

A. Our CAPM using VL betas supports Mr. Gorman's recommendation of an authorized ROE of 9.20 percent. Staff's maximum supportable ROE at the top of its modeling range of reasonable ROEs is 9.42 percent.

Q. How do the updated risk-free rate, risk premium, and Yahoo Finance's Beta estimates change the CAPM analysis from Staff's opening testimony?

A. As was the case in Ms. Bulkley's testimony, the beta estimates from other sources led to very different required returns from our CAPM analysis. Unlike Ms. Bulkley, we decided to use beta estimates from Yahoo Finance. Like Bloomberg, Yahoo Finance is another widely used source for financial information that is updated more frequently than Value Line. As of July 7, Yahoo Finance's beta estimates for both Staff's and Ms. Bulkley's peer screens fell since the onset of the COVID-19 pandemic and are much lower than Value Line's and Bloomberg's beta estimates.

Using Yahoo Finance's beta estimates, we found that the average authorized return on equity for companies within Company's peer screen and Staff's peer screen are 4.7 percent and 4.1 percent, respectively. This points to the danger in uninformed beta shopping when performing comparisons between companies.

Q. What is Beta shopping?

A. Beta shopping warrants its own separate discussion outside of this testimony. However, without getting into excessive detail, it is the act of looking to many sources to find a beta. For the purpose of this testimony, beta shopping could

be used to find the most optimal beta to substantiate any financing decisions. As was demonstrated above, by switching between beta estimates from VL, Bloomberg and Yahoo Finance, one could justify authorized returns well below 5 percent. For this reason, Staff chooses to rely solely on beta estimates from VL when conducting CAPM analysis in order to maintain fair and consistent analysis between rate cases.

Q. What objections does Ms. Bulkley have about Staff's choice of a proxy group?

A. Ms. Bulkley believes that Staff's choice of a peer screen is overly restrictive. Staff will limit our discussion of the peer screen here because it was previously addressed in Staff's reply testimony.

Q. In her testimony on behalf of PacifiCorp, MS. Bulkley objects that Staff did not create an ECAPM when recommending an authorized rate of return. What is an ECAPM?

A. ECAPM stands for "Empirical CAPM." It was created in response to the standard CAPM underestimating returns for companies with betas lower than 1 and overestimating returns for companies with betas higher than 1. According to ECAPM, the remedy for this problem is to take weight away from beta and add weight to the market risk premium. In her testimony, Ms. Bulkley estimates the following ECAPM equation: [181]

$$Required\ Return = r_f + .75\beta\left(r_m - r_f\right) + .25(r_m - r_f)$$

[181] PAC/400, Bulkley/58.

1 Doing this brings all returns nearer to the market rate.

2 **Q. Why Doesn't Staff perform an ECAPM analysis as described by Ms.**
3 **Bulkley?**

4 A. As pointed out in Staff's opening testimony, ECAPM is primarily used to
5 reweight CAPM estimates to help investors get a good guess of a required
6 return. The Commission has traditionally never relied on an ECAPM analysis
7 due to its atheoretical nature and its manipulative use by investors advocating
8 for higher returns.

9 **Q. What is atheoretical about ECAPM?**

10 A. As previously stated, ECAPM takes weight away from Beta and adds weight
11 to the raw market risk premium. However, there is no theory behind the
12 weight given to each separate component. For example, in Ms. Bulkley's
13 testimony, she puts a weight of .75 on beta and .25 on the market risk
14 premium. She could have very well changed the beta weight to .9, .4, or zero
15 in an ECAPM analysis. Put another way, ECAPM allows one to put as much
16 weight on beta as they see fit.

17 **Q. How can this be used manipulatively?**

18 A. Regulated utilities traditionally have very low beta scores that tend to be less
19 than 1.0 as utilities are historically seen as safe investments. That means
20 that anyone using a traditional CAPM will expect to see a low required return
21 for any utility company. Therefore, by taking weight away from beta and
22 putting it towards the market risk premium as one does in ECAPM, an analyst

could artificially inflate the required return needed for investment. For this reason, Staff has traditionally disregarded all ECAPM analysis.

Q. PacifiCorp also objects to Staff not putting any weight on CAPM when setting its authorized weight. How does Staff respond to this?

A. As has been stated above, Staff has traditionally relied on a Three-Stage DCF model to set its recommended rate of return and merely relies on CAPM and single-stage DCF models for validity checks. In our rebuttal testimony, Staff have discussed why we believe the Three-Stage DCF model to be the most appropriate model to set rates. Staff also notes that despite its popularity, CAPM is notoriously unreliable and therefore not a good choice for primary rate authorization decisions.

Q. What do you mean by CAPM being unreliable?

A. CAPM gained popularity in the middle of the twentieth century for its easy equation and clean interpretation. As discussed in the ECAPM analysis, CAPM has been found to be notoriously inaccurate when nailing down the exact required Rate of Return. This is such a widely-accepted phenomenon that academics have accepted it as a financial truth.[182] In fact, Ms. Bulkley acknowledges the shortcomings of CAPM when advocating for ECAPM.[183] Despite this, Ms. Bulkley still gives weight to CAPM when making her recommendation for PacifiCorp's authorized return.

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[182] See Fama, E. F., & French, K. R. (2004). The capital asset pricing model: Theory and evidence. *Journal of economic perspectives*, *18*(3), 25-46. for a thorough review of the literature of CAPM. Reproduced in Exhibit Staff/1911, Muldoon-Enright-Dlouhy/404-454.

[183] See PAC/400, Bulkley/58.

CAPM is widely used and easily implemented enough that Staff takes no issue in performing a CAPM analysis as a robustness check for our main rate-setting model. However, for the reasons stated above Staff firmly believes that CAPM should not be used as a primary tool to authorize rates.

ISSUE 10 – COST OF LONG-TERM DEBT (LT DEBT)

Q. What was the Company's position regarding the Staff's adjustments for the cost of LT Debt?

A. The Company agreed with Staff's calculation of its LT Debt costs, including an adjustment replacing forecasted debt issuances in 2020 and 2021 with the amount, interest rates, terms and costs of its April 2020 debt issuance.

The Company noted that Staff's standard adjustment, removing maturing LT Debt from the calculation, had the effect of increasing the Company's cost of LT Debt. Absent this adjustment, PacifiCorp's calculation of the cost of LT Debt is 4.774 percent, and the Company continues to advocate for this value.

Q. What is Staff's response?

A. Staff maintains its original position on this matter, for a recommended cost of LT Debt of 4.824. Staff's adjustment for currently maturing debt is consistent with the test year scenario, ensuring that the rates coming into effect adequately reflect costs incurred by the Company in the test year.

Staff has a track record of ensuring fair and reasonable rates for both utilities and utility customers in Oregon, and a centerpiece of this is the use

of standard models to measure the Cost of LT Debt and ROE, without adding adjustments or grey areas. Determining a utility's CoC in a clear and transparent manner, as has been Staff's practice to date, is in the interest of the Commission, jurisdictional utilities, and customers.

CONCLUSION

Q. Please summarize your recommendations regarding capital structure.

A. Staff finds that Mr. Gorman testifying for AWEC makes compelling arguments and Staff joins AWEC in this testimony in recommending a capital structure of 50.64 percent equity and 49.35 percent LT Debt, moving away from Staff's earlier recommended 52 percent equity layer in Opening Testimony.

Q. Please summarize your recommendations regarding ROE.

A. After updating its ROE modeling entirely, Staff still recommends a point ROE of 9.0 percent but now within a slightly upshifted range of reasonable ROEs of 8.57 percent to 9.42 percent. In contrast, Mr. Gorman writing for AWEC recommended a 9.20 percent ROE for PacifiCorp. And Staff's uppermost range of modeling supports a 9.42 percent ROE

Q. What Cost of LT Debt does Staff recommend?

A. Staff recommends the Commission adopt a 4.824 percent Cost of LT Debt. This is higher than the 4.774 percent Cost of LT Debt that the Company recommends. Staff's methods are consistent and reasonable for all Commission jurisdictional energy utilities, even when that results in higher Staff recommendations.

Q. What aggregate ROR does Staff recommend be derived from the components of CoC summarized above?

A. Staff recommends the Commission authorize a 6.939 percent ROR should the Commission adopt a 9.0 percent ROE for PacifiCorp. Conversely, should

1 the Commission find the top range of Staff's ROEs has greater merit, that
2 9.42 percent ROE would, all else constant, translate to a 7.152 percent ROR.
3 **Q. Does this conclude your testimony?**
4 A. Yes.

CASE: UE 374
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1901

Witness Qualifications Statement

July 24, 2020

WITNESS QUALIFICATION STATEMENT

NAME: Curtis Dlouhy

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance, and Audit Division

ADDRESS: 201 High St. SE, Ste. 100
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EDUCATION: PhD, Economics
University of Oregon,
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Master of Science, Economics
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University, Lincoln, NE

EXPERIENCE: I have been employed by the Oregon Public Utility Commission (OPUC) since June 2020 in the Energy Rates, Finance, and Audit Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues.

Prior to working for the Commission I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization and Antitrust Economics. My PhD dissertation covered various topics in fossil fuel markets ranging from coal mine closure, electricity choices under carbon taxes and coal transport via railroad.

CASE: UE 374
WITNESSES: MATT MULDOON-
MOYA ENRIGHT-
CURTIS DLOUHY

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1902
Cost of LT Debt

Exhibits in Support of Rebuttal Testimony

NON-CONFIDENTIAL
July 24, 2020

Staff Exhibit 1902 is

Confidential

And filed in electronic format

Subject to Protective Order 20-040

CASE: UE 374
WITNESSES: MATT MULDOON-
MOYA ENRIGHT-
CURTIS DLOUHY

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1903
ROE Peer Screening

Exhibits in Support of Rebuttal Testimony

July 24, 2020

Staff Exhibit 1903 is

filed in electronic format

5.05% Annual Growth Rate - Stage 3

EPS Growth to Determine a Sale Terminal Value

EPS Growth

E.O.Y. Cash Flows

Staff Model Y

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
						Terminal Value as % of NPV_{DIV}			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	Screen #	Abbreviated Utility	UE 374 PAC	UE 374 Staff	IRR		NPV @ IRR	Recent Price*	Initial Stage					Transition Stage				
1	1	Allete	Yes	No	9.8%	33.9%	0.00	(56.97)	2.47	2.58	2.68	2.79	2.90	3.01	3.27	3.51	3.72	3.91
				e					3.05	3.50	3.73	3.98	4.25	4.52	4.90	5.26	5.59	5.87
2	2	Alliant	Yes	Yes	8.9%	38.7%	0.00	(48.58)	1.52	1.64	1.75	1.87	2.00	2.13	2.35	2.55	2.73	2.86
				e					2.45	2.55	2.69	2.84	3.00	3.16	3.45	3.73	3.97	4.17
3	3	Ameren	Yes	Yes	8.4%	48.0%	0.00	(72.61)	2.01	2.11	2.22	2.33	2.45	2.57	2.80	3.01	3.20	3.36
				e					3.45	3.65	3.91	4.20	4.50	4.80	5.28	5.71	6.09	6.40
4	4	AEP	Yes	No	9.0%	37.7%	0.00	(82.67)	2.84	3.00	3.17	3.36	3.55	3.74	4.10	4.43	4.72	4.96
				e					4.25	4.55	4.77	5.01	5.25	5.49	6.00	6.46	6.88	7.22
5	6	Avista	Yes	No	9.3%	33.8%	0.00	(39.53)	1.62	1.68	1.75	1.82	1.90	1.98	2.14	2.29	2.43	2.56
				e					1.95	2.20	2.30	2.40	2.50	2.60	2.76	2.92	3.07	3.23
7	9	CMS	Yes	No	8.8%	44.6%	0.00	(58.03)	1.63	1.74	1.87	2.00	2.15	2.30	2.54	2.76	2.95	3.10
				e					2.60	2.75	2.98	3.23	3.50	3.77	4.18	4.54	4.86	5.10
8	10	Consol Ed	No	Yes	9.0%	34.2%	0.00	(75.26)	3.06	3.16	3.27	3.38	3.50	3.62	3.90	4.16	4.41	4.63
				e					4.25	4.55	4.70	4.85	5.00	5.15	5.53	5.89	6.23	6.54
9	11	Dominion	Yes	No	10.4%	38.0%	0.00	(81.11)	3.76	3.86	3.95	4.05	4.15	4.25	4.58	4.90	5.20	5.46
				e					3.30	4.30	4.67	5.07	5.50	5.93	6.72	7.43	8.01	8.41
10	12	DTE	Yes	No	9.6%	33.2%	0.00	(106.27)	4.12	4.42	4.67	4.93	5.20	5.47	6.03	6.55	6.99	7.34
				e					6.50	6.90	7.32	7.77	8.25	8.73	9.53	10.27	10.92	11.47
11	13	Duke	Yes	No	9.2%	33.4%	0.00	(83.39)	3.82	3.89	3.96	4.03	4.10	4.17	4.45	4.72	4.99	5.24
				e					5.10	5.30	5.52	5.76	6.00	6.24	6.80	7.33	7.79	8.18
12	16	Entergy	Yes	No	9.4%	36.5%	0.00	(97.05)	3.74	3.86	4.08	4.31	4.55	4.79	5.19	5.56	5.90	6.20
				e					5.05	5.80	6.18	6.57	7.00	7.43	7.99	8.52	9.03	9.48
13	17	Evergy	Yes	No	For Future Use													
				e														
14	18	Eversource	No	Yes	8.5%	46.7%	0.00	(82.56)	2.27	2.40	2.54	2.69	2.85	3.01	3.30	3.57	3.80	3.99
				e					3.65	3.85	4.13	4.43	4.75	5.07	5.58	6.05	6.45	6.78
15	20	First Energy	Yes	No	10.1%	41.2%	0.00	(40.77)	1.57	1.61	1.70	1.80	1.90	2.00	2.17	2.33	2.48	2.60
				e					1.85	2.75	2.91	3.07	3.25	3.43	3.84	4.21	4.51	4.74
16	24	IDACORP	Yes	No	8.4%	38.8%	0.00	(90.79)	2.73	2.93	3.12	3.33	3.55	3.77	4.16	4.51	4.82	5.06
				e					4.55	4.75	4.91	5.08	5.25	5.42	5.82	6.20	6.56	6.89
17	26	NextEra	Yes	No	9.3%	50.2%	0.00	(242.28)	5.60	6.16	6.78	7.45	8.20	8.95	10.14	11.21	12.08	12.69
				e					7.50	9.80	10.63	11.53	12.50	13.47	15.22	16.79	18.07	18.98
18	27	NorthWestern	Yes	No	9.2%	32.2%	0.00	(57.44)	2.40	2.50	2.60	2.70	2.80	2.90	3.14	3.37	3.58	3.76
				e					3.45	3.55	3.69	3.84	4.00	4.16	4.45	4.74	5.01	5.26
19	28	OGE	Yes	Yes	10.5%	22.9%	0.00	(31.07)	1.60	1.68	1.77	1.86	1.95	2.04	2.25	2.43	2.59	2.72
				e					2.15	2.25	2.33	2.41	2.50	2.59	2.78	2.96	3.13	3.29
20	29	Otter Tail	Yes	No	8.8%	37.4%	0.00	(42.03)	1.48	1.56	1.64	1.72	1.80	1.88	2.05	2.21	2.35	2.47
				e					2.05	2.20	2.30	2.40	2.50	2.60	2.81	3.00	3.18	3.34
21	31	PGE	Yes	Yes	9.1%	34.7%	0.00	(45.24)	1.62	1.72	1.82	1.93	2.05	2.17	2.39	2.59	2.76	2.90
				e					2.50	2.65	2.76	2.88	3.00	3.12	3.38	3.62	3.85	4.04
22	32	Pinnacle	Yes	Yes	9.8%	30.6%	0.00	(76.06)	3.22	3.41	3.60	3.79	4.00	4.21	4.62	4.99	5.32	5.59
				e					4.75	5.15	5.42	5.70	6.00	6.30	6.84	7.35	7.81	8.20
23	33	PNM	Yes	No	9.1%	46.5%	0.00	(39.92)	1.24	1.30	1.36	1.43	1.50	1.57	1.72	1.86	1.98	2.08
				e					1.80	2.25	2.41	2.57	2.75	2.93	3.26	3.56	3.81	4.00
24	34	PPL	Yes	No	10.7%	21.2%	0.00	(26.40)	1.66	1.67	1.71	1.76	1.80	1.84	1.96	2.08	2.20	2.31
				e					2.40	2.45	2.55	2.65	2.75	2.85	3.06	3.25	3.44	3.61
25	38	Southern	Yes	No	9.5%	31.2%	0.00	(55.22)	2.54	2.62	2.70	2.78	2.86	2.94	3.16	3.37	3.57	3.75
				e					3.10	3.25	3.41	3.58	3.75	3.92	4.22	4.50	4.76	5.00
26	40	WEC	No	Yes	8.5%	44.9%	0.00	(89.98)	2.53	2.70	2.86	3.02	3.20	3.38	3.71	4.02	4.29	4.51
				e					3.75	3.95	4.20	4.47	4.75	5.03	5.51	5.96	6.35	6.67
27	42	Xcel	Yes	No	8.3%	46.9%	0.00	(63.70)	1.72	1.82	1.92	2.03	2.15	2.27	2.49	2.69	2.87	3.02
				e					2.75	2.90	3.09	3.29	3.50	3.71	4.07	4.40	4.69	4.93

	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	
	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value	2049 Div	2049 Sale	2050	Screen #
	Final Stage																							
1	4.11	4.31	4.53	4.76	5.00	5.25	5.52	5.80	6.09	6.40	6.72	7.06	7.42	7.79	8.19	8.60	9.03	9.49	9.97	318.89	10.47	308.42		1
	6.16	6.48	6.80	7.15	7.51	7.89	8.28	8.70	9.14	9.60	10.09	10.60	11.13	11.70	12.29	12.91	13.56	14.24	14.96		15.72		16.51	
2	3.01	3.16	3.32	3.49	3.66	3.85	4.04	4.25	4.46	4.69	4.92	5.17	5.43	5.71	6.00	6.30	6.62	6.95	7.30	240.39	7.67	232.72		2
	4.38	4.60	4.83	5.08	5.34	5.60	5.89	6.19	6.50	6.83	7.17	7.53	7.91	8.31	8.73	9.17	9.64	10.12	10.63		11.17		11.74	
3	3.53	3.70	3.89	4.09	4.29	4.51	4.74	4.98	5.23	5.49	5.77	6.06	6.37	6.69	7.03	7.38	7.76	8.15	8.56	387.75	8.99	378.76		3
	6.72	7.06	7.41	7.79	8.18	8.59	9.03	9.48	9.96	10.47	11.00	11.55	12.13	12.75	13.39	14.07	14.78	15.52	16.31		17.13		18.00	
4	5.21	5.47	5.74	6.03	6.34	6.66	7.00	7.35	7.72	8.11	8.52	8.95	9.40	9.88	10.38	10.90	11.45	12.03	12.64	408.62	13.27	395.35		4
	7.59	7.97	8.37	8.80	9.24	9.71	10.20	10.71	11.25	11.82	12.42	13.05	13.70	14.40	15.12	15.89	16.69	17.53	18.42		19.35		20.33	
5	2.69	2.82	2.97	3.11	3.27	3.44	3.61	3.79	3.98	4.19	4.40	4.62	4.85	5.10	5.36	5.63	5.91	6.21	6.52	190.93	6.85	184.08		6
	3.39	3.56	3.74	3.93	4.13	4.34	4.56	4.79	5.03	5.28	5.55	5.83	6.12	6.43	6.76	7.10	7.46	7.83	8.23		8.64		9.08	
7	3.25	3.42	3.59	3.77	3.96	4.16	4.37	4.59	4.82	5.07	5.32	5.59	5.88	6.17	6.48	6.81	7.16	7.52	7.90	328.82	8.30	320.52		9
	5.36	5.63	5.92	6.22	6.53	6.86	7.21	7.57	7.95	8.35	8.77	9.22	9.68	10.17	10.69	11.23	11.79	12.39	13.01		13.67		14.36	
8	4.87	5.11	5.37	5.64	5.93	6.23	6.54	6.87	7.22	7.58	7.97	8.37	8.79	9.23	9.70	10.19	10.71	11.25	11.81	338.40	12.41	325.99		10
	6.87	7.22	7.58	7.97	8.37	8.79	9.24	9.70	10.19	10.71	11.25	11.82	12.41	13.04	13.70	14.39	15.12	15.88	16.68		17.52		18.41	
9	5.74	6.03	6.33	6.65	6.98	7.34	7.71	8.10	8.51	8.94	9.39	9.86	10.36	10.88	11.43	12.01	12.62	13.25	13.92	596.28	14.63	581.66		11
	8.83	9.28	9.75	10.24	10.76	11.30	11.87	12.47	13.10	13.76	14.46	15.19	15.96	16.76	17.61	18.50	19.43	20.41	21.45		22.53		23.67	
10	7.71	8.10	8.51	8.94	9.39	9.87	10.36	10.89	11.44	12.01	12.62	13.26	13.93	14.63	15.37	16.15	16.96	17.82	18.72	547.53	19.66	527.87		12
	12.05	12.66	13.30	13.97	14.68	15.42	16.20	17.02	17.88	18.78	19.73	20.72	21.77	22.87	24.02	25.24	26.51	27.85	29.26		30.73		32.29	
11	5.50	5.78	6.07	6.38	6.70	7.04	7.40	7.77	8.16	8.57	9.01	9.46	9.94	10.44	10.97	11.52	12.11	12.72	13.36	390.58	14.03	376.55		13
	8.60	9.03	9.49	9.97	10.47	11.00	11.55	12.14	12.75	13.39	14.07	14.78	15.53	16.31	17.13	18.00	18.91	19.86	20.87		21.92		23.03	
12	6.51	6.84	7.18	7.55	7.93	8.33	8.75	9.19	9.66	10.14	10.66	11.19	11.76	12.35	12.98	13.63	14.32	15.04	15.80	529.36	16.60	512.76		16
	9.96	10.46	10.99	11.55	12.13	12.74	13.39	14.06	14.77	15.52	16.30	17.13	17.99	18.90	19.85	20.86	21.91	23.02	24.18		25.40		26.68	
13																								17
14	4.19	4.41	4.63	4.86	5.11	5.37	5.64	5.92	6.22	6.54	6.87	7.21	7.58	7.96	8.36	8.78	9.23	9.69	10.18	442.23	10.70	431.53		18
	7.12	7.48	7.86	8.26	8.67	9.11	9.57	10.06	10.56	11.10	11.66	12.25	12.86	13.51	14.20	14.91	15.67	16.46	17.29		18.16		19.08	
15	2.73	2.87	3.02	3.17	3.33	3.50	3.67	3.86	4.05	4.26	4.47	4.70	4.94	5.18	5.45	5.72	6.01	6.31	6.63	300.95	6.97	293.98		20
	4.98	5.23	5.50	5.77	6.06	6.37	6.69	7.03	7.39	7.76	8.15	8.56	8.99	9.45	9.93	10.43	10.95	11.51	12.09		12.70		13.34	
16	5.32	5.59	5.87	6.17	6.48	6.80	7.15	7.51	7.89	8.29	8.71	9.15	9.61	10.09	10.60	11.14	11.70	12.29	12.91	400.29	13.56	386.72		24
	7.23	7.60	7.98	8.39	8.81	9.26	9.72	10.21	10.73	11.27	11.84	12.44	13.07	13.73	14.42	15.15	15.91	16.72	17.56		18.45		19.38	
17	13.33	14.00	14.71	15.45	16.23	17.05	17.91	18.82	19.77	20.77	21.82	22.92	24.07	25.29	26.57	27.91	29.32	30.80	32.35	1,759.31	33.99	1,725.32		26
	19.94	20.95	22.00	23.11	24.28	25.51	26.80	28.15	29.57	31.06	32.63	34.28	36.01	37.83	39.74	41.75	43.86	46.07	48.40		50.84		53.41	
18	3.95	4.15	4.35	4.57	4.81	5.05	5.30	5.57	5.85	6.15	6.46	6.78	7.13	7.49	7.86	8.26	8.68	9.12	9.58	256.55	10.06	246.49		27
	5.53	5.81	6.10	6.41	6.73	7.07	7.43	7.80	8.20	8.61	9.05	9.50	9.98	10.49	11.02	11.57	12.16	12.77	13.41		14.09		14.80	
19	2.86	3.01	3.16	3.32	3.48	3.66	3.85	4.04	4.24	4.46	4.68	4.92	5.17	5.43	5.70	5.99	6.29	6.61	6.95	141.17	7.30	133.88		28
	3.46	3.63	3.82	4.01	4.21	4.42	4.65	4.88	5.13	5.39	5.66	5.95	6.25	6.56	6.89	7.24	7.61	7.99	8.40		8.82		9.27	
20	2.59	2.73	2.86	3.01	3.16	3.32	3.49	3.66	3.85	4.04	4.25	4.46	4.69	4.92	5.17	5.43	5.71	6.00	6.30	199.28	6.62	192.66		29
	3.51	3.69	3.87	4.07	4.27	4.49	4.71	4.95	5.20	5.47	5.74	6.03	6.34	6.66	6.99	7.35	7.72	8.11	8.52		8.95		9.40	
21	3.05	3.20	3.36	3.53	3.71	3.90	4.09	4.30	4.52	4.74	4.98	5.24	5.50	5.78	6.07	6.38	6.70	7.04	7.39	213.51	7.77	205.75		31
	4.24	4.46	4.68	4.92	5.17	5.43	5.70	5.99	6.30	6.61	6.95	7.30	7.67	8.05	8.46	8.89	9.34	9.81	10.30		10.82		11.37	
22	5.87	6.17	6.48	6.81	7.15	7.51	7.89	8.29	8.71	9.15	9.61	10.09	10.60	11.14	11.70	12.29	12.91	13.57	14.25	384.63	14.97	369.66		32
	8.62	9.05	9.51	9.99	10.50	11.03	11.58	12.17	12.78	13.43	14.11	14.82	15.57	16.35	17.18	18.05	18.96	19.91	20.92		21.98		23.09	
23	2.19	2.30	2.42	2.54	2.67	2.80	2.94	3.09	3.25	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.06	5.31	255.32	5.58	249.74		33
	4.20	4.42	4.64	4.87	5.12	5.38	5.65	5.94	6.24	6.55	6.88	7.23	7.59	7.98	8.38	8.80	9.25	9.71	10.20		10.72		11.26	
24	2.43	2.55	2.68	2.81	2.95	3.10	3.26	3.42	3.60	3.78	3.97	4.17	4.38	4.60	4.83	5.08	5.33	5.60	5.89	118.08	6.18	111.89		34
	3.80	3.99	4.19	4.40	4.62	4.86	5.10	5.36	5.63	5.92	6.22	6.53	6.86	7.20	7.57	7.95	8.35	8.77	9.22		9.68		10.17	
25	3.94	4.14	4.35	4.57	4.80	5.04	5.30	5.56	5.85	6.14	6.45	6.78	7.12	7.48	7.86	8.25	8.67	9.11	9.57	260.75	10.05	250.70		38
	5.25	5.52	5.80	6.09	6.40	6.72	7.06	7.42	7.79	8.19	8.60	9.03	9.49	9.97	10.47	11.00	11.56	12.14	12.75		13.40		14.07	
26	4.73	4.97	5.22	5.49	5.77	6.06	6.36	6.68	7.02	7.38	7.75	8.14	8.55	8.98	9.44	9.91	10.41	10.94	11.49	462.12	12.07	450.05		40
	7.00	7.36	7.73	8.12	8.53	8.96	9.41	9.89	10.38	10.91	11.46	12.04	12.65	13.29	13.96	14.66	15.40	16.18	17.00		17.86		18.76	
27	3.17	3.33	3.50	3.67	3.86	4.05	4.26	4.47	4.70	4.94	5.19	5.45	5.72	6.01	6.32	6.64	6.97	7.32	7.69	329.50	8.08	321.42		42
	5.18	5.44	5.72	6.01	6.31	6.63	6.96	7.31	7.68	8.07	8.48	8.91	9.36	9.83	10.33	10.85	11.39	11.97	12.57		13.21		13.88	

No. of Peers: 23 8

	Mean	
9.34%	36.89%	0.00%
9.06%	37.59%	0.00%

Company Screen

Staff Screen

B.O.Y. Cash Flows Staff Model Y EPS Growth

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	
						Terminal Value as % of NPV_{DIV}			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value	2049 Div	2049 Sale	2050	#	
	#	Abbreviated Utility	UE 374 PAC	UE 374 Staff	IRR		NPV @ IRR	Recent Price*	Initial Stage					Transition Stage					Final Stage																							
1	1	Allete	Yes	No	10.0%	32.1%	0.00	(56.97)	2.58	2.68	2.79	2.90	3.01	3.27	3.51	3.72	3.91	4.11	4.31	4.53	4.76	5.00	5.25	5.52	5.80	6.09	6.40	6.72	7.06	7.42	7.79	8.19	8.60	9.03	9.49	9.97	10.47	319.42	11.00	308.42		1	1
				e					3.05	3.50	3.73	3.98	4.25	4.52	4.90	5.26	5.59	5.87	6.16	6.48	6.80	7.15	7.51	7.89	8.28	8.70	9.14	9.60	10.09	10.60	11.13	11.70	12.29	12.91	13.56	14.24	14.96		15.72		16.51		
2	2	Alliant	Yes	Yes	9.1%	36.6%	0.00	(48.58)	1.64	1.75	1.87	2.00	2.13	2.35	2.55	2.73	2.86	3.01	3.16	3.32	3.49	3.66	3.85	4.04	4.25	4.46	4.69	4.92	5.17	5.43	5.71	6.00	6.30	6.62	6.95	7.30	7.67	240.78	8.06	232.72		2	2
				e					2.45	2.55	2.69	2.84	3.00	3.16	3.45	3.73	3.97	4.17	4.38	4.60	4.83	5.08	5.34	5.60	5.89	6.19	6.50	6.83	7.17	7.53	7.91	8.31	8.73	9.17	9.64	10.12	10.63		11.17		11.74		
3	3	Ameren	Yes	Yes	8.5%	46.1%	0.00	(72.61)	2.11	2.22	2.33	2.45	2.57	2.80	3.01	3.20	3.36	3.53	3.70	3.89	4.09	4.29	4.51	4.74	4.98	5.23	5.49	5.77	6.06	6.37	6.69	7.03	7.38	7.76	8.15	8.56	8.99	388.21	9.45	378.76		3	3
				e					3.45	3.65	3.91	4.20	4.50	4.80	5.28	5.71	6.09	6.40	6.72	7.06	7.41	7.79	8.18	8.59	9.03	9.48	9.96	10.47	11.00	11.55	12.13	12.75	13.39	14.07	14.78	15.52	16.31		17.13		18.00		
4	4	AEP	Yes	No	9.2%	35.7%	0.00	(82.67)	3.00	3.17	3.36	3.55	3.74	4.10	4.43	4.72	4.96	5.21	5.47	5.74	6.03	6.34	6.66	7.00	7.35	7.72	8.11	8.52	8.95	9.40	9.88	10.38	10.90	11.45	12.03	12.64	13.27	409.29	13.94	395.35		4	4
				e					4.25	4.55	4.77	5.01	5.25	5.49	6.00	6.46	6.88	7.22	7.59	7.97	8.37	8.80	9.24	9.71	10.20	10.71	11.25	11.82	12.42	13.05	13.70	14.40	15.12	15.89	16.69	17.53	18.42		19.35		20.33		
5	6	Avista	Yes	No	9.5%	32.0%	0.00	(39.53)	1.68	1.75	1.82	1.90	1.98	2.14	2.29	2.43	2.56	2.69	2.82	2.97	3.11	3.27	3.44	3.61	3.79	3.98	4.19	4.40	4.62	4.85	5.10	5.36	5.63	5.91	6.21	6.52	6.85	191.28	7.20	184.08		6	5
				e					1.95	2.20	2.30	2.40	2.50	2.60	2.76	2.92	3.07	3.23	3.39	3.56	3.74	3.93	4.13	4.34	4.56	4.79	5.03	5.28	5.55	5.83	6.12	6.43	6.76	7.10	7.46	7.83	8.23		8.64		9.08		
7	9	CMS	Yes	No	9.0%	42.5%	0.00	(58.03)	1.74	1.87	2.00	2.15	2.30	2.54	2.76	2.95	3.10	3.25	3.42	3.59	3.77	3.96	4.16	4.37	4.59	4.82	5.07	5.32	5.59	5.88	6.17	6.48	6.81	7.16	7.52	7.90	8.30	329.24	8.71	320.52		9	7
				e					2.60	2.75	2.98	3.23	3.50	3.77	4.18	4.54	4.86	5.10	5.36	5.63	5.92	6.22	6.53	6.86	7.21	7.57	7.95	8.35	8.77	9.22	9.68	10.17	10.69	11.23	11.79	12.39	13.01		13.67		14.36		
8	10	Consol Ed	No	Yes	9.2%	32.5%	0.00	(75.26)	3.16	3.27	3.38	3.50	3.62	3.90	4.16	4.41	4.63	4.87	5.11	5.37	5.64	5.93	6.23	6.54	6.87	7.22	7.58	7.97	8.37	8.79	9.23	9.70	10.19	10.71	11.25	11.81	12.41	339.03	13.04	325.99		10	8
				e					4.25	4.55	4.70	4.85	5.00	5.15	5.53	5.89	6.23	6.54	6.87	7.22	7.58	7.97	8.37	8.79	9.24	9.70	10.19	10.71	11.25	11.82	12.41	13.04	13.70	14.39	15.12	15.88	16.68		17.52		18.41		
9	11	Dominion	Yes	No	10.5%	36.3%	0.00	(81.11)	3.86	3.95	4.05	4.15	4.25	4.58	4.90	5.20	5.46	5.74	6.03	6.33	6.65	6.98	7.34	7.71	8.10	8.51	8.94	9.39	9.86	10.36	10.88	11.43	12.01	12.62	13.25	13.92	14.63	597.02	15.36	581.66		11	9
				e					3.30	4.30	4.67	5.07	5.50	5.93	6.72	7.43	8.01	8.41	8.83	9.28	9.75	10.24	10.76	11.30	11.87	12.47	13.10	13.76	14.46	15.19	15.96	16.76	17.61	18.50	19.43	20.41	21.45		22.53		23.67		
10	12	DTE	Yes	No	9.8%	31.3%	0.00	(106.27)	4.42	4.67	4.93	5.20	5.47	6.03	6.55	6.99	7.34	7.71	8.10	8.51	8.94	9.39	9.87	10.36	10.89	11.44	12.01	12.62	13.26	13.93	14.63	15.37	16.15	16.96	17.82	18.72	19.66	548.52	20.66	527.87		12	10
				e					6.50	6.90	7.32	7.77	8.25	8.73	9.53	10.27	10.92	11.47	12.05	12.66	13.30	13.97	14.68	15.42	16.20	17.02	17.88	18.78	19.73	20.72	21.77	22.87	24.02	25.24	26.51	27.85	29.26		30.73		32.29		
11	13	Duke	Yes	No	9.4%	31.9%	0.00	(83.39)	3.89	3.96	4.03	4.10	4.17	4.45	4.72	4.99	5.24	5.50	5.78	6.07	6.38	6.70	7.04	7.40	7.77	8.16	8.57	9.01	9.46	9.94	10.44	10.97	11.52	12.11	12.72	13.36	14.03	391.29	14.74	376.55		13	11
									5.10	5.30	5.52	5.76	6.00	6.24	6.80	7.33	7.79	8.18	8.60	9.03	9.49	9.97	10.47	11.00	11.55	12.14	12.75	13.39	14.07	14.78	15.53	16.31	17.13	18.00	18.91	19.86	20.87		21.92		23.03		
12	16	Entergy	Yes	No	9.6%	34.6%	0.00	(97.05)	3.86	4.08	4.31	4.55	4.79	5.19	5.56	5.90	6.20	6.51	6.84	7.18	7.55	7.93	8.33	8.75	9.19	9.66	10.14	10.66	11.19	11.76	12.35	12.98	13.63	14.32	15.04	15.80	16.60	530.19	17.44	512.76		16	12
				e					5.05	5.80	6.18	6.57	7.00	7.43	7.99	8.52	9.03	9.48	9.96	10.46	10.99	11.55	12.13	12.74	13.39	14.06	14.77	15.52	16.30	17.13	17.99	18.90	19.85	20.86	21.91	23.02	24.18		25.40		26.68		
13	17	Evergy	Yes	No	For Future Use																																				17	13
				e																																						
14	18	Eversource	No	Yes	8.6%	44.8%	0.00	(82.56)	2.40	2.54	2.69	2.85	3.01	3.30	3.57	3.80	3.99	4.19	4.41	4.63	4.86	5.11	5.37	5.64	5.92	6.22	6.54	6.87	7.21	7.58	7.96	8.36	8.78	9.23	9.69	10.18	10.70	442.77	11.24	431.53		18	14
				e					3.65	3.85	4.13	4.43	4.75	5.07	5.58	6.05	6.45	6.78	7.12	7.48	7.86	8.26	8.67	9.11	9.57	10.06	10.56	11.10	11.66	12.25	12.86	13.51	14.20	14.91	15.67	16.46	17.29		18.16		19.08		
15	20	First Energy	Yes	No	10.3%	39.2%	0.00	(40.77)	1.61	1.70	1.80	1.90	2.00	2.17	2.33	2.48	2.60	2.73	2.87	3.02	3.17	3.33	3.50	3.67	3.86	4.05	4.26	4.47	4.70	4.94	5.18	5.45	5.72	6.01	6.31	6.63	6.97	301.30	7.32	293.98		20	15
				e					1.85	2.75	2.91	3.07	3.25	3.43	3.84	4.21	4.51	4.74	4.98	5.23	5.50	5.77	6.06	6.37	6.69	7.03	7.39	7.76	8.15	8.56	8.99	9.45	9.93	10.43	10.95	11.51	12.09		12.70		13.34		
16	24	IDACORP	Yes	No	8.6%	36.8%	0.00	(90.79)	2.93	3.12	3.33	3.55	3.77	4.16	4.51	4.82	5.06	5.32	5.59	5.87	6.17	6.48	6.80	7.15	7.51	7.89	8.29	8.71	9.15	9.61	10.09	10.60	11.14	11.70	12.29	12.91	13.56	400.97	14.25	386.72		24	16
				e					4.55	4.75	4.91	5.08	5.25	5.42	5.82	6.20	6.56	6.89	7.23	7.60	7.98	8.39	8.81	9.26	9.72	10.21	10.73	11.27	11.84	12.44	13.07	13.73	14.42	15.15	15.91	16.72	17.56		18.45		19.38		
17	26	NextEra	Yes	No	9.5%	47.8%	0.00	(242.28)	6.16	6.78	7.45	8.20	8.95	10.14	11.21	12.08	12.69	13.33	14.00	14.71	15.45	16.23	17.05	17.91	18.82	19.77	20.77	21.82	22.92	24.07	25.29	26.57	27.91	29.32	30.80	32.35	33.99	1,761.02	35.70	1,725.32		26	17
				e					7.50	9.80	10.63	11.53	12.50	13.47	15.22	16.79	18.07	18.98	19.94	20.95	22.00	23.11	24.28	25.51	26.80	28.15	29.57	31.06	32.63	34.28	36.01	37.83	39.74	41.75	43.86	46.07	48.40		50.84		53.41		
18	27	NorthWestern	Yes	No	9.4%	30.4%	0.00	(57.44)	2.50	2.60	2.70	2.80	2.90	3.14	3.37	3.58	3.76	3.95	4.15	4.35	4.57	4.81	5.05	5.30	5.57	5.85	6.15	6.46	6.78	7.13	7.49	7.86	8.26	8.68	9.12	9.58	10.06	257.06	10.57	246.49		27	18
				e					3.45	3.55	3.69	3.84	4.00	4.16	4.45	4.74	5.01	5.26	5.53	5.81	6.10	6.41	6.73	7.07	7.43	7.80	8.20	8.61	9.05	9.50	9.98	10.49	11.02	11.57	12.16	12.77	13.41		14.09		14.80		
19	28	OGE	Yes	Yes	10.8%	21.1%	0.00	(31.07)	1.68	1.77	1.86	1.95	2.04	2.25	2.43	2.59	2.72	2.86	3.01	3.16	3.32	3.48	3.66	3.85	4.04	4.24	4.46	4.68	4.92	5.17	5.43	5.70	5.99	6.29	6.61	6.95	7.30	141.54	7.66	133.88		28	19
				e					2.15	2.25	2.33	2.41	2.50	2.59	2.78	2.96	3.13	3.29	3.46	3.63	3.82	4.01	4.21	4.42	4.65	4.88	5.13	5.39	5.66	5.95	6.25	6.56	6.89	7.24	7.61	7.99	8.40		8.82		9.27		
20	29	Otter Tail	Yes	No	9.0%	35.5%	0.00	(42.03)	1.56	1.64	1.72	1.80	1.88	2.05	2.21	2.35	2.47	2.59	2.73	2.86	3.01	3.16	3.32	3.49	3.66	3.85	4.04	4.25	4.46	4.69	4.92	5.17	5.43	5.71	6.00	6.30	6.62	199.61	6.95	192.66		29	20
				e					2.05	2.20	2.30	2.40	2.50	2.60	2.81	3.00	3.18	3.34	3.51	3.69	3.87	4.07	4.27	4.49	4.71	4.95	5.20	5.47	5.74	6.03	6.34	6.66	6.99	7.35	7.72	8.11	8.52		8.95		9.40		
21	31	PGE	Yes	Yes	9.3%	32.7%	0.00	(45.24)	1.72	1.82	1.93	2.05	2.17	2.39	2.59	2.76	2.90	3.05	3.20	3.36	3.53	3.71	3.90	4.09	4.30	4.52	4.74	4.98	5.24	5.50	5.78	6.07	6.38	6.70	7.04	7.39	7.77	213.90	8.16	205.75		31	21
				e					2.50	2.65	2.76	2.88	3.00	3.12	3.38	3.62	3.85	4.04	4.24	4.46	4.68	4.92	5.17	5.43	5.70	5.99	6.30	6.61	6.95	7.30	7.67	8.05	8.46	8.89	9.34	9.81	10.30		10.82		11.37		
22	32	Pinnacle	Yes	Yes	10.0%	28.6%	0.00	(76.06)	3.41	3.60	3.79	4.00	4.21	4.62	4.99	5.32	5.59	5.87	6.17	6.48	6.81	7.15	7.51	7.89	8.29	8.71	9.15	9.61	10.09	10.60	11.14	11.70	12.29	12.91	13.57	14.25	14.97	385.38	15.73	369.66		32	22
				e					4.75	5.15	5.42	5.70	6.00	6.30	6.84	7.35	7.81	8.20	8.62	9.05	9.51	9.99	10.50	11.03	11.58	12.17	12.78	13.43	14.11	14.82	15.57	16.35	17.18	18.05	18.96	19.91	20.92		21.98		23.09		
23	33	PNM	Yes	No	9.3%	44.6%	0.00	(39.92)	1.30	1.36	1.43	1.50	1.57	1.72	1.86	1.98	2.08	2.19	2.30	2.42	2.54	2.67	2.80	2.94	3.09	3.25	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.06	5.31	5.58	255.60	5.86	249.74		33	23
				e					1.80	2.25	2.41	2.57	2.75	2.93	3.26	3.56	3.81	4.00	4.20	4.42	4.64	4.87	5.12	5.38	5.65	5.94	6.24	6.55	6.88	7.23	7.59	7.98	8.38	8.80	9.25	9.71	10.20		10.72		11.26		
24	34	PPL	Yes	No	10.9%	19.9%	0.00	(26.40)	1.67	1.71	1.76	1.80	1.84	1.96	2.08	2.20	2.31	2.43	2.55	2.68	2.81	2.95	3.10	3.26	3.42	3.60	3.78	3.97	4.17	4.38	4.60	4.83	5.08	5.33	5.60	5.89	6.18	118.39	6.50	111.89		34	24
				e					2.40	2.45	2.55	2.65	2.75	2.85	3.06	3.25	3.44	3.61	3.80	3.99	4.19	4.40	4.62	4.86	5.10	5.36	5.63	5.92	6.22	6.53	6.86	7.20	7.57	7.95	8.35	8.77	9.22		9.68		10.17		
25	38	Southern	Yes	No	9.7%	29.6%	0.00	(55.22)	2.62	2.70	2.78	2.86	2.94	3.16	3.37	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.04	5.30	5.56	5.85	6.14	6.45	6.78	7.12	7.48	7.86	8.25	8.67	9.11	9.57	10.05	261.26	10.56	250.70		38	25
				e					3.10	3.25	3.41	3.58	3.75	3.92	4.22	4.50	4.76	5.00	5.25	5.52	5.80	6.09	6.40	6.72	7.06	7.42	7.79	8.19	8.60	9.03	9.49	9.97	10.47	11.00	11.56	12.14	12.75		13.40		14.07		
26	40	WEC	No	Yes	8.6%	42.9%	(0.00)	(89.98)	2.70	2.86	3.02	3.20	3.38	3.71	4.02	4.29	4.51	4.73	4.97	5.22	5.49	5.77	6.06	6.36	6.68	7.02	7.38	7.75	8.14	8.55	8.98	9.44	9.91	10.41	10.94	11.49	12.07	462.73	12.68	450.05		40	26
				e					3.75	3.95	4.20	4.47	4.75	5.03	5.51	5.96	6.35	6.67	7.00	7.36	7.73	8.12	8.53	8.96	9.41	9.89	10.38	10.91	11.46	12.04	12.65	13.29	13.96	14.66	15.40	16.18	17.00		17.86		18.76		
27	42	Xcel	Yes	No	8.5%	45.0%	0.00	(63.70)	1.82	1.92	2.03	2.15	2.27	2.49	2.69	2.87	3.02	3.17	3.33	3.50	3.67	3.86	4.05	4.26	4.47	4.70	4.94	5.19	5.45	5.72	6.01	6.32	6.64	6.97	7.32	7.69	8.08	329.91	8.49	321.42		42	27
				e					2.75	2.90	3.09	3.29	3.50	3.71	4.07	4.40	4.69	4.93	5.18	5.44	5.72	6.01	6.31	6.63	6.96	7.31	7.68	8.07	8.48	8.91	9.36	9.83	10.33	10.85	11.39	11.97	12.57		13.21		13.88		

No. of Peers: 23 8

	Mean		
9.54%	35.03%	0.00%	Company Screen
9.26%	35.69%	0.00%	Staff Screen

Average B.O.Y. & E.O.Y. Cash Flows Model Y EPS Growth

	1	2	3	4	5	6	7	8	9		
	Screen #	Abbreviated Utility	UE 374 PAC	UE 374 Staff	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2017 - 2021 Dividend Growth Rates EOY	BOY	Average	Screen #	
1	1	Allete	Yes	No	9.9%	33.0%	4.1%	3.9%	4.0%	1	1
2	2	Alliant	Yes	Yes	9.0%	37.7%	7.1%	6.7%	6.9%	2	2
3	3	Ameren	Yes	Yes	8.4%	47.0%	5.1%	5.0%	5.1%	3	3
4	4	AEP	Yes	No	9.1%	36.7%	5.7%	5.7%	5.7%	4	4
5	6	Avista	Yes	No	9.4%	32.9%	4.1%	4.1%	4.1%	6	5
7	9	CMS	Yes	No	8.9%	43.5%	28.1%	7.2%	17.6%	9	7
8	10	Consol Ed	No	Yes	9.1%	33.4%	3.4%	3.4%	3.4%	10	8
9	11	Dominion	Yes	No	10.5%	37.2%	2.5%	2.4%	2.5%	11	9
10	12	DTE	Yes	No	9.7%	32.3%	6.0%	5.5%	5.7%	12	10
11	13	Duke	Yes	No	9.3%	32.6%	1.8%	1.8%	1.8%	13	11
12	16	Entergy	Yes	No	9.5%	35.6%	5.0%	5.6%	5.3%	16	12
13	17	Evergy	Yes	No	For Future Use					17	13
14	18	Eversource	No	Yes	8.5%	45.8%	5.9%	5.8%	5.8%	18	14
15	20	First Energy	Yes	No	10.2%	40.2%	4.9%	5.6%	5.2%	20	15
16	24	IDACORP	Yes	No	8.5%	37.8%	6.8%	6.5%	6.6%	24	16
17	26	NextEra	Yes	No	9.4%	49.0%	10.0%	9.8%	9.9%	26	17
18	27	NorthWestern	Yes	No	9.3%	31.3%	3.9%	3.8%	3.9%	27	18
19	28	OGE	Yes	Yes	10.6%	22.0%	5.1%	5.0%	5.1%	28	19
20	29	Otter Tail	Yes	No	8.9%	36.5%	5.0%	4.8%	4.9%	29	20
21	31	PGE	Yes	Yes	9.2%	33.7%	6.1%	5.9%	6.0%	31	21
22	32	Pinnacle	Yes	Yes	9.9%	29.6%	5.6%	5.4%	5.5%	32	22
23	33	PNM	Yes	No	9.2%	45.5%	4.9%	4.8%	4.9%	33	23
24	34	PPL	Yes	No	10.8%	20.6%	2.0%	2.5%	2.3%	34	24
25	38	Southern	Yes	No	9.6%	30.4%	3.0%	2.9%	3.0%	38	25
26	40	WEC	No	Yes	8.5%	43.9%	6.0%	5.7%	5.9%	40	26
27	42	Xcel	Yes	No	8.4%	46.0%	5.7%	5.6%	5.7%	42	27
		No. of Peers:	23	8		Mean					
					9.44%	35.96%	6.02%	Company Screen			
					9.16%	36.64%	5.52%	Staff Screen			

CASE: UE 374
WITNESSES: MATT MULDOON-
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CAPM DCF
Control Modeling

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CASE: UE 374
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MOYA ENRIGHT-
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PUBLIC UTILITY COMMISSION OF OREGON

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Gordon Growth - Single Stage DCF
ROE Control Modeling

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Long-Run GDP Growth Rates

Resource	10-Year GDP Projection	20-Year GDP Projection	30-Year GDP Projection	Date Accessed	Last Updated	Page
White House Budget, FY 2021, Table S-9, Economic Assumptions URL https://www.whitehouse.gov/wp-content/uploads/2020/02/budget_fy21.pdf	4.98 (N), 2.98 (Real)	N/A	N/A	6/25/2020	2/10/2020	126
CBO, The Budget and Economic Outlook: 2020-2030, Table 2-1 URL https://www.cbo.gov/system/files/2020-01/56020-CBO-Outlook.pdf	3.7 (N), 1.7 (Real)			6/25/2020	1/28/2020	30
SSA OASDI Trustee Report, Table V.B2, Additional Economic Factors URL https://www.ssa.gov/OACT/TR/2020/tr2020.pdf	2.0 (Real, FY 2030)	**1.9 (Real,** FY 2040)	**2.0 (Real,** FY 2050)	6/25/2020	4/22/2020	114
	Note: Using intermediate measure, low cost and high cost available					
EIA Assumptions to **Annual Energy Outlook 2020**, Table 1, Economic growth in gross domestic product URL https://www.eia.gov/outlooks/aeo/assumptions/pdf/macroeconomic.pdf	1.9% (Real)	1.8% Real	1.8% Real	6/25/2020	1/29/2020	1
	Note: Using intermediate measure, low cost and high cost available					
EIA Annual Energy Outlook 2020, **Critical drivers and model updates** URL https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf	N/A	N/A	1.4%, **1.9%**, 2.4% (Real, FY 2050)	6/25/2020	1/29/2020	20
	Note: Measures shown are for Low economic growth, **Reference** case, and High economic growth (respectively)					
BLS, Projections Overview and Highlights, **2018-28**, Figure 5 URL https://www.bls.gov/opub/mlr/2019/article/projections-overview-and-highlights-2018-28.htm	1.8 (Real, FY 2028)	N/A	N/A	6/25/2020	10/1/2019	N/A
PwC, The Long View, Table B2, Breakdown of…average real growth in GPD at MERs (**2016-2050**) URL https://www.pwc.com/gx/en/world-2050/assets/pwc-the-world-in-2050-full-report-feb-2017.pdf	N/A	N/A	**1.8% (Real,** FY 2050)	6/25/2020	2/1/2017	69
Fidelity, Secular Outlook for Global Growth: The Next 20 Years, Exhibit 6 URL https://institutional.fidelity.com/app/proxy/content?literatureURL=/959546.PDF	N/A	**1.7% (Real,** FY 2038)	N/A	6/25/2020	5/31/2019	8

Acronyms Used	
BLS	Bureau of Labor Statistics
CBO	Congressional Budget Office
EIA	Energy Information Administration
FY	Fiscal Year
GDP	Gross Domestic Product
MERs	Market Exchange Rates
N	Nominal
N/A	Not Available
OASDI	Old Age Survivors Disability Insurance (Socal Security)
PwC	PricewaterhouseCooper
R	Real
SSA	Social Security Administration

CASE: UE 374
WITNESSES: MATT MULDOON-
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STAFF EXHIBIT 1907
Long-Run Projected Growth Rates

Exhibits in Support of Rebuttal Testimony

July 24, 2020

Page 1 of

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FISCAL YEAR 2021

A BUDGET FOR AMERICA'S FUTURE

BUDGET OF THE U.S. GOVERNMENT

OFFICE OF MANAGEMENT AND BUDGET | OMB.GOV

Long-Run GDP Growth Rates

Table S–9. Economic Assumptions[1]

(Calendar years)

	Actual 2018	Projections 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gross Domestic Product (GDP):													
Nominal level, billions of dollars	20,580	21,437	22,494	23,645	24,849	26,113	27,442	28,822	30,242	31,719	33,269	34,893	36,598
Percent change, nominal GDP, year/year	5.4	4.2	4.9	5.1	5.1	5.1	5.1	5.0	4.9	4.9	4.9	4.9	4.9
Real GDP, percent change, year/year	2.9	2.4	2.8	3.1	3.0	3.0	3.0	3.0	2.9	2.8	2.8	2.8	2.8
Real GDP, percent change, Q4/Q4	2.5	2.5	3.1	3.0	3.0	3.0	3.0	2.9	2.8	2.8	2.8	2.8	2.8
GDP chained price index, percent change, year/year	2.4	1.8	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Consumer Price Index,[2] percent change, year/year	2.4	1.8	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Interest rates, percent:[3]													
91-day Treasury bills[4]	1.9	2.1	1.4	1.5	1.5	1.6	1.7	2.0	2.2	2.4	2.5	2.5	2.5
10-year Treasury notes	2.9	2.2	2.0	2.2	2.5	2.7	3.0	3.1	3.1	3.1	3.2	3.2	3.2
Unemployment rate, civilian, percent[3]	3.9	3.7	3.5	3.6	3.8	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0

Note: A more detailed table of economic assumptions appears in Chapter 2, "Economic Assumptions and Interactions with the Budget," in the *Analytical Perspectives* volume of the Budget.

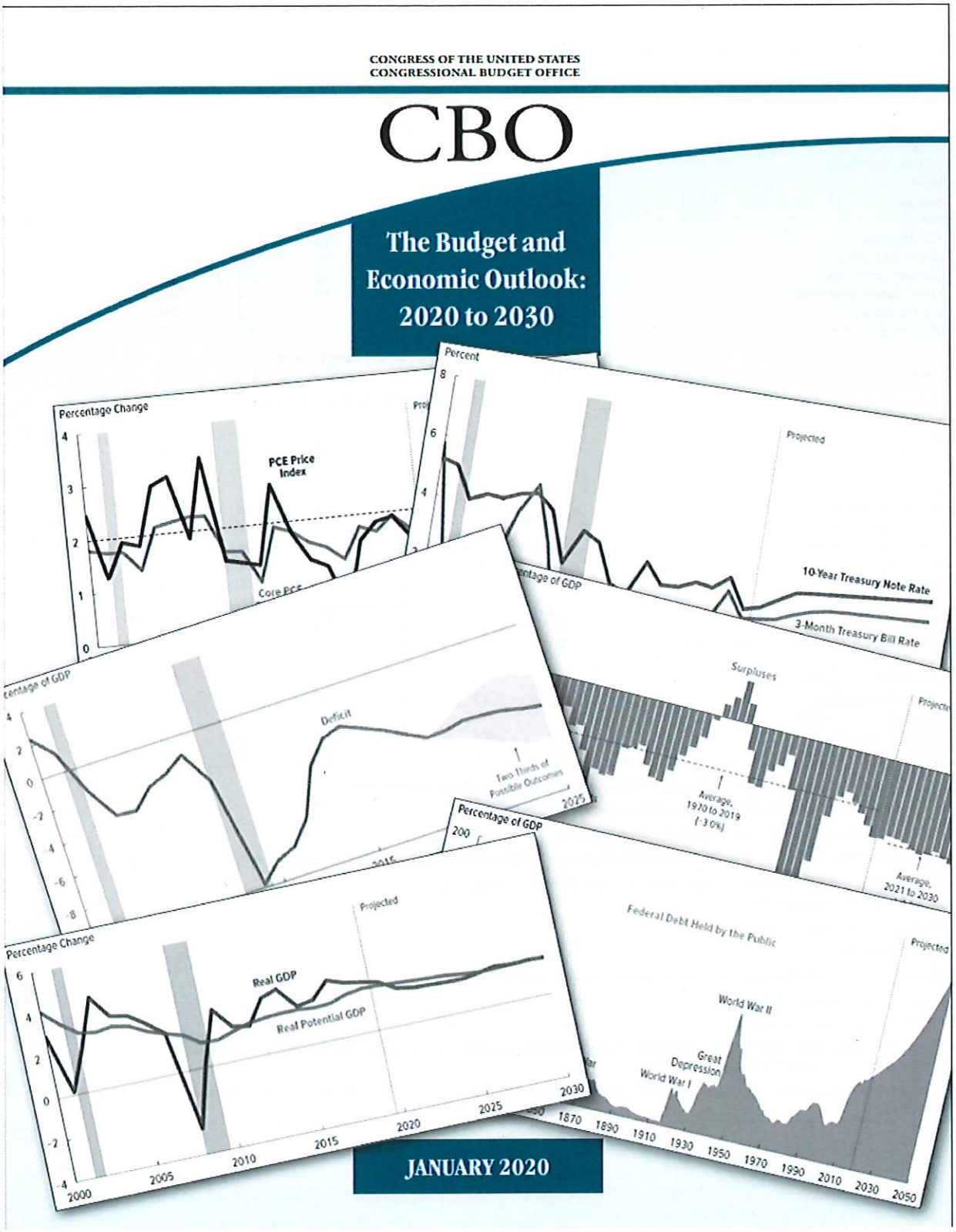
[1] Based on information available as of mid-November 2019.

[2] Seasonally adjusted CPI for all urban consumers.

[3] Annual average.

[4] Average rate, secondary market (bank discount basis).

Long-Run GDP Growth Rates



Long-Run GDP Growth Rates

Table 2-1.

CBO's Economic Projections for Calendar Years 2020 to 2030

	Estimated, 2019[a]	2020	2021	2022	Annual Average 2023–2024	Annual Average 2025–2030
	Percentage Change From Fourth Quarter to Fourth Quarter					
Gross Domestic Product						
Real[b]	2.4	2.2	1.8	1.6	1.6	1.7
Nominal	4.2	4.2	3.9	3.8	3.7	3.7
Inflation						
PCE price index	1.5	2.0	2.1	2.1	2.0	1.9
Core PCE price index[c]	1.7	2.2	2.1	2.0	2.0	1.9
Consumer price index[d]	2.0[e]	2.5	2.6	2.6	2.4	2.2
Core consumer price index[c]	2.3[e]	2.8	2.6	2.5	2.4	2.2
GDP price index	1.8	1.9	2.1	2.1	2.1	2.0
Employment Cost Index[f]	3.1	3.6	3.6	3.6	3.4	3.1
	Fourth-Quarter Level (Percent)					
Unemployment Rate	3.5[e]	3.5	3.6	4.0	4.4[g]	4.4[h]
	Percentage Change From Year to Year					
Gross Domestic Product						
Real[b]	2.3	2.2	1.9	1.7	1.6	1.7
Nominal	4.2	4.2	4.1	3.8	3.7	3.7
Inflation						
PCE price index	1.4	1.9	2.1	2.1	2.0	1.9
Core PCE price index[c]	1.6	2.0	2.2	2.1	2.0	1.9
Consumer price index[d]	1.8[e]	2.4	2.5	2.6	2.4	2.3
Core consumer price index[c]	2.2[e]	2.7	2.6	2.5	2.4	2.2
GDP price index	1.8	1.9	2.1	2.1	2.1	2.0
Employment Cost Index[f]	3.0	3.5	3.6	3.6	3.5	3.1
	Annual Average					
Unemployment Rate (Percent)	3.7[e]	3.5	3.5	3.8	4.3	4.5
Payroll Employment (Monthly change, in thousands)[i]	181[e]	135	59	17	17	51
Interest Rates (Percent)						
Three-month Treasury bills	2.1[e]	1.6	1.7	1.8	2.1	2.3
Ten-year Treasury notes	2.1[e]	1.9	2.2	2.6	2.7	3.0
Tax Bases (Percentage of GDP)						
Wages and salaries	43.5	43.7	43.8	43.9	43.9	43.8
Domestic corporate profits[j]	7.2	7.6	7.7	7.7	7.8	7.8

Sources: Congressional Budget Office; Bureau of Economic Analysis; Bureau of Labor Statistics; Federal Reserve.

For economic projections for each year from 2020 to 2030, see Appendix B.

GDP = gross domestic product; PCE = personal consumption expenditures.

a. Values for 2019 do not reflect the values for GDP and related series that the Bureau of Economic Analysis has released since early January 2020.

b. Real values are nominal values that have been adjusted to remove the effects of changes in prices.

c. Excludes prices for food and energy.

d. The consumer price index for all urban consumers.

e. Actual value for 2019.

f. The employment cost index for wages and salaries of workers in private industry.

g. Value for the fourth quarter of 2024.

h. Value for the fourth quarter of 2030.

i. The average monthly change in the number of employees on nonfarm payrolls, calculated by dividing the change from the fourth quarter of one calendar year to the fourth quarter of the next by 12.

j. Adjusted to remove distortions in depreciation allowances caused by tax rules and to exclude the effects of changes in prices on the value of inventories.

THE 2020 ANNUAL REPORT OF THE BOARD OF TRUSTEES OF THE FEDERAL OLD-AGE AND SURVIVORS INSURANCE AND FEDERAL DISABILITY INSURANCE TRUST FUNDS

COMMUNICATION

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THE BOARD OF TRUSTEES, FEDERAL OLD-AGE AND SURVIVORS INSURANCE AND FEDERAL DISABILITY INSURANCE TRUST FUNDS

TRANSMITTING

THE 2020 ANNUAL REPORT OF THE BOARD OF TRUSTEES OF THE FEDERAL OLD-AGE AND SURVIVORS INSURANCE AND FEDERAL DISABILITY INSURANCE TRUST FUNDS

Long-Run GDP Growth Rates

Assumptions and Methods

Table V.B2.—Additional Economic Factors (Cont.)

Calendar year	Average annual unemployment rate[a]	Annual percentage change[b] in— Labor force[c]	Total employment[d]	Real GDP[e]	Average annual interest rate Nominal[f]	Real[g]
Intermediate:						
2020	3.8	1.1	0.9	2.1	2.3	[h]
2021	4.2	.7	.3	2.3	2.9	-.1
2022	4.6	.8	.3	2.2	3.3	.5
2023	5.0	.8	.4	2.1	3.6	.9
2024	5.0	.6	.6	2.1	4.0	1.2
2025	5.0	.5	.5	2.1	4.2	1.6
2026	5.0	.5	.5	2.1	4.4	1.8
2027	5.0	.5	.5	2.1	4.6	2.0
2028	5.0	.5	.5	2.1	4.6	2.2
2029	5.0	.5	.5	2.1	4.7	2.2
2030	5.0	.4	.4	2.0	4.7	2.3
2035	5.0	.4	.4	2.0	4.7	2.3
2040	5.0	.3	.3	1.9	4.7	2.3
2045	5.0	.4	.4	2.0	4.7	2.3
2050	5.0	.5	.5	2.0	4.7	2.3
2055	5.0	.4	.4	2.0	4.7	2.3
2060	5.0	.4	.4	2.0	4.7	2.3
2065	5.0	.3	.3	1.9	4.7	2.3
2070	5.0	.3	.3	1.9	4.7	2.3
2075	5.0	.4	.4	2.0	4.7	2.3
2080	5.0	.4	.4	2.0	4.7	2.3
2085	5.0	.4	.4	2.0	4.7	2.3
2090	5.0	.4	.4	2.0	4.7	2.3
2095	5.0	.4	.4	1.9	4.7	2.3
Low-cost:						
2020	3.7	1.5	1.5	3.2	3.3	-.7
2021	3.9	1.2	.9	3.6	3.8	.4
2022	4.0	.8	.7	3.1	4.4	.9
2023	4.0	.8	.8	2.8	4.7	1.4
2024	4.0	.8	.7	2.8	5.0	1.7
2025	4.0	.7	.7	2.7	5.3	2.0
2026	4.0	.7	.7	2.7	5.5	2.3
2027	4.0	.6	.6	2.6	5.6	2.5
2028	4.0	.6	.6	2.6	5.8	2.6
2029	4.0	.6	.6	2.6	5.8	2.8
2030	4.0	.5	.5	2.5	5.8	2.8
2035	4.0	.5	.5	2.5	5.8	2.8
2040	4.0	.5	.5	2.5	5.8	2.8
2045	4.0	.7	.6	2.6	5.8	2.8
2050	4.0	.7	.7	2.7	5.8	2.8
2055	4.0	.7	.7	2.7	5.8	2.8
2060	4.0	.6	.6	2.6	5.8	2.8
2065	4.0	.6	.6	2.6	5.8	2.8
2070	4.0	.6	.6	2.6	5.8	2.8
2075	4.0	.7	.7	2.7	5.8	2.8
2080	4.0	.7	.7	2.7	5.8	2.8
2085	4.0	.7	.7	2.7	5.8	2.8
2090	4.0	.7	.7	2.7	5.8	2.8
2095	4.0	.6	.6	2.6	5.8	2.8

Macroeconomic Activity Module

Long-Run GDP Growth Rates

Table 1. Economic growth in gross domestic product (GDP), nonfarm employment, and productivity

Assumptions	2019–2020	2021–2030	2031–2040	2041–2050	2019–2050
Real GDP (billion chain–weighted $2009)					
High Economic Growth	2.4%	2.3%	2.3%	2.5%	2.4%
Reference	1.9%	1.9%	1.8%	1.8%	1.9%
Low Economic Growth	1.4%	1.4%	1.4%	1.3%	1.4%
Nonfarm Employment					
High Economic Growth	1.4%	0.6%	0.7%	0.9%	0.8%
Reference	1.1%	0.4%	0.6%	0.5%	0.5%

Low Economic Growth	0.8%	0.1%	0.4%	0.3%	0.3%
Productivity					
High Economic Growth	1.5%	2.1%	1.8%	1.9%	1.9%
Reference	1.0%	1.8%	1.4%	1.4%	1.5%
Low Economic Growth	0.7%	1.5%	1.0%	1.1%	1.2%

Source: U.S. Energy Information Administration, AEO2020 National Energy Modeling System runs: ref2020.d112119a, lowmacro.d112619a, and highmacro.d112619a.

Annual Energy Outlook 2020

with projections to 2050

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January 29, 2020
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Annual Energy Outlook 2020
with projections to 2050

January 2020

U.S. Energy Information Administration
Office of Energy Analysis
U.S. Department of Energy
Washington, DC 20585

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Long-Run GDP Growth Rates

—which also affect important drivers of energy demand growth

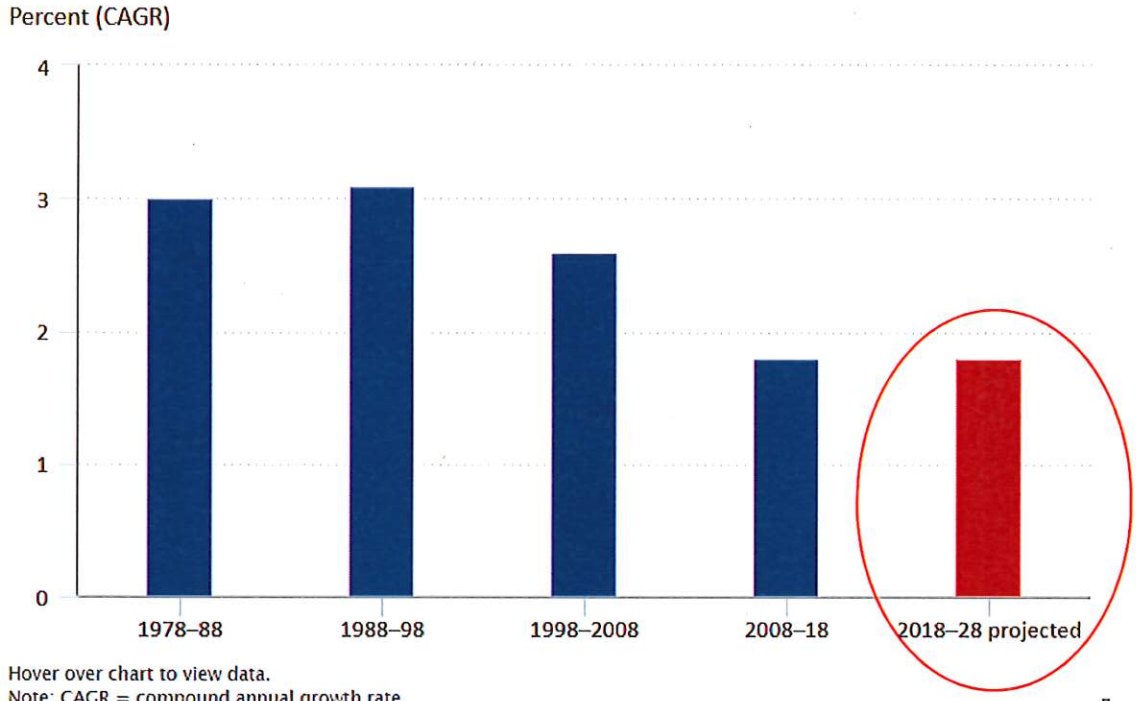
- The AEO2020 Reference, High Economic Growth, and Low Economic Growth cases illustrate three possible paths for U.S. economic growth. In the High Economic Growth case, average annual growth in real GDP during the projection period is 2.4% compared with 1.9% in the Reference case. The Low Economic Growth case assumes a lower rate of annual growth in real GDP of 1.4%.
- Differences among the cases reflect different assumptions for growth in the labor force, capital stock, and productivity. These changes affect capital investment decisions, household formation, industrial activity, and amount of travel.
- All three economic growth cases assume smooth economic growth and do not anticipate business cycles or large economic shocks.

Long-Run GDP Growth Rates

Monthly Labor Review

Long-Run GDP Growth Rates

Figure 5. Gross domestic product, 10-year CAGR, 1978–2018 and projected 2018–28



Hover over chart to view data.
Note: CAGR = compound annual growth rate.
Source: U.S. Bureau of Labor Statistics.

The Long View
How will the global economic order change by 2050?

February 2017

pwc

Long-Run GDP Growth Rates

Table B2: Breakdown of components of average real growth in GDP at MERs (2016-2050)

Country	Average Pop Growth p.a %	Average Real Growth per capita p.a %	% of growth due to MER	Average GDP growth p.a. (in USD)
India	0.7%	4.1%	2.8%	7.7%
Vietnam	0.5%	4.5%	2.4%	7.4%
Bangladesh	0.6%	4.1%	2.2%	7.0%
Pakistan	1.4%	2.9%	2.6%	7.0%
Egypt	1.4%	2.6%	2.5%	6.6%
Philippines	1.1%	3.1%	2.1%	6.3%
Nigeria	2.3%	1.9%	2.1%	6.2%
Indonesia	0.6%	3.1%	2.5%	6.2%
South Africa	0.5%	3.2%	2.1%	5.8%
Malaysia	0.8%	2.7%	2.3%	5.8%
Iran	0.4%	2.5%	2.6%	5.5%
Colombia	0.4%	2.9%	2.0%	5.3%
Saudi Arabia	1.1%	1.9%	2.2%	5.1%
Mexico	0.7%	2.5%	1.7%	5.0%
Thailand	-0.3%	2.9%	2.3%	4.9%
Turkey	0.5%	2.4%	1.8%	4.8%
Poland	-0.4%	2.5%	2.5%	4.5%
China	-0.1%	3.1%	1.4%	4.4%
Russia	-0.3%	2.2%	2.3%	4.2%
Argentina	0.7%	2.2%	1.1%	4.1%
Brazil	0.4%	2.2%	1.3%	3.9%
South Korea	0.0%	1.8%	1.0%	2.8%
Spain	-0.1%	1.5%	0.9%	2.3%
Australia	0.9%	1.3%	-0.2%	2.1%
United Kingdom	0.4%	1.5%	0.2%	2.1%
Canada	0.6%	1.2%	0.3%	2.1%
Netherlands	0.1%	1.5%	0.4%	2.0%
France	0.3%	1.3%	0.3%	1.9%
United States	0.5%	1.3%	0.0%	1.8%
Germany	-0.2%	1.5%	0.4%	1.7%
Italy	-0.2%	1.2%	0.5%	1.5%
Japan	-0.5%	1.4%	0.1%	1.1%

Source: PwC analysis

LEADERSHIP SERIES

Secular Outlook for Global Growth: The Next 20 Years

Slower economic growth is expected to result in a lower-than-historical-average interest rate climate and to offer less of a tailwind to equities

Irina Tytell, PhD | Senior Research Analyst, Asset Allocation Research
Lisa Emsbo-Mattingly | Director of Asset Allocation Research
Dirk Hofschire, CFA | Senior Vice President, Asset Allocation Research

Long-Run GDP Growth Rates

EXHIBIT 6: The world economy will grow more slowly, with the highest growth rates found in developing economies.

Real GDP 20-Year Growth Forecasts vs. History, 2019–2038

CASE: UE 374
WITNESSES: MATT MULDOON-
MOYA ENRIGHT-
CURTIS DLOUHY

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1908
BEA Historic GDP Growth Rate

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Bureau of Economic Analysis (BEA)

Current-Dollar and "Real" Gross Domestic Product (GDP)

Staff Accessed June 25, 2020

Data Recompiled by BEA on May 28, 2020

Annual

http://www.bea.gov/national/index.htm

Quarterly https://www.bea.gov/data/economic-accounts/national

(Seasonally adjusted annual rates)

Yr	GDP in billions of current dollars	GDP in billions of chained 2012 dollars
1929	104.556	1109.448
1930	92.16	1015.058
1931	77.391	950.037
1932	59.522	827.495
1933	57.154	817.265
1934	66.8	905.594
1935	74.241	986.231
1936	84.83	1113.291
1937	93.003	1170.344
1938	87.352	1131.564
1939	93.437	1222.375
1940	102.899	1330.151
1941	129.309	1565.778
1942	165.952	1861.5
1943	203.084	2178.39
1944	224.447	2351.627
1945	228.007	2328.626
1946	227.535	2058.375
1947	249.616	2034.814
1948	274.468	2118.512
1949	272.475	2106.559
1950	299.827	2289.546
1951	346.914	2473.758
1952	367.341	2574.898
1953	389.218	2695.614
1954	390.549	2680.023
1955	425.478	2871.198
1956	449.353	2932.388
1957	474.039	2994.132
1958	481.229	2971.951
1959	521.654	3178.182
1960	542.382	3259.971
1961	562.21	3343.546
1962	603.921	3548.409
1963	637.451	3702.944
1964	684.46	3916.28
1965	742.289	4170.75
1966	813.414	4445.853
1967	859.958	4567.781
1968	940.651	4792.315
1969	1017.615	4942.067
1970	1073.303	4951.262
1971	1164.85	5114.325
1972	1279.11	5383.282
1973	1425.376	5687.207
1974	1545.243	5656.465
1975	1684.904	5644.843
1976	1873.412	5948.995
1977	2081.826	6224.086
1978	2351.599	6568.608
1979	2627.334	6776.58
1980	2857.307	6759.181
1981	3207.042	6930.71
1982	3343.789	6805.758
1983	3634.038	7117.729
1984	4037.613	7632.812
1985	4338.979	7951.074
1986	4579.631	8226.392
1987	4855.215	8510.99
1988	5236.438	8866.498
1989	5641.58	9192.134
1990	5963.144	9365.494
1991	6158.129	9355.355
1992	6520.327	9684.892
1993	6858.559	9951.502
1994	7287.236	10352.432
1995	7639.749	10630.321
1996	8073.122	11031.35
1997	8577.552	11521.938
1998	9062.817	12038.283
1999	9630.663	12610.491
2000	10252.347	13130.987
2001	10581.822	13262.079
2002	10936.418	13493.064
2003	11458.246	13879.129
2004	12213.73	14406.382
2005	13036.637	14912.509
2006	13814.609	15338.257
2007	14451.86	15626.029
2008	14712.845	15604.687
2009	14448.932	15208.834
2010	14992.052	15598.753
2011	15542.582	15840.664
2012	16197.007	16197.007
2013	16784.851	16495.369
2014	17527.258	16912.038
2015	18224.78	17403.843
2016	18715.04	17688.89
2017	19519.424	18108.082
2018	20580.223	18638.164
2019	21427.69	19073.056

Quarter	GDP in billions of current dollars	GDP in billions of chained 2012 dollars	Qtr#
1947Q1	243.164	2033.061	1
1947Q2	245.968	2027.639	2
1947Q3	249.585	2023.452	3
1947Q4	259.745	2055.103	4
1948Q1	265.742	2086.017	5
1948Q2	272.567	2120.450	6
1948Q3	279.196	2132.598	7
1948Q4	280.366	2134.981	8
1949Q1	275.034	2105.562	9
1949Q2	271.351	2098.380	10
1949Q3	272.889	2120.044	11
1949Q4	270.627	2102.251	12
1950Q1	280.828	2184.872	13
1950Q2	290.383	2251.507	14
1950Q3	308.153	2338.514	15
1950Q4	319.945	2383.291	16
1951Q1	336.000	2415.660	17
1951Q2	344.090	2457.517	18
1951Q3	351.385	2508.166	19
1951Q4	356.178	2513.690	20
1952Q1	359.820	2540.550	21
1952Q2	361.030	2546.022	22
1952Q3	367.701	2564.401	23
1952Q4	380.812	2648.621	24
1953Q1	387.980	2697.855	25
1953Q2	391.749	2718.709	26
1953Q3	391.171	2703.411	27
1953Q4	385.970	2662.482	28
1954Q1	385.345	2649.755	29
1954Q2	386.121	2652.643	30
1954Q3	390.996	2682.601	31
1954Q4	399.734	2735.091	32
1955Q1	413.073	2813.212	33
1955Q2	421.532	2858.988	34
1955Q3	430.221	2897.598	35
1955Q4	437.092	2914.993	36
1956Q1	439.746	2903.671	37
1956Q2	446.010	2927.665	38
1956Q3	451.191	2925.035	39
1956Q4	460.463	2973.179	40
1957Q1	469.779	2992.219	41
1957Q2	472.025	2985.663	42
1957Q3	479.490	3014.919	43
1957Q4	474.864	2983.727	44
1958Q1	467.540	2906.274	45
1958Q2	471.978	2925.379	46
1958Q3	485.841	2993.068	47
1958Q4	499.555	3063.085	48
1959Q1	510.330	3121.936	49
1959Q2	522.653	3192.380	50
1959Q3	525.034	3194.653	51
1959Q4	528.600	3203.759	52
1960Q1	542.648	3275.757	53
1960Q2	541.080	3258.088	54
1960Q3	545.604	3274.029	55
1960Q4	540.197	3232.009	56
1961Q1	545.018	3253.826	57
1961Q2	555.545	3309.059	58
1961Q3	567.664	3372.581	59
1961Q4	580.612	3438.721	60
1962Q1	594.013	3500.054	61
1962Q2	600.366	3531.683	62
1962Q3	609.027	3575.070	63
1962Q4	612.280	3586.827	64
1963Q1	621.672	3625.981	65
1963Q2	629.752	3666.669	66
1963Q3	644.444	3747.278	67
1963Q4	653.938	3771.845	68
1964Q1	669.822	3851.366	69
1964Q2	678.674	3893.296	70
1964Q3	692.031	3954.121	71
1964Q4	697.319	3966.335	72
1965Q1	717.790	4062.311	73
1965Q2	730.191	4113.629	74
1965Q3	749.323	4205.086	75
1965Q4	771.857	4301.973	76
1966Q1	795.734	4406.693	77
1966Q2	804.981	4421.747	78
1966Q3	819.638	4459.195	79
1966Q4	833.302	4495.777	80
1967Q1	844.170	4535.591	81
1967Q2	848.983	4538.370	82
1967Q3	865.233	4581.309	83
1967Q4	881.439	4615.853	84
1968Q1	909.387	4709.993	85
1968Q2	934.344	4788.688	86
1968Q3	950.825	4825.799	87
1968Q4	968.030	4844.779	88
1969Q1	993.337	4920.605	89
1969Q2	1009.020	4935.564	90
1969Q3	1029.956	4968.164	91
1969Q4	1038.147	4943.935	92
1970Q1	1051.200	4936.594	93
1970Q2	1067.375	4943.600	94
1970Q3	1086.059	4989.159	95
1970Q4	1088.608	4935.693	96
1971Q1	1135.156	5069.746	97
1971Q2	1156.271	5097.179	98
1971Q3	1177.675	5139.128	99
1971Q4	1190.297	5151.245	100
1972Q1	1230.609	5245.974	101
1972Q2	1266.369	5365.045	102
1972Q3	1290.566	5415.712	103
1972Q4	1328.904	5506.396	104
1973Q1	1377.490	5642.669	105
1973Q2	1413.887	5704.098	106
1973Q3	1433.838	5674.100	107
1973Q4	1476.289	5727.960	108
1974Q1	1491.209	5678.713	109
1974Q2	1530.056	5692.210	110
1974Q3	1560.026	5638.411	111
1974Q4	1599.679	5616.526	112
1975Q1	1616.116	5548.156	113
1975Q2	1651.853	5587.800	114
1975Q3	1709.820	5683.444	115
1975Q4	1761.831	5759.972	116
1976Q1	1820.487	5889.500	117
1976Q2	1852.332	5932.711	118
1976Q3	1886.558	5965.265	119
1976Q4	1934.273	6008.504	120
1977Q1	1988.648	6079.494	121
1977Q2	2055.909	6197.686	122
1977Q3	2118.473	6309.514	123
1977Q4	2164.270	6309.652	124
1978Q1	2202.760	6329.791	125
1978Q2	2331.633	6574.390	126
1978Q3	2395.053	6640.497	127
1978Q4	2476.949	6729.755	128
1979Q1	2526.610	6741.854	129
1979Q2	2591.247	6749.063	130
1979Q3	2667.565	6799.200	131
1979Q4	2723.883	6816.203	132
1980Q1	2789.842	6837.641	133
1980Q2	2797.352	6696.753	134
1980Q3	2856.483	6688.794	135
1980Q4	2985.557	6813.535	136
1981Q1	3124.206	6947.042	137
1981Q2	3162.532	6895.559	138
1981Q3	3260.609	6978.135	139
1981Q4	3280.818	6902.105	140

1980 through 2020 Q1

Average 2.58% Real

1	8.830198	1980
2	8.809378	
3	8.808189	
4	8.826666	
5	8.846071	1981
6	8.838633	
7	8.850537	
8	8.839582	
9	8.823924	1982
10	8.828476	
11	8.824646	
12	8.825045	
13	8.838137	1983
14	8.860638	
15	8.880432	
16	8.901080	
17	8.920439	1984
18	8.937569	
19	8.947163	
20	8.955339	
21	8.964983	1985
22	8.973749	
23	8.988905	
24	8.996310	
25	9.005602	1986
26	9.010096	
27	9.019620	
28	9.024977	
29	9.032401	1987
30	9.043132	
31	9.051771	
32	9.068795	
33	9.073948	1988
34	9.087002	
35	9.092844	
36	9.106081	
37	9.116195	1989
38	9.123799	
39	9.131181	
40	9.133149	
41	9.144018	1990
42	9.147640	
43	9.148305	
44	9.139160	
45	9.134470	1991
46	9.142237	
47	9.147278	
48	9.150756	
49	9.162656	1992
50	9.173441	
51	9.183275	
52	9.193653	
53	9.195326	1993
54	9.201133	
55	9.205895	
56	9.219404	
57	9.229059	1994
58	9.242519	
59	9.248347	
60	9.259737	
61	9.263278	1995
62	9.266257	
63	9.274728	
64	9.281496	
65	9.288957	1996
66	9.305498	
67	9.314428	
68	9.324758	
69	9.331193	1997
70	9.347677	
71	9.360107	
72	9.368659	
73	9.378604	1998
74	9.387820	
75	9.400267	
76	9.416297	
77	9.425717	1999
78	9.433379	
79	9.446391	
80	9.463244	
81	9.466855	2000
82	9.485001	
83	9.486336	
84	9.492545	
85	9.489690	2001
86	9.495518	
87	9.491359	
88	9.494079	
89	9.502786	2002
90	9.508825	
91	9.513261	
92	9.514808	
93	9.520341	2003
94	9.528906	
95	9.545746	
96	9.557162	
97	9.562485	2004
98	9.570077	
99	9.579486	
100	9.589453	
101	9.600462	2005
102	9.605067	
103	9.613941	
104	9.620235	
105	9.633451	2006
106	9.635785	
107	9.637330	
108	9.645813	
109	9.648165	2007
110	9.653877	
111	9.659295	
112	9.665355	
113	9.659592	2008
114	9.664742	
115	9.659314	
116	9.637438	
117	9.626148	2009
118	9.624707	
119	9.628341	
120	9.639265	
121	9.643106	2010
122	9.652284	
123	9.659629	
124	9.664635	
125	9.662228	2011
126	9.669352	
127	9.669074	
128	9.680601	
129	9.688400	2012
130	9.692693	
131	9.694041	
132	9.695180	
133	9.703997	2013
134	9.705230	
135	9.713034	
136	9.720985	
137	9.718154	2014
138	9.731600	
139	9.743735	
140	9.749347	

Long Run Historical GDP Growth Rate

OLD

Annualized Real LN GPD Q

2.72%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.988949024
R Square	0.978020173
Adjusted R Square	0.977881935
Standard Error	0.047273755
Observations	161

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	15.81105564	15.81105564	7074.905862	9.9141E-134
Residual	159	0.355334459	0.002234808		
Total	160	16.1663901			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.845121901	0.007486235	1181.518136	0	8.830336616	8.859907186	8.830336616	8.859907186
X Variable 1	**0.006742805**	8.01642E-05	84.11245961	9.9141E-134	0.006584481	0.006901129	0.006584481	0.006901129

GDP is an array of expenditure and income data collected by BEA directly and through other government agencies.

Note **July 31, 2013, 14th Comprehensive Significant Revision:**
BEA revised its tables back to 1929 in to order to count:
1 Artistic Works
2 Research and Development
as Capital Investments that Depreciate Over Time rather than one time expenditures

From an Economy based on
(Industry and Manufacturing)
to one based on
(Knowledge and Information)

This comprehensive revision did not cause a large percentage jump.
The relative difference of actual amounts over time changed little.

1982Q1	3274.302	6794.878	141
1982Q2	3331.972	6825.876	142
1982Q3	3366.322	6799.781	143
1982Q4	3402.561	6802.497	144
1983Q1	3473.413	6892.144	145
1983Q2	3578.848	7048.982	146
1983Q3	3689.179	7189.896	147
1983Q4	3794.706	7339.893	148
1984Q1	3908.054	7483.371	149
1984Q2	4009.601	7612.668	150
1984Q3	4084.250	7686.059	151
1984Q4	4148.551	7749.151	152
1985Q1	4230.168	7824.247	153
1985Q2	4294.887	7893.136	154
1985Q3	4386.773	8013.674	155
1985Q4	4444.094	8073.239	156
1986Q1	4507.894	8148.603	157
1986Q2	4545.340	8185.303	158
1986Q3	4607.669	8263.639	159
1986Q4	4657.627	8308.021	160
1987Q1	4722.156	8369.930	161
1987Q2	4806.160	8460.233	162
1987Q3	4884.555	8533.635	163
1987Q4	5007.994	8680.162	164
1988Q1	5073.372	8725.006	165
1988Q2	5190.036	8839.641	166
1988Q3	5282.835	8891.435	167
1988Q4	5399.509	9009.913	168
1989Q1	5511.253	9101.508	169
1989Q2	5612.463	9170.977	170
1989Q3	5695.365	9238.923	171
1989Q4	5747.237	9257.128	172
1990Q1	5872.701	9358.289	173
1990Q2	5960.028	9392.251	174
1990Q3	6015.116	9398.499	175
1990Q4	6004.733	9312.937	176
1991Q1	6035.178	9269.367	177
1991Q2	6126.862	9341.642	178
1991Q3	6205.937	9388.845	179
1991Q4	6264.540	9421.565	180
1992Q1	6363.102	9534.346	181
1992Q2	6470.763	9637.732	182
1992Q3	6566.641	9732.979	183
1992Q4	6680.803	9834.510	184
1993Q1	6729.459	9850.973	185
1993Q2	6808.939	9908.347	186
1993Q3	6882.098	9955.641	187
1993Q4	7013.738	10091.049	188
1994Q1	7115.652	10188.954	189
1994Q2	7246.931	10327.019	190
1994Q3	7331.075	10387.382	191
1994Q4	7455.288	10506.372	192
1995Q1	7522.289	10543.644	193
1995Q2	7580.997	10575.100	194
1995Q3	7683.125	10665.060	195
1995Q4	7772.586	10737.478	196
1996Q1	7868.468	10817.896	197
1996Q2	8032.840	10998.322	198
1996Q3	8131.408	11096.976	199
1996Q4	8259.771	11212.205	200
1997Q1	8362.655	11284.587	201
1997Q2	8518.825	11472.137	202
1997Q3	8662.823	11615.636	203
1997Q4	8765.907	11715.393	204
1998Q1	8866.480	11832.486	205
1998Q2	8969.699	11942.032	206
1998Q3	9121.097	12091.614	207
1998Q4	9293.991	12287.000	208
1999Q1	9417.264	12403.293	209
1999Q2	9524.152	12498.694	210
1999Q3	9681.856	12662.385	211
1999Q4	9899.378	12877.593	212
2000Q1	10002.857	12924.179	213
2000Q2	10247.679	13160.842	214
2000Q3	10319.825	13178.419	215
2000Q4	10439.025	13260.506	216
2001Q1	10472.879	13222.690	217
2001Q2	10597.822	13299.984	218
2001Q3	10596.294	13244.784	219
2001Q4	10660.294	13280.859	220
2002Q1	10788.952	13397.002	221
2002Q2	10893.207	13478.152	222
2002Q3	10992.051	13538.072	223
2002Q4	11071.463	13559.032	224
2003Q1	11183.507	13634.253	225
2003Q2	11312.875	13751.543	226
2003Q3	11567.326	13985.073	227
2003Q4	11769.275	14145.645	228
2004Q1	11920.169	14221.147	229
2004Q2	12108.987	14329.523	230
2004Q3	12303.340	14464.984	231
2004Q4	12522.425	14609.876	232
2005Q1	12761.337	14771.602	233
2005Q2	12910.022	14839.782	234
2005Q3	13142.873	14972.054	235
2005Q4	13332.316	15066.597	236
2006Q1	13603.933	15267.026	237
2006Q2	13749.806	15302.705	238
2006Q3	13867.469	15326.368	239
2006Q4	14037.228	15456.928	240
2007Q1	14208.569	15493.328	241
2007Q2	14382.363	15582.085	242
2007Q3	14535.003	15666.738	243
2007Q4	14681.501	15761.967	244
2008Q1	14651.039	15671.383	245
2008Q2	14805.611	15752.308	246
2008Q3	14835.187	15667.032	247
2008Q4	14559.543	15328.027	248
2009Q1	14394.547	15155.940	249
2009Q2	14352.850	15134.117	250
2009Q3	14420.312	15189.222	251
2009Q4	14628.021	15356.058	252
2010Q1	14721.350	15415.145	253
2010Q2	14926.098	15557.277	254
2010Q3	15079.917	15671.967	255
2010Q4	15240.843	15750.625	256
2011Q1	15285.828	15712.754	257
2011Q2	15496.189	15825.096	258
2011Q3	15591.850	15820.700	259
2011Q4	15796.460	16004.107	260
2012Q1	16019.758	16129.418	261
2012Q2	16152.257	16198.807	262
2012Q3	16257.151	16220.667	263
2012Q4	16358.863	16239.138	264
2013Q1	16569.591	16382.964	265
2013Q2	16637.926	16403.180	266
2013Q3	16848.748	16531.685	267
2013Q4	17083.137	16663.649	268
2014Q1	17104.555	16616.540	269
2014Q2	17432.909	16841.475	270
2014Q3	17721.657	17047.098	271
2014Q4	17849.912	17143.038	272
2015Q1	17984.178	17277.580	273
2015Q2	18219.405	17405.669	274
2015Q3	18344.713	17463.222	275
2015Q4	18350.825	17468.902	276
2016Q1	18424.283	17556.839	277
2016Q2	18637.253	17639.417	278
2016Q3	18806.743	17735.074	279
2016Q4	18991.883	17824.231	280
2017Q1	19190.431	17925.256	281
2017Q2	19356.649	18021.048	282
2017Q3	19611.704	18163.558	283
2017Q4	19918.910	18322.464	284
2018Q1	20163.159	18438.254	285
2018Q2	20510.177	18598.135	286
2018Q3	20749.752	18732.720	287
2018Q4	20897.804	18783.548	288
2019Q1	21098.827	18927.281	289
2019Q2	21340.267	19021.860	290
2019Q3	21542.540	19121.112	291
2019Q4	21729.124	19221.970	292
2020Q1	21534.907	18974.702	293

141	9.757165	2015
142	9.764551	
143	9.767852	
144	9.768178	
145	9.773199	2016
146	9.777891	
147	9.783300	
148	9.788314	
149	9.793966	2017
150	9.799296	
151	9.807173	
152	9.815883	
153	9.822183	2018
154	9.830817	
155	9.838027	
156	9.840737	
157	9.848360	2019
158	9.853344	
159	9.858548	
160	9.863809	
161	9.850862	2020

CASE: UE 374
WITNESSES: MATT MULDOON-
MOYA ENRIGHT-
CURTIS DLOUHY

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1909
TIPS Implied Inflation Expectations

Exhibits in Support of Rebuttal Testimony

July 24, 2020

Staff Exhibit 1909 is

filed in electronic format

https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

FRB **H.15** Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year

Staff Accessed , July 2, 2020 at: https://www.federalreserve.gov/datadownload/Choose.aspx?rel

Monthly

TIPS-05m	5	**Year**	**Inflation Indexed**	**H.15 ID**	RIFLGFCY**05**_XII_N.**M**
TIPS-07m	7				RIFLGFCY**07**_XII_N.**M**
TIPS-10m	10				RIFLGFCY**10**_XII_N.**M**
TIPS-20m	20				RIFLGFCY**20**_XII_N.**M**
TIPS-30m	30				RIFLGFCY**30**_XII_N.**M**

Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2010-01	0.42	0.85	1.37	2.00	ND
2010-02	0.42	0.90	1.42	2.03	2.16
2010-03	0.56	1.08	1.51	1.98	2.15
2010-04	**0.62**	**1.10**	**1.50**	**1.90**	**2.05**
2010-05	**0.41**	**0.86**	**1.31**	**1.72**	**1.83**
2010-06	**0.34**	**0.76**	**1.26**	**1.69**	**1.77**
2010-07	0.34	0.73	1.24	1.80	1.87
2010-08	0.13	0.51	1.02	1.65	1.76
2010-09	0.13	0.46	0.91	1.58	1.66
2010-10	**-0.32**	**0.02**	**0.53**	**1.32**	**1.44**
2010-11	**-0.21**	**0.17**	**0.67**	**1.44**	**1.61**
2010-12	**0.21**	**0.65**	**1.04**	**1.67**	**1.89**
2011-01	0.06	0.62	1.06	1.70	1.97
2011-02	0.25	0.84	1.24	1.85	2.13
2011-03	-0.09	0.54	0.96	1.58	1.89
2011-04	**-0.14**	**0.49**	**0.86**	**1.48**	**1.79**
2011-05	**-0.34**	**0.29**	**0.78**	**1.47**	**1.77**
2011-06	**-0.38**	**0.21**	**0.76**	**1.53**	**1.78**
2011-07	-0.49	0.09	0.62	1.36	1.62
2011-08	-0.75	-0.36	0.14	0.81	1.10
2011-09	-0.72	-0.39	0.08	0.69	1.02
2011-10	**-0.63**	**-0.28**	**0.19**	**0.72**	**0.99**
2011-11	**-0.85**	**-0.46**	**0.00**	**0.55**	**0.78**
2011-12	**-0.78**	**-0.44**	**-0.03**	**0.56**	**0.78**
2012-01	-0.92	-0.55	-0.11	0.51	0.74
2012-02	-1.11	-0.69	-0.25	0.45	0.72
2012-03	-1.03	-0.57	-0.14	0.56	0.87
2012-04	**-1.06**	**-0.65**	**-0.21**	**0.50**	**0.79**
2012-05	**-1.12**	**-0.79**	**-0.34**	**0.44**	**0.68**
2012-06	**-1.05**	**-0.82**	**-0.50**	**0.10**	**0.50**
2012-07	-1.15	-0.92	-0.60	-0.01	0.39
2012-08	-1.19	-0.94	-0.59	0.06	0.47
2012-09	-1.47	-1.17	-0.71	0.02	0.44
2012-10	**-1.47**	**-1.18**	**-0.75**	**-0.01**	**0.41**
2012-11	**-1.38**	**-1.13**	**-0.77**	**-0.06**	**0.35**
2012-12	**-1.40**	**-1.13**	**-0.76**	**0.00**	**0.33**
2013-01	-1.39	-1.04	-0.61	0.20	0.48
2013-02	-1.39	-0.94	-0.57	0.19	0.57
2013-03	-1.43	-0.97	-0.59	0.19	0.62
2013-04	**-1.38**	**-0.97**	**-0.65**	**0.07**	**0.48**
2013-05	**-1.14**	**-0.69**	**-0.36**	**0.35**	**0.72**
2013-06	**-0.59**	**-0.21**	**0.25**	**0.98**	**1.21**
2013-07	-0.45	0.02	0.46	1.09	1.34
2013-08	-0.33	0.15	0.55	1.16	1.44
2013-09	-0.17	0.34	0.66	1.22	1.50
2013-10	**-0.41**	**0.11**	**0.43**	**1.05**	**1.37**
2013-11	**-0.38**	**0.18**	**0.55**	**1.20**	**1.51**
2013-12	**-0.09**	**0.47**	**0.74**	**1.32**	**1.61**
2014-01	-0.09	0.45	0.63	1.17	1.44
2014-02	-0.26	0.30	0.55	1.12	1.40
2014-03	-0.14	0.37	0.56	1.05	1.33
2014-04	**-0.11**	**0.38**	**0.54**	**0.98**	**1.23**
2014-05	**-0.34**	**0.21**	**0.37**	**0.82**	**1.08**
2014-06	**-0.29**	**0.23**	**0.37**	**0.84**	**1.11**
2014-07	-0.27	0.18	0.28	0.72	0.98
2014-08	-0.21	0.15	0.22	0.64	0.90
2014-09	0.10	0.38	0.46	0.81	1.05
2014-10	**0.06**	**0.32**	**0.38**	**0.74**	**0.96**
2014-11	**0.14**	**0.37**	**0.45**	**0.77**	**0.99**
2014-12	**0.37**	**0.47**	**0.51**	**0.73**	**0.89**
2015-01	0.17	0.24	0.27	0.50	0.66
2015-02	0.11	0.22	0.26	0.52	0.73
2015-03	0.04	0.23	0.28	0.55	0.73
2015-04	**-0.26**	**-0.01**	**0.08**	**0.42**	**0.65**
2015-05	**-0.10**	**0.27**	**0.33**	**0.70**	**0.96**
2015-06	**0.05**	**0.39**	**0.50**	**0.89**	**1.13**
2015-07	0.14	0.42	0.50	0.87	1.11
2015-08	0.31	0.49	0.56	0.87	1.08
2015-09	0.33	0.52	0.65	1.01	1.24
2015-10	**0.21**	**0.39**	**0.57**	**0.98**	**1.22**
2015-11	**0.40**	**0.55**	**0.69**	**1.03**	**1.25**
2015-12	**0.46**	**0.59**	**0.73**	**1.06**	**1.26**
2016-01	0.33	0.49	0.67	1.05	1.26
2016-02	0.14	0.30	0.47	0.85	1.09
2016-03	-0.03	0.16	0.34	0.73	0.99
2016-04	**-0.22**	**-0.03**	**0.19**	**0.60**	**0.86**
2016-05	**-0.22**	**-0.04**	**0.21**	**0.64**	**0.86**
2016-06	**-0.27**	**-0.07**	**0.17**	**0.63**	**0.82**
2016-07	-0.32	-0.16	0.04	0.42	0.61
2016-08	-0.17	-0.06	0.09	0.43	0.62
2016-09	-0.17	-0.05	0.12	0.47	0.64
2016-10	**-0.26**	**-0.10**	**0.10**	**0.49**	**0.69**
2016-11	**-0.07**	**0.11**	**0.32**	**0.69**	**0.86**
2016-12	**0.15**	**0.36**	**0.56**	**0.89**	**1.04**
2017-01	0.03	0.27	0.42	0.74	0.92
2017-02	0.01	0.29	0.40	0.73	0.93
2017-03	0.18	0.42	0.49	0.79	0.99
2017-04	**0.08**	**0.28**	**0.39**	**0.72**	**0.91**
2017-05	**0.09**	**0.29**	**0.47**	**0.80**	**0.99**
2017-06	**0.14**	**0.32**	**0.46**	**0.75**	**0.93**
2017-07	0.23	0.42	0.55	0.84	1.01
2017-08	0.16	0.35	0.43	0.74	0.93
2017-09	0.12	0.31	0.37	0.67	0.87
2017-10	**0.25**	**0.42**	**0.50**	**0.77**	**0.94**
2017-11	**0.30**	**0.43**	**0.50**	**0.72**	**0.87**
2017-12	**0.42**	**0.48**	**0.50**	**0.68**	**0.80**
2018-01	0.45	0.51	0.54	0.69	0.80
2018-02	0.63	0.73	0.76	0.89	0.99
2018-03	0.61	0.71	0.75	0.89	0.99
2018-04	**0.65**	**0.72**	**0.74**	**0.85**	**0.93**
2018-05	**0.72**	**0.82**	**0.84**	**0.92**	**0.98**
2018-06	**0.71**	**0.76**	**0.79**	**0.87**	**0.93**
2018-07	0.74	0.76	0.77	0.84	0.88
2018-08	0.79	0.79	0.79	0.86	0.92
2018-09	0.89	0.88	0.88	0.95	1.00
2018-10	**1.01**	**1.03**	**1.04**	**1.14**	**1.21**
2018-11	**1.10**	**1.11**	**1.11**	**1.21**	**1.30**
2018-12	**1.08**	**1.04**	**1.02**	**1.11**	**1.19**
2019-01	0.91	0.91	0.92	1.07	1.19
2019-02	0.73	0.76	0.80	0.96	1.10
2019-03	0.56	0.60	0.66	0.85	1.02
2019-04	**0.49**	**0.54**	**0.60**	**0.79**	**0.97**
2019-05	**0.48**	**0.52**	**0.57**	**0.75**	**0.92**
2019-06	**0.28**	**0.32**	**0.37**	**0.59**	**0.79**
2019-07	0.25	0.27	0.31	0.54	0.77
2019-08	0.11	0.07	0.04	0.25	0.49
2019-09	0.17	0.13	0.11	0.32	0.51
2019-10	**0.12**	**0.12**	**0.15**	**0.36**	**0.55**
2019-11	**0.09**	**0.12**	**0.17**	**0.37**	**0.54**
2019-12	**0.06**	**0.09**	**0.14**	**0.35**	**0.52**
2020-01	-0.09	-0.04	0.04	0.26	0.43
2020-02	-0.26	-0.20	-0.11	0.12	0.29
2020-03	-0.08	-0.13	-0.12	0.03	0.16
2020-04	**-0.37**	**-0.44**	**-0.45**	**-0.28**	**-0.12**
2020-05	**-0.43**	**-0.45**	**-0.44**	**-0.26**	**-0.08**
2020-06	**-0.67**	**-0.62**	**-0.54**	**-0.28**	**-0.06**

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Monthly

UST-05m	5	**Year**	**H.15 ID**	RIFLGFCY**05**_N.**M**
UST-07m	7			RIFLGFCY**07**_N.**M**
UST-10m	10			RIFLGFCY**10**_N.**M**
UST-20m	20			RIFLGFCY**20**_N.**M**
UST-30m	30			RIFLGFCY**30**_N.**M**

Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2010-01	2.48	3.21	3.73	4.50	4.60
2010-02	2.36	3.12	3.69	4.48	4.62
2010-03	2.43	3.16	3.73	4.49	4.64
2010-04	**2.58**	**3.28**	**3.85**	**4.53**	**4.69**
2010-05	**2.18**	**2.86**	**3.42**	**4.11**	**4.29**
2010-06	**2.00**	**2.66**	**3.20**	**3.95**	**4.13**
2010-07	1.76	2.43	3.01	3.80	3.99
2010-08	1.47	2.10	2.70	3.52	3.80
2010-09	1.41	2.05	2.65	3.47	3.77
2010-10	**1.18**	**1.85**	**2.54**	**3.52**	**3.87**
2010-11	**1.35**	**2.02**	**2.76**	**3.82**	**4.19**
2010-12	**1.93**	**2.66**	**3.29**	**4.17**	**4.42**
2011-01	1.99	2.72	3.39	4.28	4.52
2011-02	2.26	2.96	3.58	4.42	4.65
2011-03	2.11	2.80	3.41	4.27	4.51
2011-04	**2.17**	**2.84**	**3.46**	**4.28**	**4.50**
2011-05	**1.84**	**2.51**	**3.17**	**4.01**	**4.29**
2011-06	**1.58**	**2.29**	**3.00**	**3.91**	**4.23**
2011-07	1.54	2.28	3.00	3.95	4.27
2011-08	1.02	1.63	2.30	3.24	3.65
2011-09	0.90	1.42	1.98	2.83	3.18
2011-10	**1.06**	**1.62**	**2.15**	**2.87**	**3.13**
2011-11	**0.91**	**1.45**	**2.01**	**2.72**	**3.02**
2011-12	**0.89**	**1.43**	**1.98**	**2.67**	**2.98**
2012-01	0.84	1.38	1.97	2.70	3.03
2012-02	0.83	1.37	1.97	2.75	3.11
2012-03	1.02	1.56	2.17	2.94	3.28
2012-04	**0.89**	**1.43**	**2.05**	**2.82**	**3.18**
2012-05	**0.76**	**1.21**	**1.80**	**2.53**	**2.93**
2012-06	**0.71**	**1.08**	**1.62**	**2.31**	**2.70**
2012-07	0.62	0.98	1.53	2.22	2.59
2012-08	0.71	1.14	1.68	2.40	2.77
2012-09	0.67	1.12	1.72	2.49	2.88
2012-10	**0.71**	**1.15**	**1.75**	**2.51**	**2.90**
2012-11	**0.67**	**1.08**	**1.65**	**2.39**	**2.80**
2012-12	**0.70**	**1.13**	**1.72**	**2.47**	**2.88**
2013-01	0.81	1.30	1.91	2.68	3.08
2013-02	0.85	1.35	1.98	2.78	3.17
2013-03	0.82	1.32	1.96	2.78	3.16
2013-04	**0.71**	**1.15**	**1.76**	**2.55**	**2.93**
2013-05	**0.84**	**1.31**	**1.93**	**2.73**	**3.11**
2013-06	**1.20**	**1.71**	**2.30**	**3.07**	**3.40**
2013-07	1.40	1.99	2.58	3.31	3.61
2013-08	1.52	2.15	2.74	3.49	3.76
2013-09	1.60	2.22	2.81	3.53	3.79
2013-10	**1.37**	**1.99**	**2.62**	**3.38**	**3.68**
2013-11	**1.37**	**2.07**	**2.72**	**3.50**	**3.80**
2013-12	**1.58**	**2.29**	**2.90**	**3.63**	**3.89**
2014-01	1.65	2.29	2.86	3.52	3.77
2014-02	1.52	2.15	2.71	3.38	3.66
2014-03	1.64	2.23	2.72	3.35	3.62
2014-04	**1.70**	**2.27**	**2.71**	**3.27**	**3.52**
2014-05	**1.59**	**2.12**	**2.56**	**3.12**	**3.39**
2014-06	**1.68**	**2.19**	**2.60**	**3.15**	**3.42**
2014-07	1.70	2.17	2.54	3.07	3.33
2014-08	1.63	2.08	2.42	2.94	3.20
2014-09	1.77	2.22	2.53	3.01	3.26
2014-10	**1.55**	**1.98**	**2.30**	**2.77**	**3.04**
2014-11	**1.62**	**2.03**	**2.33**	**2.76**	**3.04**
2014-12	**1.64**	**1.98**	**2.21**	**2.55**	**2.83**
2015-01	1.37	1.67	1.88	2.20	2.46
2015-02	1.47	1.79	1.98	2.34	2.57
2015-03	1.52	1.84	2.04	2.41	2.63
2015-04	**1.35**	**1.69**	**1.94**	**2.33**	**2.59**
2015-05	**1.54**	**1.93**	**2.20**	**2.69**	**2.96**
2015-06	**1.68**	**2.10**	**2.36**	**2.85**	**3.11**
2015-07	1.63	2.04	2.32	2.77	3.07
2015-08	1.54	1.91	2.17	2.55	2.86
2015-09	1.49	1.88	2.17	2.62	2.95
2015-10	**1.39**	**1.76**	**2.07**	**2.50**	**2.89**
2015-11	**1.67**	**2.02**	**2.26**	**2.69**	**3.03**
2015-12	**1.70**	**2.04**	**2.24**	**2.61**	**2.97**
2016-01	1.52	1.85	2.09	2.49	2.86
2016-02	1.22	1.53	1.78	2.20	2.62
2016-03	1.38	1.68	1.89	2.28	2.68
2016-04	**1.26**	**1.57**	**1.81**	**2.21**	**2.62**
2016-05	**1.30**	**1.60**	**1.81**	**2.22**	**2.63**
2016-06	**1.17**	**1.44**	**1.64**	**2.02**	**2.45**
2016-07	1.07	1.33	1.50	1.82	2.23
2016-08	1.13	1.40	1.56	1.89	2.26
2016-09	1.18	1.46	1.63	2.02	2.35
2016-10	**1.27**	**1.56**	**1.76**	**2.17**	**2.50**
2016-11	**1.60**	**1.93**	**2.14**	**2.54**	**2.86**
2016-12	**1.96**	**2.29**	**2.49**	**2.84**	**3.11**
2017-01	1.92	2.23	2.43	2.75	3.02
2017-02	1.90	2.22	2.42	2.76	3.03
2017-03	2.01	2.30	2.48	2.83	3.08
2017-04	**1.82**	**2.10**	**2.30**	**2.67**	**2.94**
2017-05	**1.84**	**2.11**	**2.30**	**2.70**	**2.96**
2017-06	**1.77**	**2.01**	**2.19**	**2.54**	**2.80**
2017-07	1.87	2.13	2.32	2.65	2.88
2017-08	1.78	2.03	2.21	2.55	2.80
2017-09	1.80	2.03	2.20	2.53	2.78
2017-10	**1.98**	**2.20**	**2.36**	**2.65**	**2.88**
2017-11	**2.05**	**2.23**	**2.35**	**2.60**	**2.80**
2017-12	**2.18**	**2.32**	**2.40**	**2.60**	**2.77**
2018-01	2.38	2.51	2.58	2.73	2.88
2018-02	2.60	2.78	2.86	3.02	3.13
2018-03	2.63	2.77	2.84	2.97	3.09
2018-04	**2.70**	**2.82**	**2.87**	**2.96**	**3.07**
2018-05	**2.82**	**2.93**	**2.98**	**3.05**	**3.13**
2018-06	**2.78**	**2.87**	**2.91**	**2.98**	**3.05**
2018-07	2.78	2.85	2.89	2.94	3.01
2018-08	2.77	2.84	2.89	2.97	3.04
2018-09	2.89	2.96	3.00	3.08	3.15
2018-10	**3.00**	**3.09**	**3.15**	**3.27**	**3.34**
2018-11	**2.95**	**3.04**	**3.12**	**3.27**	**3.36**
2018-12	**2.68**	**2.75**	**2.83**	**2.98**	**3.10**
2019-01	2.54	2.61	2.71	2.89	3.04
2019-02	2.49	2.57	2.68	2.87	3.02
2019-03	2.37	2.47	2.57	2.80	2.98
2019-04	**2.33**	**2.43**	**2.53**	**2.76**	**2.94**
2019-05	**2.19**	**2.29**	**2.40**	**2.63**	**2.82**
2019-06	**1.83**	**1.95**	**2.07**	**2.36**	**2.57**
2019-07	1.83	1.93	2.06	2.36	2.57
2019-08	1.49	1.55	1.63	1.91	2.12
2019-09	1.57	1.64	1.70	1.97	2.16
2019-10	**1.53**	**1.62**	**1.71**	**2.00**	**2.19**
2019-11	**1.64**	**1.74**	**1.81**	**2.13**	**2.28**
2019-12	**1.68**	**1.79**	**1.86**	**2.16**	**2.30**
2020-01	1.56	1.67	1.76	2.07	2.22
2020-02	1.32	1.42	1.50	1.81	1.97
2020-03	0.59	0.78	0.87	1.26	1.46
2020-04	**0.39**	**0.55**	**0.66**	**1.06**	**1.27**
2020-05	**0.34**	**0.53**	**0.67**	**1.12**	**1.38**
2020-06	**0.34**	**0.55**	**0.73**	**1.27**	**1.49**

Annual

TIPS-05a	5	**Year**	**Inflation Indexed**	**H.15 ID**	RIFLGFCY**05**_XII_N.**A**
TIPS-07a	7				RIFLGFCY**07**_XII_N.**A**
TIPS-10a	10				RIFLGFCY**10**_XII_N.**A**
TIPS-20a	20				RIFLGFCY**20**_XII_N.**A**
TIPS-30a	30				RIFLGFCY**30**_XII_N.**A**

Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a
2010	0.26	0.68	1.15	1.73	1.82
2011	-0.41	0.09	0.55	1.19	1.47
2012	-1.19	-0.87	-0.48	0.22	0.56
2013	0.76	-0.29	0.07	0.75	1.07
2014	-0.09	0.32	0.44	0.86	1.11
2015	0.15	0.36	0.45	0.78	1.00
2016	-0.01	0.07	0.27	0.65	0.86
2017	0.17	0.36	0.46	0.75	0.92
2018	0.78	0.82	0.83	0.93	1.01
2019	**0.35**	**0.37**	**0.40**	**0.60**	**0.78**

Annual

UST-05a	5	**Year**	**H.15 ID**	RIFLGFCY**05**_N.**A**
UST-07a	7			RIFLGFCY**07**_N.**A**
UST-10a	10			RIFLGFCY**10**_N.**A**
UST-20a	20			RIFLGFCY**20**_N.**A**
UST-30a	30			RIFLGFCY**30**_N.**A**

Year	UST-05a	UST-07a	UST-10a	UST-20a	UST-30a
2010	1.93	2.62	3.22	4.03	4.25
2011	1.52	2.16	2.78	3.62	3.91
2012	0.76	1.22	1.80	2.54	2.92
2013	1.17	1.74	2.35	3.12	3.45
2014	1.64	2.14	2.54	3.07	3.34
2015	1.53	1.89	2.14	2.55	2.84
2016	1.33	1.63	1.84	2.22	2.59
2017	1.91	2.16	2.33	2.65	2.89
2018	2.75	2.85	2.91	3.02	3.11
2019	**1.96**	**2.05**	**2.14**	**2.40**	**2.58**

Notes:

ND: No Data available

CASE: UE 374
WITNESSES: MATT MULDOON-
MOYA ENRIGHT-
CURTIS DLOUHY

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1910
Value Line (VL) Updated Review of U.S. Electric Utilities

Exhibits in Support of Rebuttal Testimony

July 24, 2020

All of the major electric utilities located in the eastern region of the United States are reviewed in this Issue; western electrics, in Issue 11; and the remaining utilities, in Issue 5.

As companies' first-quarter results are being released and conference calls with analysts are being conducted, we discuss how the Electric Utility Industry is responding to the coronavirus-related problems.

Regulatory mechanisms that decouple revenues and volume are proving to be a boon for those utilities that operate under such mechanisms.

As a group, electric utility stocks have declined in price far less than the broader market average since the market turmoil began in late February. However, they have not been immune to the market's volatility.

The Industry's Coronavirus Response

When companies in the Electric Utility Industry reported earnings (in February, in most cases) for the fourth quarter of 2019, the subject of coronavirus rarely came up, and then just in passing when it did. This changed considerably when companies reported results for the first period of 2020. (When this report went to press in early May, about half of the companies in this Industry had still not reported March-quarter earnings.) The lockdowns and forced business closings that most states imposed did not begin until mid- to late March, so there was little effect on kilowatt-hour sales in the first quarter. Volume declines that some companies reported occurred mainly from a milder-than-normal winter in many parts of the United States. *Public Service Enterprise Group* has cut costs in response to the fall in kilowatt-hour sales. Note that increased sales to residential customers (the most profitable, typically) will offset part of the decline in volume to commercial and industrial users.

Utilities have had to change the way they operate in the current situation. For instance, if personnel must be reduced for certain jobs, this can lead to additional overtime pay. Cleaning and disinfecting things has a cost, too. (At this point, companies have not reported any problems in their ability to obtain equipment.) Most utilities have announced charitable contributions to organizations that address problems caused by the coronavirus, an expense paid by shareholders, not customers. Because utilities are not disconnecting customers for nonpayment (and, in most cases, are suspending late fees), this will result in higher bad-debt expense. Some regulatory commissions, such as the one in Maryland, have directed utilities to track their coronavirus-related costs for future recovery. This will help *FirstEnergy* and *Exelon*, which operate in the state. Some utilities will likely postpone rate cases due to the weak economy, too. *Duke Energy* has already had a delay in a regulatory proceeding. Unfortunately, *Consolidated Edison*, operating in New York City and environs, has lost a number of employees to the virus.

Upon reporting first-quarter results, some companies maintained their 2020 earnings guidance, while others cut it. *NextEra Energy*, *Public Service Enterprise Group*,

INDUSTRY TIMELINESS: 30 (of 95)

and *AVANGRID* are among the companies that reiterated their targeted earnings ranges. The board of directors of *Southern Company* raised the dividend in the second quarter, as usual, despite the difficulties caused by the pandemic. On the other hand, Portland General Electric (covered in Issue 11) cut its profit guidance, and its board did not increase the disbursement at its April meeting, in contrast to the practice in recent years. NorthWestern (reviewed in Issue 11) also reduced its earnings target.

Revenue Decoupling

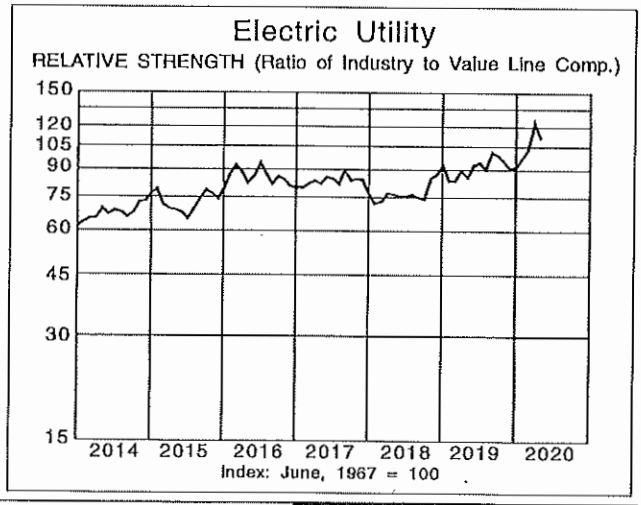
Historically, electric companies' revenues rose or fell along with changes in volume. This makes utilities' earnings susceptible to fluctuations in sales caused by the weather or changes in the state of the economy. It also provides a disincentive for companies to promote energy-efficiency measures (although most utilities do so anyway).

In recent years, an increasing number of utilities have been operating under regulatory mechanisms that decouple revenues from electric and/or gas volume. Under these mechanisms, revenues advance through increases in the customer count or in the rate base, instead of rises in sales of electricity or natural gas. *Consolidated Edison*, *Eversource Energy*, and *AVANGRID* are among the utilities for which most of their revenues are not based on volume. These utilities' earnings are likely to hold up well, even as the economic turmoil causes sales to decline. Some companies are asking for decoupling mechanisms in current rate proceedings, and we believe the current economic problems will spur more utilities to follow suit.

Conclusion

Utility stocks are seen as a safe (more accurately, less-risky) haven when the markets are turbulent. Most of the equities in this group have declined far less than the broader market averages since the market plummeted in late February. However, the volatility these issues have exhibited has belied their high Price Stability Indexes. The quotations of most stocks in the Electric Utility Industry have fallen between 10% and 20% so far this year. The average dividend yield for this group is 3.8%.

Paul E. Debbas, CFA



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All of the major electric utilities located in the central region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 11.

By mid-May, every company in the Electric Utility Industry had reported earnings for the first quarter of 2020. There has been a variance of responses to earnings guidance. We discuss dividends, as well.

Electric utility stocks, as a group, have outperformed the broader market averages in 2020. There has been a wider-than-usual disparity in the performances of individual stocks. Electric company equities have exhibited more volatility than usual, too.

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Earnings Guidance For 2020

By mid-May, all 37 companies in the Electric Utility Industry had reported earnings for the first quarter of 2020. Most companies held conference calls with analysts discussing their results, how they are responding to the coronavirus pandemic and the poor state of the economy, and earnings prospects for the full year. A few utilities also provided data about their kilowatt-hour sales since the end of the March period. Note that two companies reviewed in this Issue, *Fortis* and *MGE Energy*, do not provide earnings guidance, and *Evergy* is not doing so while a strategic review of the company is pending.

Utilities had contingency plans in place stating how to deal with a pandemic, and there haven't been any reports of serious operating problems. However, utilities have incurred expenses associated with the coronavirus and the weak economy. Due to the effects of the steep economic downturn, utilities have suspended disconnections for nonpayment and waived late fees. Some, such as Oklahoma Gas and Electric (the utility subsidiary of *OGE Energy*) also accelerated the timing of the pass-through to customers of lower fuel costs. Companies have also incurred costs related to the situation, such as bad-debt expense, changes in work practices, protective equipment, and additional cleaning of workplaces. Some states already allowed utilities to defer for future recovery excess bad-debt costs. Wisconsin was one of the first states to allow all utilities to defer coronavirus-related expenses. This benefits *Wisconsin Energy*, *Alliant Energy*, and *MGE Energy*. Several other states have followed suit.

Most states issued stay-at-home orders and ordered "nonessential" businesses to close. As more workers worked from home and students studied from home, that caused residential kilowatt-hour sales to increase. However, steep declines in commercial and industrial volume outweighed the gains from residential users. Because of this unique situation, some utilities provided sales data for April, which is atypical. For instance, Madison Gas and Electric, the utility subsidiary of *MGE Energy*, reported that retail kilowatt-hour sales fell 8.7% in April. As governments in many states began to loosen their restrictions in May, that helped volume recover. Still, the effects of the weak economy will rednce utility income for electric companies. As a result, utility management has instituted cost-cutting programs.

Utilities have had varied responses when providing earnings guidance with their first-quarter earnings releases and conference calls. *DTE Energy*, *WEC Energy*, *Ameren*, *CMS Energy*, and *Alliant Energy* did not change their targets. *American Electric Power* did not adjust its guidance either, but indicated that its most likely outcome is in the lower half of its range. *Otter Tail Corporation*, which owns some nonutility businesses, lowered its guidance due to the effects of the recession on its manufacturing business. *OGE Energy* also cut its target due to a decline in equity income from its stake in Enable Midstream Partners, a natural gas master limited partnership. (*CenterPoint Energy* also has a stake in Enable.) *ALLETE* withdrew its expectation due to the heightened uncertainty, but might reinstate guidance upon reporting second-quarter results (most likely in early August).

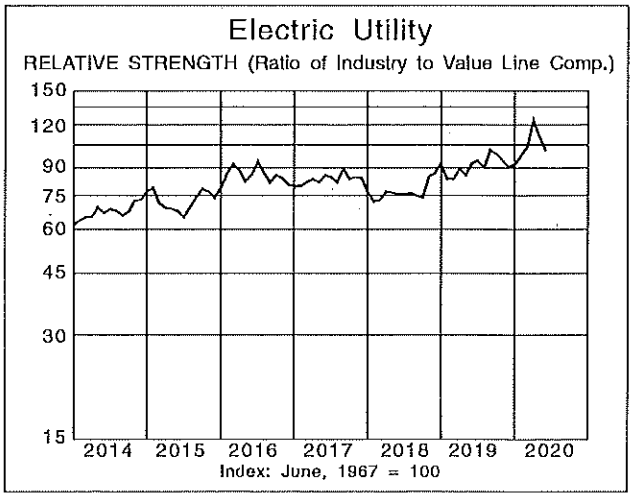
What About Dividends?

The board of directors of *CenterPoint Energy* slashed its dividend 48%, largely due to a steep decline in the value of its investment in, and a cut in the distributions received from, Enable. The boards of *ALLETE*, *Alliant Energy*, *WEC Energy*, and *Otter Tail* raised the payont in January or February, before the economic problems began. *DTE Energy* reiterated its expectation of 7% increases this year and next. Perhaps the economic problems will result in a lower rate of dividend growth, but we do not expect the boards of any companies reviewed here to cut the disbursement.

Conclusion

The price of almost every electric utility stock has declined in 2020, steeply in some cases. Most notably, the quotation of *CenterPoint Energy* has plummeted 34%. By contrast, the prices of *Ameren*, *Evergy*, *Fortis*, and *WEC Energy* have risen or declined just slightly, as these companies are pure plays in the regulated utility business and are better positioned to cope with the problems brought on by the economic downturn. The average dividend yield of equities in the Electric Utility Industry is 3.6%. Several issues reviewed this week offer attractive 18-month total return potential, but prospects for the period to 2023-2025 aren't as appealing.

Paul E. Debbas, CFA



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All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

We discuss the potential effects of the coronavirus problem on the Electric Utility Industry.

We discuss the effects of low oil and gas prices on the Electric Utility Industry.

The prices of most stocks in the Electric Utility Industry have plummeted since late February, but not as much as the overall market.

The Coronavirus Problem

Unlike some industries (e.g., airlines, cruise ships, hotels, restaurants), there are few direct effects of the coronavirus scare on electric utilities. Most companies already have the parts and equipment they need for their 2020 capital spending plans, and there are no restrictions on what they must do to keep the lights on. As for electric and gas volume (many electric companies also distribute natural gas), there is no doubt that the severe shutdowns of much of the economy will hurt commercial and industrial sales. However, with more people staying at home for more hours every day, this is bound to raise residential sales, which have higher margins than commercial or industrial volume. What the net effect on utilities' profits will be remains to be seen. *PNM Resources* has stated that it should still be able to meet its earnings guidance assuming the economic shutdowns last tbrough May, but not if these last well beyond May. Note that some companies, such as the utility subsidiaries of *Edison International*, *Sempra Energy*, and *Hawaiian Electric Industries*, operate under regulatory schemes that decouple revenues and volume. Thus, even if kilowatt-hour sales decline due to the disruption in the economy, this will not have an immediate effect on profitability. Even so, to the extent that these companies' revenues are based on customer growth or rate-base growth, the current turmoil might well have a negative effect in the long run.

What other effects might there be? Most utilities are suspending disconnections for nonpayment during the crisis, either voluntarily or by law, so their bad-debt expense will increase. Many are also waiving late fees. The disruption to normal operations might delay regulatory proceedings, and the economic downturn might dissuade utilities from filing rate cases. On the other hand, companies will save money in certain areas, such as executive travel, which has been curtailed. At least access to capital does not appear to be a problem. But many utilities are tapping their credit lines, just in case.

The Effects Of Low Gas And Oil Prices

Since the coronavirus crisis began, gas and oil prices have declined from levels that were already low. Contrary to what some believe, electric utilities do not use much oil to generate power. (The three utility subsidiaries of *Hawaiian Electric Industries* are the exceptions.) Most electric companies do use natural gas to generate electricity, and (as mentioned above) many have gas distribution operations. In this Issue, the companies

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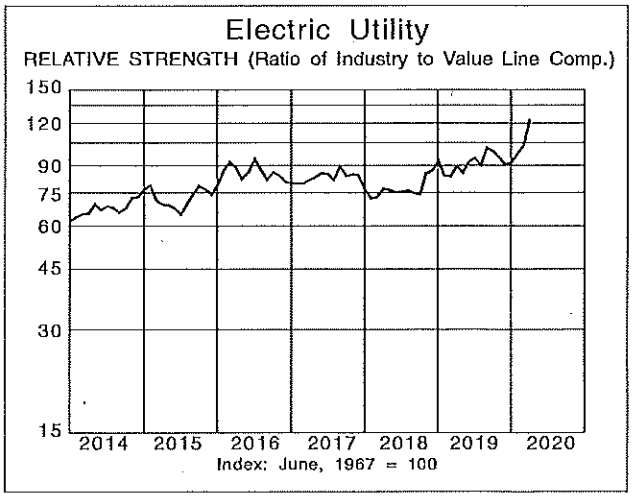
with gas distribution include *Avista*, *Black Hills*, *NorthWestern*, *Sempra*, and *Xcel Energy*. Even though lower gas prices are passed through to customers, this is good for utilities because this makes bills more affordable. It also makes obtaining rate relief less difficult because the decline in gas prices offsets some of the increase in base tariffs. Note that revenues for some utilities might well decline because of lower gas prices. This is an example of why investors should not pay undue attention to utilities' top lines.

Some companies in the Electric Utility Industry are hurt by low commodity prices. CenterPoint Energy and OGE Energy (each covered in Issue 5) have stakes in Enable Midstream Partners (reviewed in Issue 3), a midstream gas master limited partnership. The price of Enable stock has plummeted due to concern about the effects of low commodity prices on production, and this is reflected in the quotations for CenterPoint and OGE. DTE Energy, also covered in Issue 5, has seen its stock price decline because the company has midstream gas assets. *Sempra Energy*, involved in liquefied natural gas, has been affected, as well.

Conclusion

Utilities are usually seen as a safe haven when the markets are in turmoil. Most of these stocks have declined far less than the broader market averages, but have been much more volatile than their high Price Stability Indexes suggest. Even a Safety rank of 1 (Highest) does not necessarily mean that a sharp decline cannot occur. Additionally, there has been a wide variance in the performance of these equities. The stock of *Xcel Energy* has advanced modestly in price this year, but the stock of *Edison International* has fallen more than 20% in price. The average dividend yield of stocks in this industry has risen to 3.55% after having fallen below 3% before the market tumbled in late February. Because the broader market has declined far more than the Electric Utility Industry, the median yield of dividend-paying stocks in *The Value Line Investment Survey* is not considerably lower than the median of the equities in this group.

Paul E. Debbas, CFA



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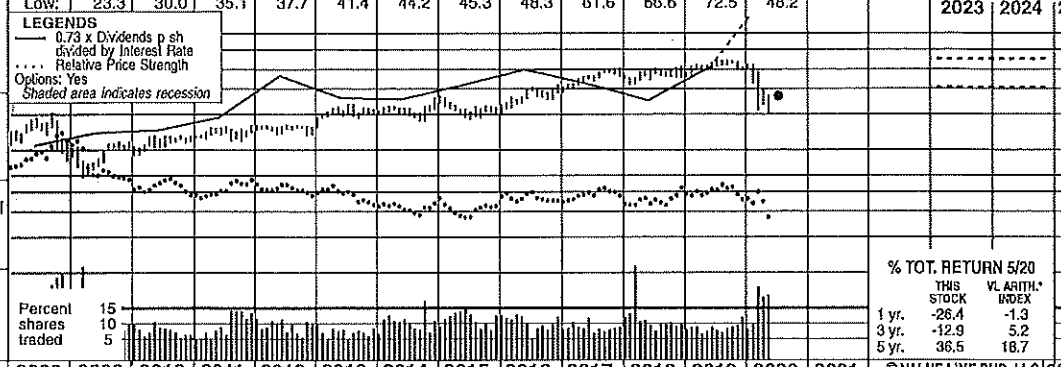
ALLETE NYSE-ALE

RECENT PRICE 59.20 | P/E RATIO 19.4 (Trailing: 17.2 Median: 18.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Lowered 4/5/19
SAFETY 2 New 10/10/04
TECHNICAL 3 Raised 5/1/20
BETA .85 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
High:	35.3	37.9	42.5	42.7	54.1	58.0	59.7	66.9	81.2	82.8	88.6	84.7
Low:	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6	72.5	48.2

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$49-$106	$78 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+50%)	14%
Low	65	(+10%)	7%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	125	158	124
to Sell	142	120	154
Hld's(000)	38347	38235	38410

Percent shares traded 15 10 5

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-26.4	-1.3
3 yr.	-12.9	5.2
5 yr.	36.5	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	29.10	23.99	*22.00*	*23.25*	Revenues per sh	*25.75*
2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	7.37	7.24	*7.05*	*7.65*	"Cash Flow" per sh	*9.00*
1.35	2.48	2.77	3.08	2.62	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	3.38	3.33	*3.05*	*3.50*	Earnings per sh A	*4.25*
.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	2.24	2.35	*2.47*	*2.58*	Div'd Decl'd per sh B ■ †	*2.90*
2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	6.07	11.55	*14.80*	*11.20*	Cap'l Spending per sh	*3.25*
21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	41.86	43.17	*46.30*	*47.65*	Book Value per sh C	*51.75*
29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	51.50	51.70	*52.75*	*53.50*	Common Shs Outst'g D	*54.25*
25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	22.2	24.7	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.16	1.20	1.32	*Value Line*		Relative P/E Ratio	*1.05*
.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%	3.0%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $1722.9 mill. Due in 5 Yrs $562.6 mill.
LT Debt $1399.9 mill. LT Interest $61.1 mill.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $6.6 mill.

Pension Assets-12/19 $699.6 mill. Oblig $854.0 mill.

Pfd Stock None

Common Stock 51,787,412 shs.

MARKET CAP: $3.1 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
907.0	926.2	961.2	1018.4	1136.8	1486.4	1339.7	1419.3	1498.6	1240.5	*1160*	*1245*	Revenues ($mill)	*1450*
75.3	93.8	97.1	104.7	124.8	163.4	155.3	159.2	174.1	172.4	*160*	*185*	Net Profit ($mill)	*230*
37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	14.8%	NMF	*NMF*	*Nil*	Income Tax Rate	*Nil*
8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	1.4%	.8%	.7%	1.3%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
44.2%	44.3%	43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	39.9%	38.6%	*41.0%*	*40.0%*	Long-Term Debt Ratio	*41.0%*
55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	*59.0%*	*60.0%*	Common Equity Ratio	*59.0%*
1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	3584.3	3632.8	*4140*	*4250*	Total Capital ($mill)	*4750*
1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	3904.4	4377.0	*4945*	*5320*	Net Plant ($mill)	*5575*
5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	5.8%	5.6%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	*6.5%*	*7.5%*	Return on Shr. Equity	*8.0%*
7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	*6.5%*	*7.5%*	Return on Com Equity E	*8.0%*
1.5%	2.9%	2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	2.7%	2.3%	*1.5%*	*2.0%*	Retained to Com Eq	*2.5%*
81%	66%	71%	72%	67%	60%	66%	68%	66%	70%	*81%*	*74%*	All Div'ds to Net Prof	*69%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+8.4	-.2	-1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	1599	1589	1573
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	339	296	277

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	1.0%	2.0%	*-1.0%*
"Cash Flow"	5.5%	6.0%	*4.0%*
Earnings	2.5%	4.0%	*5.5%*
Dividends	3.0%	3.5%	*4.5%*
Book Value	5.0%	5.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2017	365.6	353.3	362.5	337.9	1419.3
2018	358.2	344.1	348.0	448.3	1498.6
2019	357.2	290.4	288.3	304.6	1240.5
2020	311.6	*280*	*280*	*288.4*	*1160*
2021	*330*	*300*	*300*	*315*	*1245*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2017	.97	.72	.88	.56	3.13
2018	.99	.61	.59	1.18	3.38
2019	1.18	.64	.60	.92	3.33
2020	1.28	*.50*	*.52*	*.75*	*3.05*
2021	*1.20*	*.70*	*.65*	*.95*	*3.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.52	.52	.52	.52	2.08
2017	.535	.535	.535	.535	2.14
2018	.56	.56	.56	.56	2.24
2019	.5875	.5875	.5875	.5875	2.35
2020	.6175	.6175			

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 16% other, 16%. ALLETE Clean Energy (ACE) owns renewable energy projects. Acq'd U.S. Water Services 2/15; sold it 3/19. Generating sources: coal & lignite, 30%; wind, 11%; other, 5%; purchased, 54%. Fuel costs: 31% of revs. '19 deprec. rate: 3.3%. Has 1,400 employees. Chairman: Alan R. Hodnik. President & CEO: Bethany M. Owen. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's main utility subsidiary had its interim rate increase reduced. Last November, Minnesota Power filed for a $65.9 million (10.6%) rate increase, based on a return on equity of 10.05% and a common-equity ratio of 53.81%. At the start of 2020, Minnesota Power received an interim hike of $36.1 million (5.8%). The interim hike was reduced to $25.5 million (4.1%), and the effective date postponed to May 1st, in response to the economic problems caused by the coronavirus situation. This will result in a $12 million revenue refund to customers. The utility also withdrew its rate application and will not refile a case before November 1, 2021. It may file as early as March 1st under certain conditions, such as a 50-megawatt loss of load for three months.

We lowered our 2020 and 2021 earnings estimates. The revenue refund will result in a charge of $0.16 a share against second-quarter results, and having a lower interim rate hike will affect the company's earning power until Minnesota Power files its next rate case. In addition, revenues from large industrial customers will probably be lower in the last four months of 2020. (For now, there is no revenue impact because these customers put forth full power-demand nominations, before the economy worsened, through the end of August.) Putting it all together, we cut our 2020 share-net estimate by $0.50, to $3.05, and our 2021 expectation by $0.30, to $3.50. Due to the problems and increased uncertainty caused by the coronavirus, ALLETE has withdrawn its earnings guidance. Management hopes to update guidance with its second-quarter release.

ALLETE Clean Energy is faring well. Its wind projects are on track, and the coronavirus has not disrupted construction. Most significantly, a 300-megawatt project is scheduled for completion by yearend at an expected cost of $450 million.

This has been one of the poorest-performing stocks in this industry in 2020. The price is down 27% in this time frame. Minnesota Power's service area has a much-larger industrial sector than most utilities, which worries investors. The dividend yield is above the industry average, and total return potential for the 18-month period is strong.

Paul E. Debbas, CFA *June 12, 2020*

(A) Diluted EPS. Excl. nonrec. gains (losses): '04, (25¢); '05, ($1.84); '15, (46¢); '17, 25¢; '19, 26¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '18 & '19 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred charges. In '19: $8.15/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '19: 7.9%. Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	80

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ALLIANT ENERGY NDQ-LNT

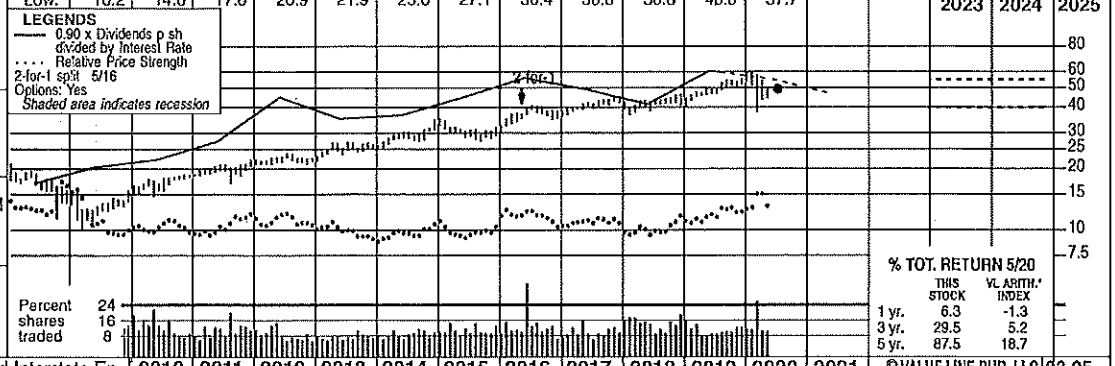
RECENT PRICE 49.46 | P/E RATIO 20.2 (Trailing: 19.6 Median: 17.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 2 Lowered 5/29/20
SAFETY 2 Raised 9/28/07
TECHNICAL 2 Lowered 6/12/20
BETA .80 (1.00 = Market)

High:	15.8	18.8	22.2	23.8	27.1	34.9	35.4	41.0	45.6	46.6	55.4	60.3
Low:	10.2	14.6	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8	40.8	37.7

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/16
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$38-$83	$61 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+10%)	6%
Low	40	(-20%)	-1%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	248	272	236
to Sell	233	209	272
Hld's(000)	185069	188011	182284

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.3	-1.3
3 yr.	29.5	5.2
5 yr.	87.5	18.7

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	14.89	*14.70*	*15.10*	Revenues per sh	*15.85*
2.60	2.75	2.95	3.34	3.44	3.45	3.45	3.10	4.32	4.59	*4.75*	*4.90*	"Cash Flow" per sh	*5.25*
1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	2.33	*2.45*	*2.55*	Earnings per sh A	*3.00*
.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	1.42	*1.52*	*1.64*	Div'd Decl'd per sh B ■ †	*2.00*
3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.34	6.28	*5.65*	*5.90*	Cap'l Spending per sh	*6.15*
13.05	13.57	14.12	14.79	15.54	16.41	16.96	17.21	19.43	21.24	*22.75*	*24.10*	Book Value per sh C	*28.25*
221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	245.02	*250.00*	*255.00*	Common Shs Outst'g D	*265.00*
12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	21.2	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.60	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.19	*Value Line*		Relative P/E Ratio	*.90*
4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
3416.1	3665.3	3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	*3675*	*3850*	Revenues ($mill)	*4205*
303.9	304.4	337.8	382.1	385.5	380.7	373.8	455.9	512.1	557.2	*610*	*630*	Net Profit ($mill)	*790*
30.1%	19.0%	21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	*NMF*	*11.0%*	Income Tax Rate	*11.0%*
--	--	--	--	--	6.5%	7.0%	7.6%	7.8%	7.6%	*7.5%*	*7.5%*	AFUDC % to Net Profit	*7.5%*
46.3%	45.7%	48.4%	46.1%	49.7%	48.6%	52.8%	49.0%	53.4%	51.5%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*52.0%*
49.5%	50.9%	48.4%	50.8%	47.5%	51.4%	47.2%	48.6%	46.6%	48.5%	*48.0%*	*48.0%*	Common Equity Ratio	*48.0%*
5840.8	5921.2	6476.6	6461.0	7257.2	7246.3	8177.6	8192.8	9832.0	10226	*10000*	*10500*	Total Capital ($mill)	*12000*
6730.6	7037.1	7838.0	7147.3	6442.0	8970.2	9809.9	10798	12031	13527	*14000*	*15000*	Net Plant ($mill)	*18000*
6.6%	6.4%	6.3%	7.0%	6.3%	6.3%	5.6%	6.8%	6.3%	4.1%	*4.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
9.7%	9.5%	10.1%	11.0%	10.6%	10.2%	9.7%	10.9%	11.2%	10.7%	*10.5%*	*10.0%*	Return on Shr. Equity	*10.5%*
9.9%	9.5%	10.3%	11.3%	10.9%	10.2%	9.7%	6.4%	11.2%	10.7%	*10.5%*	*10.0%*	Return on Com Equity E	*10.5%*
3.8%	3.3%	3.9%	4.9%	4.3%	3.6%	2.8%	4.0%	4.4%	4.2%	*4.0%*	*3.5%*	Retained to Com Eq	*3.5%*
64%	67%	64%	57%	61%	65%	71%	63%	61%	61%	*62%*	*64%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $6461.6 mill. Due in 5 Yrs $1000.0 mill.
LT Debt $5833.9 mill. LT Interest $250.0 mill.
(LT interest earned: 3.1x)

Pension Assets-12/19 $930.4 mill. Oblig. $1279.7 mill.
Pfd Stock $400.0 mill. Pfd Div'd $10.2 mill.
16,000,000 shs.

Common Stock 249,503,754 shs.

MARKET CAP: $12.3 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-1.0	+2.0	-2.2
Avg. Indust. Use (MWH)	11769	11830	11446
Avg. Indust. Revs. per KWH (¢)	7.16	7.25	6.98
Capacity at Peak (Mw)	5375	5459	5626
Peak Load, Summer (Mw)	5375	5459	5626
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.4	+.6
Fixed Charge Cov. (%)	319	322	324

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-.5%	-.5%	*2.0%*
"Cash Flow"	4.5%	3.5%	*6.0%*
Earnings	5.0%	5.0%	*6.5%*
Dividends	7.0%	7.0%	*5.5%*
Book Value	4.0%	5.0%	*7.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	853.9	765.3	906.9	856.1	3382.2
2018	916.3	816.1	928.6	873.5	3534.5
2019	987.2	790.2	990.2	880.1	3647.7
2020	915.7	*840*	*1020*	*899.3*	*3675*
2021	*1040*	*860*	*1040*	*910*	*3850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.44	.41	.73	.41	1.99
2018	.52	.43	.87	.37	2.19
2019	.53	.40	.94	.46	2.33
2020	.72	*.43*	*.90*	*.40*	*2.45*
2021	*.60*	*.50*	*1.00*	*.45*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.295	.295	.295	.295	1.18
2017	.315	.315	.315	.315	1.26
2018	.335	.335	.335	.335	1.34
2019	.355	.355	.355	.355	1.42
2020	.38	.38			

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 42%; IA, 57%; MN, 1%. Elect. rev.: residential, 34%; commercial, 29%; industrial, 28%; wholesale, 7%; other, 2%. Fuel sources, 2019: coal, 27%; gas, 34%; other, 39%. Fuel costs: 41% of revs. 2019 depreciation rate: 5.9%. Estimated plant age: 17 years. Has approximately 3,597 employees. Chairman & Chief Executive Officer: John O. Larsen. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

We look for modest earnings increases at Alliant Energy in 2020 and 2021. The utility's largest subsidiary, Interstate Power and Light, is receiving rate relief through an order from the Iowa Utilities Board. The company's rates were increased by $127 million and $12 million for electricity and gas, respectively, at the beginning of 2020. Alliant is also benefiting from customer growth, lower fuel expenditures, cost savings, and tax credits tied to its renewable energy portfolio. Our 2020 share-net estimate, now at $2.45—up a nickel since our March review—represents growth of 5% over 2019's tally.

The COVID-19 outbreak has affected Alliant. The utility saw a 9% drop in retail power sales during the month of April, due to declines in the commercial and industrial sector, partially offset by an increase in residential activity. Although leadership kept its 2020 EPS guidance range untouched at $2.34-$2.48, it did say the pandemic has increased earnings risk through higher operating expenses and elevated macroeconomic uncertainty. The company has responded to this by deferring some capital expenditures and accelerating planned cost-saving initiatives.

Alliant has taken several steps to improve its liquidity situation. During the first quarter, it refinanced a $300 million term loan and issued $350 million in 30-year debentures for its Wisconsin Utility. Both deals were well received by the market at favorable interest rates. In addition, the company generated $222 million from common equity issuance, in line with prior projections, and reiterated its plan to move forward with a $300 million debt issuance for its Iowa utility subsidiary. At the end of March, total available liquidity, including borrowing capacity under its existing credit revolver, stood at $1.2 billion.

This stock is now ranked 2 (Above Average) for year-ahead relative price performance, having slipped a notch on our Timeliness scale since March. Like many utility issues, the recent quotation is well within our 2023-2025 Target Price Range, resulting in unexciting total return potential over that time frame. In addition, at 3.1%, the dividend yield doesn't stand out for a utility, further reducing the equity's investment appeal.

Daniel Henigson, CFA *June 12, 2020*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '10, (8¢); '11, (1¢); '12, (8¢). Next earnings rpt. due early August. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred chgs. In '19: $72.0 mill., $0.29/sh. (D) In millions, adjusted for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '19: 10.0%; in WI in '19 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	90

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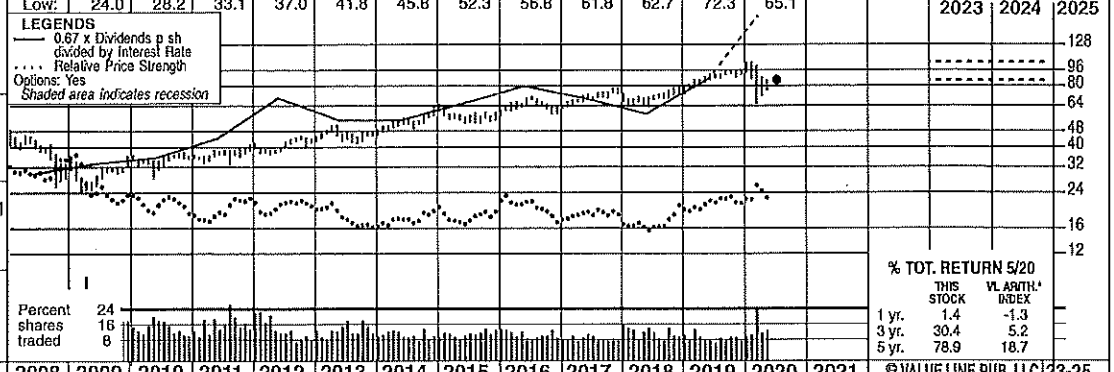
RECENT PRICE 86.14 | P/E RATIO 20.3 (Trailing: 22.0 Median: 15.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 9/6/19
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Lowered 6/12/20
BETA .75 (1.00 = Market)

High:	36.5	37.9	41.7	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0
Low:	24.0	28.2	33.1	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1

LEGENDS
— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$65-$133 $99 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+20%)	8%
Low	85	(Nil)	4%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	482	549	483
to Sell	454	459	594
Hld's(000)	368289	370323	370792

Percent shares traded 24 16 8

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.4	-1.3
3 yr.	30.4	5.2
5 yr.	78.9	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	*29.30*	*31.25*	Revenues per sh	*32.00*
5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.35	*9.80*	*10.35*	"Cash Flow" per sh	*11.50*
2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	4.08	*4.25*	*4.55*	Earnings per sh A	*5.25*
1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	*2.84*	*3.00*	Div'd Decl'd per sh B ■	*3.55*
4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	*12.25*	*13.80*	Cap'l Spending per sh	*12.50*
21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	*41.30*	*43.00*	Book Value per sh C	*50.00*
395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	*495.00*	*496.00*	Common Shs Outst'g D	*530.00*
12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	*Value Line*		Relative P/E Ratio	*1.00*
4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $32357 mill. Due in 5 Yrs $12677 mill.
LT Debt $25783 mill. LT Interest $1085 mill.
Incl. $918 mill. securitized bonds. Incl. $307 mill. capitalized leases.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $269.9 mill.
Pension Assets-12/19 $5015.4 mill. Oblig $5236.8 mill.

Pfd Stock None

Common Stock 495,583,133 shs. as of 5/6/20
MARKET CAP: $43 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
14427	15116	14945	15357	17020	16453	16380	15425	16196	15561	*14500*	*15500*	Revenues ($mill)	*17000*
1248.0	1513.0	1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	*2115*	*2265*	Net Profit ($mill)	*2785*
34.8%	31.7%	33.9%	36.2%	37.6%	35.1%	26.8%	33.7%	5.8%	.7%	*2.0%*	*2.0%*	Income Tax Rate	*2.0%*
10.4%	10.6%	11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	*12.0%*	*11.0%*	AFUDC % to Net Profit	*9.0%*
53.1%	50.7%	50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	*56.5%*	*55.5%*	Long-Term Debt Ratio	*53.0%*
46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	*43.5%*	*44.5%*	Common Equity Ratio	*47.0%*
29184	29747	30823	32913	33001	35633	34775	37707	40677	44759	*46850*	*47775*	Total Capital ($mill)	*56700*
35674	36971	38763	40997	44117	46133	45639	50262	55099	60138	*63475*	*67450*	Net Plant ($mill)	*77900*
5.7%	6.6%	6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.5%*
9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	*10.5%*	*10.5%*	Return on Com Equity E	*10.5%*
3.1%	4.2%	3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
66%	60%	63%	62%	61%	60%	54%	67%	65%	67%	*69%*	*68%*	All Div'ds to Net Prof	*69%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-1.6	+3.0	-2.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	+.3
Fixed Charge Cov. (%)	354	254	234

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	--	-.5%	*Nil*
"Cash Flow"	2.5%	4.0%	*5.0%*
Earnings	3.0%	4.0%	*5.0%*
Dividends	4.5%	5.5%	*5.5%*
Book Value	4.0%	3.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	3933	3576	4104	3810	15424
2018	4048	4013	4333	3801	16195
2019	4056	3573	4315	3616	15561
2020	3748	*3252*	*4000*	*3500*	*14500*
2021	*4100*	*3550*	*4300*	*3550*	*15500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.94	.76	1.11	.81	3.62
2018	.92	1.07	1.17	.74	3.90
2019	1.16	.93	1.48	.51	4.08
2020	1.00	*1.00*	*1.50*	*.75*	*4.25*
2021	*1.15*	*1.05*	*1.60*	*.75*	*4.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.56	.56	.56	.59	2.27
2017	.59	.59	.59	.62	2.39
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	2.71
2020	.70	.70			

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 42%; commercial, 24%; industrial, 19%; wholesale, 11%; other, 4%. Sold Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '19 reported depreciation rates (utility): 1.8%-9.5%. Has 17,400 employees. Chairman, President & CEO: Nicholas K. Akins. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

We reduced our 2020 earnings estimate for American Electric Power by $0.10 a share. First-quarter earnings fell short of our estimate, and the year-earlier tally, due to mild winter weather patterns. Another negative factor is declining kilowatt-hour sales due to the poor economy. AEP's weather-adjusted volume fell 4.3% in April. In response, the company deferred $500 million of capital spending planned for 2020 and is cutting operating and maintenance expenses. Management retained its 2020 guidance of $4.25-$4.45 a share, but stated that earnings are likely to wind up in the lower half of this range.

The company has obtained three regulatory approvals for a proposed wind project. AEP wants to spend $2 billion to build 1,485 megawatts of capacity to serve Oklahoma, Texas, Arkansas, and Louisiana. This consists of three wind farms, one to be completed this year, the others in 2021. The project has been approved in Oklahoma, Arkansas, and Louisiana, and will be built in full even if the Texas commission does not approve it. AEP expects this to provide about $100 million to net profit beginning in 2022.

A rate order was received in Indiana, and others are pending or upcoming. On March 11th, the utility was granted an increase of $26 million (net of higher depreciation), based on a 9.7% return on equity. In Virginia, Appalachian Power filed for a hike of $65 million (net of a depreciation increase), based on a 9.9% ROE. New tariffs are expected to take effect in the first quarter of 2021. AEP plans to file applications in Kentucky, Ohio (a modest one), and Louisiaua in the next few months.

We trimmed our 2021 earnings estimate by $0.05 a share, to $4.55. This would still provide a solid increase over the 2020 tally. We assume normal weather conditions in the first quarter, a recovering economy, and rate relief. Also, note that AEP's transmission business is not sensitive to changes in kilowatt-hour sales.

This high-quality stock has a dividend yield that is about average for a utility. Total return potential for the 18-month span is average, but isn't appealing over the 3- to 5-year time fraune.

Paul E. Debbas, CFA *June 12, 2020*

(A) Diluted EPS. Excl. nonrec. gains (losses): '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; '19, (20¢); disc. ops.: '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). Next earnings report due early Aug. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '19: $13.39/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.3%-10.9%; earned on avg. com. eq., '19: 10.4%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

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AMEREN NYSE-AEE

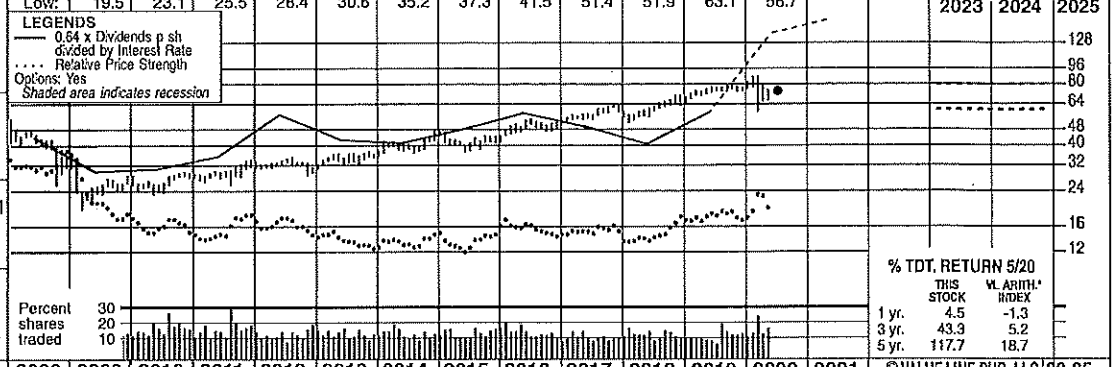
RECENT PRICE 74.37 | P/E RATIO 21.6 (Trailing: 23.5 Median: 17.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Lowered 3/29/19
SAFETY 2 Raised 6/20/14
TECHNICAL 1 Raised 5/8/20
BETA .80 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
High:	35.3	29.9	34.1	35.3	37.3	46.1	46.8	54.1	64.9	70.9	80.9	87.7
Low:	19.5	23.1	25.5	26.4	30.6	35.2	37.3	41.5	51.4	51.9	63.1	56.7

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.64 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$56-$117	$87 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+10%)	5%
Low	60	(-20%)	-1%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	257	266	242
to Sell	257	265	273
Hld's(000)	186859	186367	187833

Percent shares traded 30 20 10

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.5	-1.3
3 yr.	43.3	5.2
5 yr.	117.7	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	24.00	*22.05*	*22.70*	Revenues per sh	*24.25*
5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	7.83	*8.05*	*8.50*	"Cash Flow" per sh	*10.00*
2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	3.35	*3.45*	*3.65*	Earnings per sh A	*4.50*
2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	1.92	*2.01*	*2.11*	Div'd Decl'd per sh B ■	*2.45*
4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	9.92	*15.85*	*11.55*	Cap'l Spending per sh	*11.00*
29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	32.73	*35.70*	*37.40*	Book Value per sh C	*43.50*
195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	246.20	*254.00*	*260.00*	Common Shs Outst'g D	*275.00*
16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	22.1	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	*Value Line*		Relative P/E Ratio	*.85*
5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $10350 mill. Due in 5 Yrs $2660 mill.
LT Debt $9378 mill. LT Interest $428 mill.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $8 mill.
Pension Assets-12/19 $4564 mill.
Oblig $4967 mill.
Pfd Stock $142 mill. Pfd Div'd $6 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 246,891,031 shs. as of 4/30/20
MARKET CAP: $18 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
7638.0	7531.0	6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	*5600*	*5900*	Revenues ($mill)	*6700*
669.0	602.0	589.0	518.0	593.0	585.0	659.0	683.0	821.0	834.0	*875*	*950*	Net Profit ($mill)	*1230*
36.8%	37.3%	36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	*12.5%*	*12.5%*	Income Tax Rate	*12.5%*
7.8%	5.6%	6.1%	7.1%	5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
48.2%	45.3%	49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	*54.0%*	*51.0%*	Long-Term Debt Ratio	*49.5%*
50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	*45.5%*	*48.5%*	Common Equity Ratio	*50.0%*
15185	14738	13384	12190	12975	13968	13840	14420	15632	17116	*20000*	*20150*	Total Capital ($mill)	*23900*
17853	18127	16096	16205	17424	18799	20113	21466	22810	24376	*27225*	*28950*	Net Plant ($mill)	*33600*
6.0%	5.6%	6.0%	5.6%	5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
8.5%	7.5%	8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	*9.5%*	*9.5%*	Return on Com Equity E	*10.0%*
3.8%	2.8%	3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
56%	63%	66%	76%	67%	70%	64%	64%	56%	57%	*58%*	*58%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-3.4	+5.6	-3.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	350	313	307

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-3.0%	-.5%	-.5%
"Cash Flow"	1.5%	5.5%	*5.0%*
Earnings	1.0%	6.5%	*6.0%*
Dividends	-2.0%	3.0%	*5.0%*
Book Value	-.5%	2.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1514	1538	1723	1402	6177.0
2018	1585	1563	1724	1419	6291.0
2019	1556	1379	1659	1316	5910.0
2020	1440	*1300*	*1600*	*1260*	*5600*
2021	*1600*	*1350*	*1650*	*1300*	*5900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.42	.79	1.18	.39	2.77
2018	.62	.97	1.45	.28	3.32
2019	.78	.72	1.47	.38	3.35
2020	.59	*.80*	*1.61*	*.45*	*3.45*
2021	*.65*	*.85*	*1.70*	*.45*	*3.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.425	.425	.425	.44	1.72
2017	.44	.44	.44	.4575	1.78
2018	.4575	.4575	.4575	.475	1.85
2019	.475	.475	.475	.495	1.92
2020	.495	.495			

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 43%; commercial, 32%; industrial, 8%; other, 17%. Generating sources: coal, 63%; nuclear, 23%; hydro & other, 6%; purchased, 8%. Fuel costs: 24% of revenues. '19 reported deprec. rates: 3%-4%. Has 9,300 employees. Chairman, President & CEO: Warner L. Baxter. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, Missouri 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

We cut our 2020 and 2021 earnings estimates for Ameren. The company's electric business in Missouri is being hurt by kilowatt-hour sales reductions resulting from the weak economy. Ameren's electric operations in Illinois have had a cut in the allowed return on equity, which tracks the 30-year U.S. Treasury bond rate. At least Ameren Illinois isn't being hurt by a decline in sales because it operates under a regulatory mechanism that decouples volume and revenues. Moreover, the company's transmission business does not depend on retail sales. We lowered our 2020 earnings estimate by $0.05 a share, to $3.45. This is still within the company's guidance of $3.40-$3.60, which management did not change upon releasing March-quarter results. Because any growth in 2021 will come off a lower base, we cut our estimate by $0.10 a share, to $3.65. The 6% increase we estimate for next year is within Ameren's target of 6%-8% for annual profit growth.

Ameren's electric rates were reduced in Missouri, but this wasn't a bad outcome for the utility. The commission cut Ameren's rates by $32 million, effective April 1, 2020. But this included the pass-through to customers of some $115 million of lower fuel costs and $50 million of decreased nonfuel expenses. This was a "black box" order in which an allowed ROE and common-equity ratio were not specified, but the decision was based on an implicit ROE in a range of 9.4%-9.8%.

A gas rate application is pending in Illinois. Ameren filed for $102 million, including $46 million that would otherwise be recovered through riders (surcharges) on customers' bills. The utility requested a 10.5% ROE and a 54.1% common-equity ratio. A ruling is due by January, with new tariffs taking effect in February.

Ameren is adding wind projects. The company is spending $1.2 billion to add 700 megawatts of capacity. Most, if not all, of this should be in service by yearend.

The stock has outperformed most utility equities in 2020. Its price has fallen just 3%. The dividend yield is almost one percentage point below the industry average. Total return potential is average for the next 18 months, but not for the 2023-2025 period.

Paul E. Debbas, CFA *June 12, 2020*

(A) Dil. EPS. Excl. nonrec. gain (losses): '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from disc. ops.: '13, (92¢); '15, 21¢. '17 EPS don't sum due to rounding. Next egs. report due early Aug. (B) Div'ds pd. late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $5.70/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd on com. eq. in MO in '20: elec., none; in '11: gas, none; in IL in '14: elec., 8.7%, in '18: gas, 9.87%; earned on avg. com. eq., '19: 10.5%. Reg. Climate: MO, Avg.; IL, Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	85

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AVANGRID, INC. NYSE-AGR

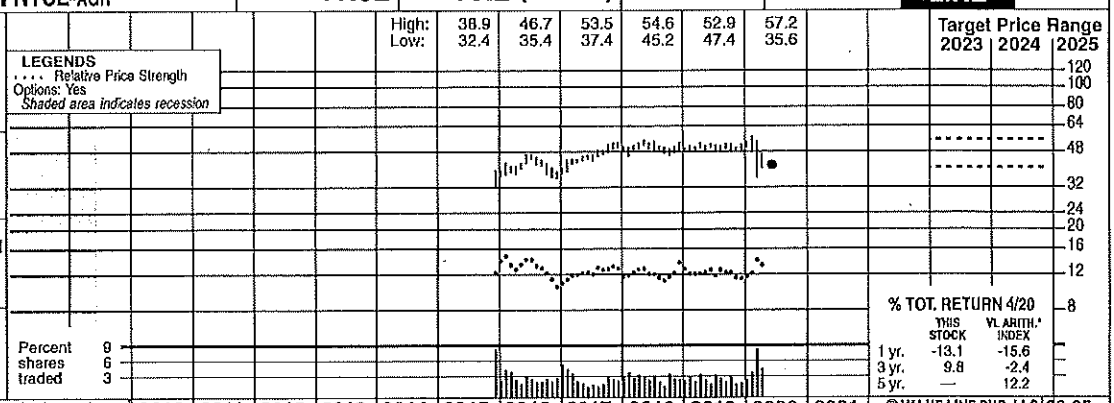
RECENT PRICE 41.32 | P/E RATIO 19.2 (Trailing: 17.7 Median: NMF) | RELATIVE P/E RATIO 1.16 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Lowered 3/22/19
SAFETY 2 Raised 2/17/17
TECHNICAL 3 Raised 4/10/20
BETA .60 (1.00 = Market)

High:	38.9	46.7	53.5	54.6	52.9	57.2						
Low:	32.4	35.4	37.4	45.2	47.4	35.6						

Target Price Range 2023 | 2024 | 2025

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$34-$75	$55 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+35%)	11%
Low	40	(-5%)	4%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	114	118	142
to Sell	138	111	101
Hld's(000)	43692	45639	46257

Percent shares traded 9 6 3

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-13.1	-15.6
3 yr.	9.8	-2.4
5 yr.	—	12.2

AVANGRID, Inc. was formed through a merger between Iberdrola USA, Inc. and UIL Holdings Corporation in December of 2015. Iberdrola S.A., a worldwide leader in the energy industry, owns 81.5% of AVANGRID. The predecessor company was founded in 1852 and is headquartered in New Gloucester, Maine. It was incorporated in 1997 in New York under the name NGE Resources, Inc. AVANGRID began trading on the NYSE on December 17, 2015.

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
--	--	--	--	--	14.14	19.48	19.30	20.96	20.51	*20.40*	*21.05*	Revenues per sh	*23.25*
--	--	--	--	--	3.44	4.74	4.49	4.89	5.50	*5.55*	*5.80*	"Cash Flow" per sh	*6.75*
--	--	--	--	--	1.05	1.98	1.67	1.92	2.26	*2.15*	*2.30*	Earnings per sh A	*2.75*
--	--	--	--	--	--	1.73	1.73	1.74	1.76	*1.76*	*1.76*	Div'd Decl'd per sh B ■	*2.00*
--	--	--	--	--	3.50	5.52	7.82	5.78	8.87	*10.05*	*10.35*	Cap'l Spending per sh	*9.75*
--	--	--	--	--	48.74	48.90	48.79	48.88	49.31	*49.70*	*50.25*	Book Value per sh C	*52.50*
--	--	--	--	--	308.86	308.99	309.01	309.01	309.01	*309.00*	*309.00*	Common Shs Outst'g D	*309.00*
--	--	--	--	--	33.5	20.5	27.3	26.1	22.1	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
--	--	--	--	--	1.69	1.08	1.37	1.41	1.19	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	--	--	--	4.3%	3.8%	3.5%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*
--	--	--	--	4594.0	4367.0	6018.0	5963.0	6478.0	6338.0	*6300*	*6500*	Revenues ($mill)	*7150*
--	--	--	--	424.0	267.0	611.0	516.0	595.0	700.0	*670*	*715*	Net Profit ($mill)	*865*
--	--	--	--	39.9%	11.3%	37.4%	32.4%	22.1%	17.5%	*7.0%*	*7.0%*	Income Tax Rate	*7.0%*
--	--	--	--	6.8%	12.7%	7.5%	12.4%	9.4%	14.4%	*15.0%*	*14.0%*	AFUDC % to Net Profit	*12.0%*
--	--	--	--	16.8%	23.1%	23.0%	25.6%	26.2%	30.6%	*33.5%*	*36.0%*	Long-Term Debt Ratio	*42.0%*
--	--	--	--	83.2%	76.9%	77.0%	74.4%	73.8%	69.4%	*66.5%*	*64.0%*	Common Equity Ratio	*58.0%*
--	--	--	--	14956	19583	19619	20273	20472	21953	*23150*	*24350*	Total Capital ($mill)	*28100*
--	--	--	--	17099	20711	21548	22669	23459	25218	*27275*	*29400*	Net Plant ($mill)	*34800*
--	--	--	--	3.7%	2.1%	3.8%	3.1%	3.5%	3.8%	*3.5%*	*3.5%*	Return on Total Cap'l	*4.0%*
--	--	--	--	3.4%	1.8%	4.0%	3.4%	3.9%	4.6%	*4.5%*	*4.5%*	Return on Shr. Equity	*5.5%*
--	--	--	--	3.4%	1.8%	4.0%	3.4%	3.9%	4.6%	*4.5%*	*4.5%*	Return on Com Equity E	*5.5%*
--	--	--	--	3.4%	1.8%	1.4%	NMF	.4%	1.0%	*1.0%*	*1.0%*	Retained to Com Eq	*1.5%*
--	--	--	--	--	--	66%	104%	90%	78%	*81%*	*76%*	All Div'ds to Net Prof	*72%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $8188 mill. Due in 5 Yrs $3692 mill.
LT Debt $6715 mill. LT Interest $270 mill.
Incl. $63 mill. capitalized leases.
(LT interest earned: 3.7x)
Leases, Uncapitalized Annual rentals $14 mill.

Pension Assets-12/19 $2848 mill. Oblig $3669 mill.

Pfd Stock None

Common Stock 309,005,485 shs.
as of 4/30/20
MARKET CAP: $13 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.5	NA
Fixed Charge Cov. (%)	333	343	278

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	--	--	*2.5%*
"Cash Flow"	--	--	*5.5%*
Earnings	--	--	*6.0%*
Dividends	--	--	*2.5%*
Book Value	--	--	*1.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1758	1331	1341	1533	5963.0
2018	1865	1402	1546	1665	6478.0
2019	1842	1400	1487	1609	6338.0
2020	1782	*1400*	*1500*	*1618*	*6300*
2021	*1900*	*1400*	*1550*	*1650*	*6500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.77	.39	.32	.19	1.67
2018	.79	.34	.40	.38	1.92
2019	.70	.36	.48	.72	2.26
2020	.78	*.40*	*.50*	*.47*	*2.15*
2021	*.85*	*.42*	*.53*	*.50*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	--	.432	.432	.432	1.30
2017	.432	.432	.432	.432	1.73
2018	.432	.432	.432	.44	1.74
2019	.44	.44	.44	.44	1.76
2020	.44	.44			

BUSINESS: AVANGRID, Inc. (formerly Iberdrola USA, Inc.), is a diversified energy and utility company that serves 2.2 million electric customers in New York, Connecticut, and Maine and 1 million gas customers in New York, Connecticut, Massachusetts & Maine. Has a nonregulated generating subsidiary focused on wind power, with 7.2 gigawatts of capacity. Revenue breakdown by customer class not available. Generating sources not available. Fuel costs: 24% of revenues. '19 reported depr. rate (utility): 2.9%. Iberdrola owns 81.5% of stock. Has 6,400 employees. Chairman: José Ignacio Sanchez Galan. CEO: James P. Torgerson. Deputy CEO & President: Robert Kump. Inc.: NY. Address: 180 Marsh Hill Road, Orange, CT 06477. Tel.: 207-629-1200. Web: www.avangrid.com.

We estimate that AVANGRID's 2020 earnings will wind up below the 2019 tally. The company's utilities should benefit from rate relief (see below). AVANGRID's renewable-energy subsidiary plans to add and repower 908 megawatts of capacity this year, and in the first quarter benefited from wind conditions that were much better than a year earlier and also above normal. On the other hand, the December-quarter comparison will be difficult because the company recorded a gain of $0.32 a share on the sale of two renewable-energy assets last year. (We *include* this in our earnings presentation because such sales are a normal part of this business.) Our previous 2020 share-net estimate was too high, so we cut it by $0.30, to $2.15. This puts it within management's guidance (on a GAAP basis) of $2.06-$2.26.

The company was granted a rate increase in Maine, and is trying to reach settlements of its cases in New York. Central Maine Power received a tariff hike of $17.4 million (6.9%), based on a 9.25% return on equity, effective March 1st. However, the regulators penalized the utility by cutting the allowed ROE to 8.25% until certain customer-service measures are attained for an 18-month period. In New York, AVANGRID's utilities are seeking $188.4 million (electric) and $12.1 million (gas), based on a 9.5% ROE and a 50% common-equity ratio. New tariffs might not take effect until September 1st, but the company is asking for a make-whole provision dating back to April 17tb.

We have also lowered our 2021 share-earnings estimate by $0.30. Even so, our revised estimate would produce a solid increase over our 2020 expectation. AVANGRID should benefit from rate relief and additional renewable-energy projects.

AVANGRID is seeking permits and approvals for some large capital projects. Central Maine Power wauts to build a $950 million transmission line. The company also wants to build some offshore wind projects through a joint venture.

The stock's yield is slightly above average for a utility. However, the company faces regulatory risk and construction risk associated with offshore wind. Moreover, a dividend hike is unlikely in the near term due to the high payout ratio.

Paul E. Debbas, CFA *May 15, 2020*

(A) Diluted EPS. Excl. nonrecurring gain (loss): '16, 6¢; '17, (44¢). '18 EPS don't sum due to rounding. Next earnings report due late July. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '19: $6.0 bill., $19.42/sh. (D) In millions. (E) Rate base: net original cost. Rate allowed on com. eq. in NY in '16: 9.6%; in CT in '17: 9.1% elec.; in CT in '19: 9.3% gas; in ME in '20: 8.25%; earned on avg. common eq., '19: 4.6%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	80
Earnings Predictability	55

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AVISTA CORP. NYSE-AVA

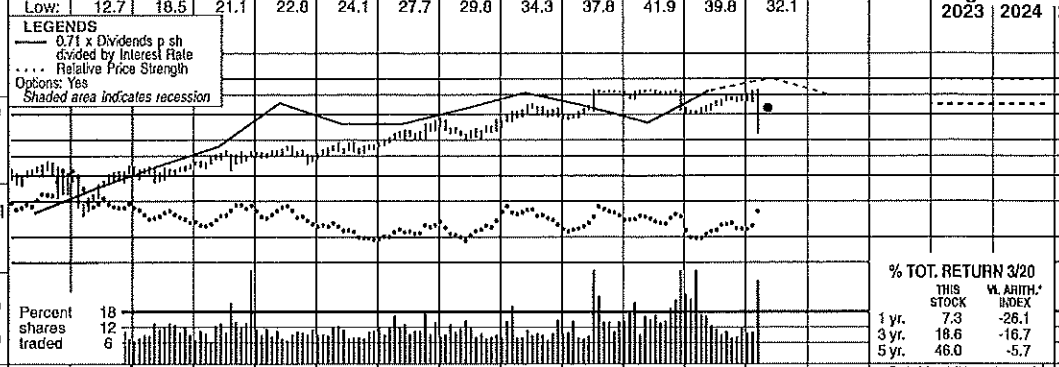
RECENT PRICE 43.12 | P/E RATIO 21.5 (Trailing: 14.5 Median: 17.0) | RELATIVE P/E RATIO 1.47 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 New 12/14/18
SAFETY 2 Raised 5/7/10
TECHNICAL 2 Raised 4/17/20
BETA .60 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
High:	22.4	22.8	26.5	28.0	29.3	37.4	38.3	45.2	52.8	52.9	49.5	53.0
Low:	12.7	18.5	21.1	22.8	24.1	27.7	29.8	34.3	37.8	41.9	39.8	32.1

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.71 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$38-$57	$48 (10%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+40%)	12%
Low	45	(+5%)	5%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	131	121	121
to Sell	108	103	120
Hld's(000)	53198	53961	54694

Percent shares traded 18 12 6

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.3	-26.1
3 yr.	18.6	-16.7
5 yr.	46.0	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
23.76	27.98	28.68	26.80	30.77	27.58	27.29	27.73	25.86	26.94	23.66	23.83	22.47	22.08	21.27	20.03	*20.40*	*20.70*	Revenues per sh	*22.00*
2.35	2.72	4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	5.30	4.87	5.01	6.06	*5.20*	*5.55*	"Cash Flow" per sh	*6.25*
.73	.92	1.47	.72	1.36	1.58	1.65	1.72	1.32	1.85	1.84	1.89	2.15	1.95	2.07	2.97	*1.95*	*2.20*	Earnings per sh A	*2.50*
.52	.55	.57	.60	.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	1.37	1.43	1.49	1.55	*1.62*	*1.68*	Div'd Decl'd per sh B ■	*1.90*
2.47	3.23	3.14	4.04	4.09	3.86	3.64	4.20	4.61	5.05	5.47	6.46	6.34	6.30	6.46	6.59	*6.25*	*6.15*	Cap'l Spending per sh	*6.00*
15.54	15.87	17.46	17.27	18.30	19.17	19.71	20.30	21.06	21.61	23.84	24.53	25.69	26.41	26.99	28.87	*29.45*	*30.10*	Book Value per sh C	*32.50*
48.47	48.59	52.51	52.91	54.49	54.84	57.12	58.42	59.81	60.08	62.24	62.31	64.19	65.49	65.69	67.18	*68.70*	*70.00*	Common Shs Outst'g D	*71.00*
24.4	19.4	15.4	30.9	15.0	11.4	12.7	14.1	19.3	14.6	17.3	17.6	18.8	23.4	24.5	15.0	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
1.29	1.03	.83	1.64	.90	.76	.81	.88	1.23	.82	.91	.89	.99	1.18	1.32	.81	*Value Line*		Relative P/E Ratio	*1.10*
2.9%	3.0%	2.5%	2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%	4.0%	3.4%	3.1%	2.9%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $2133.1 mill. Due in 5 Yrs $516.3 mill.
LT Debt $1695.3 mill. LT Interest $86.9 mill.
Incl. $51.5 mill. debt to affiliated trusts; $54.5 mill. capitalized leases.
(LT interest earned: 3.7x)
Leases, Uncapitalized Annual Rentals $4.4 mill.
Pension Assets-12/19 $642.1 mill. Oblig $742.4 mill.

Pfd Stock None
Common Stock 67,208,604 shs. as of 1/31/20

MARKET CAP: $2.9 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
1558.7	1619.8	1547.0	1618.5	1472.6	1484.8	1442.5	1445.9	1396.9	1345.6	*1400*	*1450*	Revenues ($mill)	*1600*
92.4	100.2	78.2	111.1	114.2	118.1	137.2	126.1	136.4	197.0	*135*	*150*	Net Profit ($mill)	*185*
35.0%	35.4%	34.4%	36.0%	37.6%	36.3%	36.3%	36.5%	16.0%	13.8%	*16.5%*	*16.5%*	Income Tax Rate	*16.5%*
4.0%	5.2%	8.3%	8.8%	11.1%	10.1%	8.1%	7.9%	7.7%	5.5%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
51.6%	51.4%	50.8%	51.4%	51.0%	50.0%	51.2%	47.2%	50.5%	49.4%	*50.5%*	*49.0%*	Long-Term Debt Ratio	*50.5%*
48.4%	48.6%	49.2%	48.6%	49.0%	50.0%	48.8%	52.8%	49.5%	50.6%	*49.5%*	*51.0%*	Common Equity Ratio	*49.5%*
2325.3	2439.9	2561.2	2669.7	3027.3	3060.3	3379.0	3273.2	3580.3	3834.6	*4080*	*4150*	Total Capital ($mill)	*4800*
2714.2	2860.8	3023.7	3202.4	3620.0	3898.6	4147.5	4398.8	4648.9	4797.0	*5000*	*5195*	Net Plant ($mill)	*5700*
5.4%	5.5%	4.3%	5.4%	4.9%	5.1%	5.3%	5.0%	4.8%	6.2%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	*6.5%*	*7.0%*	Return on Shr. Equity	*8.0%*
8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	*6.5%*	*7.0%*	Return on Com Equity E	*8.0%*
3.3%	3.1%	.8%	2.9%	2.4%	2.3%	3.0%	1.9%	2.2%	4.9%	*1.0%*	*1.5%*	Retained to Com Eq	*2.0%*
60%	64%	88%	66%	69%	70%	64%	73%	72%	52%	*83%*	*77%*	All Div'ds to Net Prof	*74%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+4.7	-3.7	+.2
Avg. Indust. Use (MWH)	1367	1344	1296
Avg. Indust. Revs. per KWH (¢)	6.11	6.20	6.26
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)F	1681	1716	1656
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.4	+1.3
Fixed Charge Cov. (%)	296	259	202

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-3.0%	-3.5%	.5%
"Cash Flow"	3.5%	5.0%	2.5%
Earnings	6.5%	7.0%	1.0%
Dividends	8.0%	4.0%	4.0%
Book Value	4.0%	4.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	436.5	314.5	297.1	397.8	1445.9
2018	409.4	319.3	296.0	372.2	1396.9
2019	396.5	300.8	283.8	364.5	1345.6
2020	*410*	*315*	*295*	*380*	*1400*
2021	*425*	*325*	*305*	*395*	*1450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.96	.34	.07	.58	1.95
2018	.83	.39	.15	.70	2.07
2019	1.76	.38	.08	.76	2.97
2020	*.75*	*.40*	*.10*	*.70*	*1.95*
2021	*.90*	*.45*	*.10*	*.75*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.3425	.3425	.3425	.3425	1.37
2017	.3575	.3575	.3575	.3575	1.43
2018	.3725	.3725	.3725	.3725	1.49
2019	.3875	.3875	.3875	.3875	1.55
2020	.405				

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 410,000 electric, 361,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 39%; commercial, 33%; industrial, 11%; wholesale, 8%; other, 9%. Generating sources: gas & coal, 34%; hydro, 30%; purch., 36%. Fuel costs: 33% of revs. '19 reported depr. rate (Avista Utilities): 3.3%. Has 1,900 employees. Chairman: Scott L. Morris. Pres. & CEO: Dennis Vermillion. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Internet: www.avistacorp.com.

Two of Avista's regulatory matters were resolved in the March quarter. The Washington Utilities and Transportation Commission (WUTC) raised the company's electric and gas rates by $28.5 million (5.7%) and $8.0 million (8.5%), respectively, on April 1st. The allowed return on equity was trimmed to 9.4% (from 9.5%) and the common-equity ratio remained at 48.5%. However, the WUTC disallowed $3 million of replacement power costs that Avista booked in 2018. Separately, the appeal of the utility's 2015 rate case was resolved. The state attorney general's office had appealed the order, contending that some previously collected revenues should be refunded to customers. The WUTC ordered Avista to refund $8.4 million (above the $3.6 million reserve the company took last year). Along with the disallowance, this will reduce first-quarter earnings by $0.09 a share. Accordingly, we cut our 2020 estimate by $0.10, to $1.95.

Profits will almost certainly return to a more-typical level in 2020. Earnings in the first quarter of 2019 benefited from a breakup fee that raised the bottom line by $1.01 a share. Although Avista will benefit from rate relief, the utility will still underearn its allowed ROE due to regulatory lag and structural reasons. Our estimate is at the low end of management's targeted range of $1.95-$2.15. Any decline in volume should have a limited effect on income because revenues and sales are decoupled for residential and commercial customers in each state except Alaska.

A rate case is pending, and two more are upcoming. Avista asked the Oregon commission for a gas tariff increase of $6.8 million (6.8%), based on a 9.9% ROE and a 50% common-equity ratio. New rates should take effect in January. The company plans to file rate applications in Washington in the second or third quarter and in Idaho in the second half of 2020.

The board of directors raised the dividend in the first quarter. The increase was $0.06 a share (4.5%) annually. Avista is above its payout-ratio goal of 65%-75%.

The stock's yield is a cnt above the utility average. The price is down 10% in 2020, in line with many utilities. Total return potential doesn't stand out for a utility for the 18-month or 3- to 5-year period.

Paul E. Debbas, CFA *April 24, 2020*

(A) Diluted EPS. Excl. nonrec. gain (loss): '14, 9¢; '17, (16¢); gains on disc. ops.: '14, $1.17; '15, 8¢. '19 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred chgs. In '19: $10.77/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in WA in '20: 9.4%; in ID in '17: 9.5%; in OR in '17: 9.4%; earned on avg. com. eq., '19: 10.6%. Regulatory Climate: WA, Below Average; ID, Above Average. (F) Winter peak in '17.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	65

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BLACK HILLS CORP. NYSE-BKH

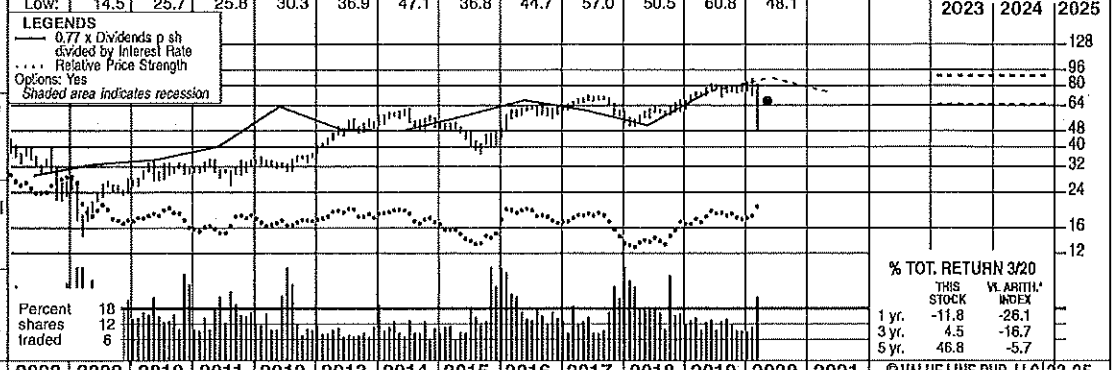
RECENT PRICE 67.69 | P/E RATIO 18.6 (Trailing: 19.1 Median: 19.0) | RELATIVE P/E RATIO 1.27 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Lowered 9/20/19
SAFETY 2 Raised 5/1/15
TECHNICAL 3 Raised 3/13/20
BETA .65 (1.00 = Market)

High:	28.0	34.5	34.8	37.0	55.1	62.1	53.4	64.6	72.0	68.2	82.0	87.1
Low:	14.5	25.7	25.8	30.3	36.9	47.1	36.8	44.7	57.0	50.5	60.8	48.1

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.77 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$62-$95	$79 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+35%)	10%
Low	65	(-5%)	3%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	148	145	144
to Sell	128	133	137
Hld's(000)	54551	53817	53772

Percent shares traded 18 12 6

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.8	-26.1
3 yr.	4.5	-16.7
5 yr.	46.8	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
34.54	41.97	19.69	18.41	26.03	32.58	33.29	28.96	26.55	28.67	31.20	25.48	29.47	31.38	29.24	28.22	*27.90*	*28.15*	Revenues per sh	*30.50*
4.46	4.81	5.04	5.29	2.95	5.41	4.88	4.01	5.59	5.93	6.25	5.67	6.28	7.15	6.81	7.02	*7.15*	*7.50*	"Cash Flow" per sh	*8.50*
1.74	2.11	2.21	2.68	.18	2.32	1.66	1.01	1.97	2.61	2.89	2.83	2.63	3.38	3.47	3.53	*3.55*	*3.80*	Earnings per sh A	*4.25*
1.24	1.28	1.32	1.37	1.40	1.42	1.44	1.46	1.48	1.52	1.56	1.62	1.68	1.81	1.93	2.05	*2.17*	*2.31*	Div'd Decl'd per sh B ■	*2.75*
2.80	4.18	9.24	6.92	8.51	8.90	12.04	10.03	7.90	7.97	8.92	8.90	8.89	6.09	7.62	13.31	*10.65*	*8.65*	Cap'l Spending per sh	*7.25*
22.43	22.29	23.68	25.66	27.19	27.84	28.02	27.53	27.88	29.39	30.80	28.63	30.25	31.92	36.36	38.42	*40.60*	*42.50*	Book Value per sh C	*47.00*
32.48	33.16	33.37	37.80	38.64	38.97	39.27	43.92	44.21	44.50	44.67	51.19	53.38	53.54	60.00	61.48	*62.75*	*64.00*	Common Shs Outst'g D	*64.00*
17.1	17.3	15.8	15.0	NMF	9.9	18.1	31.1	17.1	18.2	19.0	16.1	22.3	19.5	16.8	21.2	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
.90	.92	.85	.80	NMF	.66	1.15	1.95	1.09	1.02	1.00	.81	1.17	.98	.91	1.15	*Value Line*		Relative P/E Ratio	*1.05*
4.2%	3.5%	3.6%	3.4%	4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%	3.5%	2.9%	2.7%	3.3%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $3495.3 mill. Due in 5 Yrs $891.5 mill.
LT Debt $3140.1 mill. LT Interest $131.9 mill.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $1.0 mill.

Pension Assets-12/19 $434.3 mill. Oblig $485.4 mill.

Pfd Stock None

Common Stock 62,750,615 shs. as of 3/2/20

MARKET CAP: $4.2 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
1307.3	1272.2	1173.9	1275.9	1393.6	1304.6	1573.0	1680.3	1754.3	1734.9	*1750*	*1800*	Revenues ($mill)	*1950*
64.6	40.4	86.9	115.8	128.8	128.3	140.3	186.5	192.5	214.5	*220*	*240*	Net Profit ($mill)	*270*
26.4%	31.1%	35.5%	34.7%	33.7%	35.8%	25.1%	28.7%	19.2%	13.0%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
28.0%	65.0%	5.4%	2.4%	2.4%	2.7%	5.3%	2.7%	1.4%	3.3%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
51.9%	51.4%	43.2%	51.6%	47.9%	56.0%	66.5%	64.5%	57.5%	57.1%	*55.0%*	*53.5%*	Long-Term Debt Ratio	*51.5%*
48.1%	48.6%	56.8%	48.4%	52.1%	44.0%	33.5%	35.5%	42.5%	42.9%	*45.0%*	*46.5%*	Common Equity Ratio	*48.5%*
2286.3	2489.7	2171.4	2704.7	2643.6	3332.7	4825.8	4818.4	5132.4	5502.2	*5690*	*5860*	Total Capital ($mill)	*6225*
2495.4	2789.6	2742.7	2990.3	3239.4	3259.1	4469.0	4541.4	4854.9	5503.2	*5945*	*6260*	Net Plant ($mill)	*6900*
4.4%	3.3%	5.5%	5.5%	6.1%	4.9%	4.0%	5.2%	5.0%	4.9%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	6.7%	10.9%	8.8%	9.1%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	*8.5%*	*9.0%*	Return on Com Equity E	*9.0%*
.7%	NMF	1.8%	3.7%	4.3%	3.8%	3.3%	5.3%	3.9%	3.8%	*3.5%*	*3.5%*	Retained to Com Eq	*3.0%*
87%	NMF	75%	58%	54%	57%	62%	52%	55%	58%	*61%*	*61%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+.9	+2.7	+2.1
Avg. Indust. Use (MWH)	18376	19789	21406
Avg. Indust. Revs. per KWH (¢)	7.69	7.41	7.38
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1094	1104	1022
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+.8	+1.1
Fixed Charge Cov. (%)	296	276	278

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	1.5%	.5%	.5%
"Cash Flow"	4.5%	3.0%	3.5%
Earnings	7.0%	7.0%	3.5%
Dividends	3.5%	5.0%	6.0%
Book Value	3.0%	4.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	547.5	341.9	335.6	455.3	1680.3
2018	575.4	355.7	322.0	501.2	1754.3
2019	597.8	333.9	325.5	477.7	1734.9
2020	*600*	*345*	*330*	*475*	*1750*
2021	*615*	*355*	*340*	*490*	*1800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.42	.41	.52	1.03	3.38
2018	1.59	.45	.32	1.11	3.47
2019	1.73	.24	.44	1.13	3.53
2020	*1.65*	*.40*	*.45*	*1.05*	*3.55*
2021	*1.75*	*.45*	*.50*	*1.10*	*3.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.42	.42	.42	.42	1.68
2017	.445	.445	.445	.475	1.81
2018	.475	.475	.475	.505	1.93
2019	.505	.505	.505	.535	2.05
2020	.535				

BUSINESS: Black Hills Corporation is a holding company for Black Hills Energy, which serves 214,000 electric customers in CO, SD, WY and MT, and 1.1 million gas customers in NE, IA, KS, CO, WY, and AR. Has coal mining sub. Acq'd Cheyenne Light 1/05; utility ops. from Aquila 7/08; SourceGas 2/16. Discont. telecom in '05; oil marketing in '06; gas marketing in '11; gas & oil E&P in '17. Electric rev. breakdown: res'l, 30%; comm'l, 35%; ind'l, 18%; other, 17%. Generating sources: coal, 30%; other, 12%; purch., 58%. Fuel costs: 33% of revs. '19 deprec. rate: 3.2%. Has 2,900 employees. Chairman: David R. Emery. Pres. & CEO: Linn Evans. Inc.: SD. Address: 7001 Mount Rushmore Rd., P.O. Box 1400, Rapid City, SD 57709-1400. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills is awaiting a rate order in Colorado. The company filed for a gas rate increase of $2.5 million, based on a return on equity of 10.3% and a common-equity ratio of 50.1%. Black Hills also wants to consolidate its disparate rates in the state into one tariff. However, an administrative law judge recommended a $2 million rate *decrease*, based on an ROE of 9.5%. A ruling from the Colorado regulators might well come in the next few weeks. We don't know what the commission will do, but we note that Black Hills' most recent electric rate order in Colorado, in January of 2017, was unfavorable for the utility.

At least one other gas rate application is upcoming. Black Hills plans to file a case in Nebraska in mid-2020, but this might be delayed until later this year due to the disruption caused by the coronavirus situation. A petition in Arkansas might come in late 2020 or early 2021.

We have trimmed our 2020 share-earnings estimate by $0.10, to $3.55. This is the low end of Black Hills' targeted range of $3.55-$3.75. As of late March, Black Hills was not expecting a significant effect on ntility volume in the first quarter, but we think the weakening economy will eventnally reduce commercial electric volume.

We look for a solid profit increase next year. The economy should be in better shape. Also, even if Black Hills gets little or no benefit from upconing regulatory activity, we note that the company still obtains revenues annually from various cost-recovery mechanisms.

Black Hills sold some stock in February. Its timing was good, as the issuance occurred before the market plummeted. The company sold 1.2 million shares for $100 million, and used the proceeds to pay off commercial paper borrowings.

The company is building a wind project. This will add 52.5 megawatts of capacity at a cost of $79 million. This should be completed by yearend.

This stock has a high valuation for a utility. The dividend yield is a cut below the industry average. Total return potential doesn't stand out for the group, either for the 18-month span or the 3- to 5-year period.

Paul E. Debbas, CFA *April 24, 2020*

(A) Dil. EPS. Excl. nonrec. gains (losses): '08, ($1.55); '09, (28¢); '10, 10¢; '15, ($3.54); '16, ($1.26); '17, 14¢; '18, $1.31; '19, (25¢); gains (losses) on disc. ops.: '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢); '17, (31¢); '18, (12¢). '19 EPS don't sum due to rounding. Next egs. due early May. (B) Div'ds pd. early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '19: $25.06/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '15: none; in CO in '17: 9.37%; earn. on avg. com. eq., '19: 9.4%. Reg. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	70

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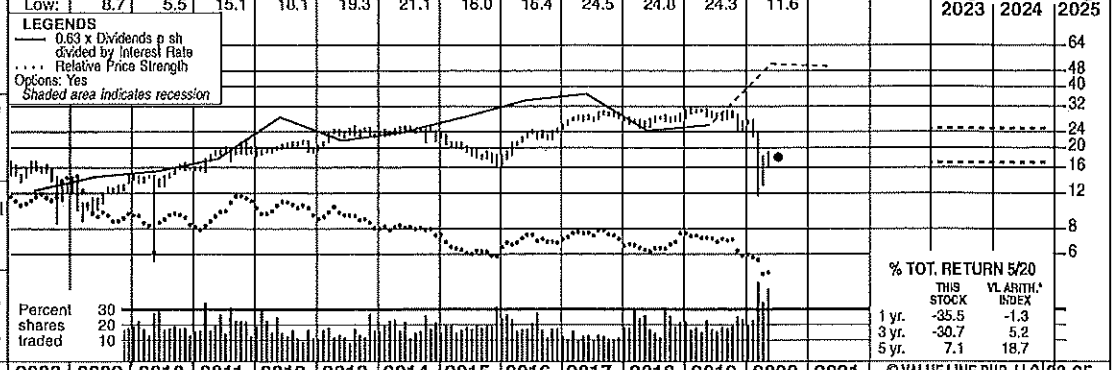
CENTERPOINT EN'RGY NYSE-CNP

RECENT PRICE 18.05 | P/E RATIO 13.4 (Trailing: 10.2 Median: 18.0) | RELATIVE P/E RATIO 0.68 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Lowered 5/29/20
SAFETY 3 Lowered 12/18/15
TECHNICAL 3 Raised 5/29/20
BETA 1.15 (1.00 = Market)

High:	14.9	17.0	21.5	21.8	25.7	25.8	23.7	25.0	30.5	29.6	31.4	27.5
Low:	8.7	5.5	15.1	10.1	19.3	21.1	16.0	16.4	24.5	24.0	24.3	11.6

LEGENDS
— 0.63 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$13-$34 $24 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+40%)	11%
Low	17	(-5%)	3%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	274	259	266
to Sell	307	305	293
Hld's(000)	402169	421555	413899

Percent shares traded 30 20 10

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-35.5	-1.3
3 yr.	-30.7	5.2
5 yr.	7.1	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
27.63	31.33	29.71	29.82	32.71	21.14	20.69	19.83	17.43	18.90	21.51	17.18	17.48	22.30	21.13	24.49	*13.05*	*13.60*	Revenues per sh	*12.50*
2.56	2.72	3.47	3.39	3.42	2.94	3.14	3.43	3.89	3.54	3.85	3.40	3.68	4.03	3.24	4.12	*3.55*	*3.80*	"Cash Flow" per sh	*4.00*
.61	.67	1.33	1.17	1.30	1.01	1.07	1.27	1.35	1.24	1.42	1.08	1.00	1.57	.74	1.49	*1.35*	*1.45*	Earnings per sh A	*1.65*
.40	.40	.60	.68	.73	.76	.76	.79	.81	.83	.95	.99	1.03	1.35	1.12	.86	*.74*	*.64*	Div'd Decl'd per sh B ■	*.80*
1.72	2.23	3.21	3.45	2.95	2.96	3.55	3.06	2.84	3.00	3.20	3.68	3.28	3.31	3.29	4.99	*4.75*	*4.85*	Cap'l Spending per sh	*4.25*
3.59	4.18	4.96	5.61	5.89	6.74	7.53	9.91	10.06	10.09	10.60	8.05	8.03	10.88	12.53	13.10	*11.20*	*12.10*	Book Value per sh C	*15.50*
308.05	310.33	313.65	322.72	346.09	391.75	424.70	426.03	427.44	429.00	429.00	430.00	430.68	431.04	501.20	502.24	*545.00*	*545.00*	Common Shs Outst'g D	*640.00*
17.8	19.1	10.3	15.0	11.3	11.8	13.8	14.6	14.8	18.7	17.0	18.1	21.9	17.9	NMF	19.5	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.94	1.02	.56	.80	.68	.79	.88	.92	.94	1.05	.89	.91	1.15	.90	NMF	1.04	*Value Line*		Relative P/E Ratio	*.70*
3.7%	3.1%	4.4%	3.9%	5.0%	6.4%	5.3%	4.3%	4.0%	3.6%	3.9%	5.1%	4.7%	4.6%	4.1%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $15256 mill. Due in 5 Yrs $8828 mill.
LT Debt $13830 mill. LT Interest $698 mill.
Incl. $710 mill. securitized transition & system restoration bonds.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $6 mill.
Pension Assets-12/19 $2005 mill. Oblig $2453 mill.
Pfd Stock $1778 mill. Pfd Div'd $117 mill.
800,000 shs. 6.125%, cum., 977,500 shs. 7%, cum., all with liquidation value of $1000.
Common Stock 502,656,951 shs. as of 5/1/20
MARKET CAP: $9.1 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
8785.0	8450.0	7452.0	8106.0	9226.0	7386.0	7528.0	9614.0	10589	12301	*7100*	*7400*	Revenues ($mill)	*8000*
442.0	546.0	581.0	536.0	611.0	465.0	432.0	679.0	368.0	871.0	*900*	*990*	Net Profit ($mill)	*1100*
37.3%	33.6%	33.4%	31.4%	31.0%	35.1%	37.0%	36.1%	28.4%	14.9%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
2.7%	1.6%	2.6%	3.5%	4.1%	4.7%	3.5%	2.9%	5.4%	6.7%	*7.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
73.8%	67.2%	66.0%	64.4%	63.8%	69.5%	68.5%	63.6%	51.9%	63.0%	*59.0%*	*58.5%*	Long-Term Debt Ratio	*57.0%*
26.2%	32.8%	34.0%	35.6%	36.2%	30.5%	31.5%	36.4%	37.5%	29.1%	*29.0%*	*30.5%*	Common Equity Ratio	*40.0%*
12199	12863	12658	12146	12557	11362	10992	12883	16740	22603	*20900*	*21725*	Total Capital ($mill)	*24700*
11732	12402	13597	9593.0	10502	11537	12307	13057	14044	20945	*22600*	*24225*	Net Plant ($mill)	*28700*
6.1%	6.4%	6.8%	6.3%	6.7%	6.1%	5.8%	6.8%	3.4%	5.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
13.8%	12.9%	13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	4.6%	10.4%	*10.5%*	*11.0%*	Return on Shr. Equity	*10.5%*
13.8%	12.9%	13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	5.3%	11.5%	*12.5%*	*12.5%*	Return on Com Equity E	*10.5%*
3.8%	5.0%	5.5%	4.2%	4.5%	1.1%	NMF	4.7%	NMF	2.7%	*6.0%*	*7.0%*	Retained to Com Eq	*5.5%*
72%	62%	60%	66%	67%	92%	103%	66%	NMF	80%	*60%*	*52%*	All Div'ds to Net Prof	*51%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+2.1	+2.0	+6.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.7	+1.7	+7.9
Fixed Charge Cov. (%)	269	167	152

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-2.0%	3.5%	*-9.5%*
"Cash Flow"	1.5%	--	*1.0%*
Earnings	1.0%	-1.0%	*4.5%*
Dividends	4.5%	5.0%	*-5.5%*
Book Value	7.0%	3.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2017	2735	2143	2098	2638	9614.0
2018	3155	2186	2212	3036	10589
2019	3531	2798	2742	3230	12301
2020	2167	*1500*	*1500*	*1933*	*7100*
2021	*2250*	*1550*	*1550*	*2050*	*7400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2017	.44	.31	.39	.43	1.57
2018	.38	d.17	.35	.18	.74
2019	.28	.33	.47	.41	1.49
2020	.56	*.25*	*.34*	*.20*	*1.35*
2021	*.50*	*.30*	*.40*	*.25*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.2575	.2575	.2575	.2575	1.03
2017	.2675	.2675	.2675	.2675	1.07
2018	.2775	.2775	.2775	.2775	1.11
2019	.2875	.2875	.2875	.2875	1.15
2020	.29	.15			

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.5 million customers in Houston and environs, Indiana Electric, which serves 148,000 customers, and gas utilities with 4.6 million customers in Texas, Minnesota, Arkansas, Louisiana, Oklahoma, Indiana, and Ohio. Owns 53.7% of Enable Midstream Partners. Has nonutility operations that are in the process of being sold. Acquired Vectren 2/19. Electric revenue breakdown not available. Fuel costs: 46% of revenues. '19 depreciation rate: 4.3%. Has 14,300 employees. Chairman: Milton Carroll. Interim President & CEO: John W. Somerhalder II. Inc.: TX. Address: 1111 Louisiana, P.O. Box 4567, Houston, TX 77210-4567. Tel.: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy has received a significant equity infusion. Various investors purchased $675 million of common stock and $725 million of mandatorily convertible preferred stock. The company expects this to cover its expected equity needs through 2022. Two board members were added, and will be part of a five-man committee that will make recommendations to the board of directors by October.

The stock reacted favorably to the news. The price rose more than 10% on the day of the announcement. Even so, the quotation is down 34% so far this year—much more than most utility issues. A sizable decline in the value of CenterPoint's 53.7% stake in Enable Midstream Partners, a natural gas master limited partnership, is reflected in the quotation. In fact, in the first quarter CenterPoint took a $1.2 billion aftertax charge to write down its stake in Enable and a separate $185 million goodwill writedown at Vectren, which it bonght in early 2019. The equity is also feeling the effects of a harsh rate order at Houston Electric and a cut in the quarterly dividend from $0.29 a share to $0.15. Note that CenterPoint is operating with interim chief executive and chief financial officers.

Two asset sales were completed in the second quarter. CenterPoint sold its infrastructure services business for aftertax proceeds of $670 million. The sale of its energy services operation brought iu $286 million, nearly $100 million less than previously expected due to changes in commodity prices. The cash is being used for debt retirement. These are accounted for as discontinued operations. The sales will be modestly dilutive to earnings.

In light of everything mentioned above, the direct effects of the weak economy aren't a big investment consideration. CenterPoint will defer for future recovery most (if not all) of its coronavirus-related costs. However, the company estimates the reduction in commercial and industrial kilowatt-hour sales will hurt share net by $0.05-$0.08 in 2020.

The untimely stock is of little interest to near-term investors. The dividend yield is a cut below the utility mean. There is some appeal for the 18-month span, but not so much for the 3- to 5-year period.

Paul E. Debbas, CFA *June 12, 2020*

(A) Diluted EPS. Excl. extraord. gains (losses): '04, ($2.72); '05, 9¢; '11, $1.89; '12, (38¢); '13, (52¢); '15, ($2.69); '17, $2.56; '20, $2.71; losses on disc. ops.: '04, 37¢; '05, 1¢; '20, 29¢. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept. & Dec. 5 declarations in '17, 3 in '19. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '19: $15.14/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. (elec.) in '20: 9.4%; (gas): 9.45%-11.25%; earned on avg. com. eq., '19: 11.6%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	75
Price Growth Persistence	35
Earnings Predictability	45

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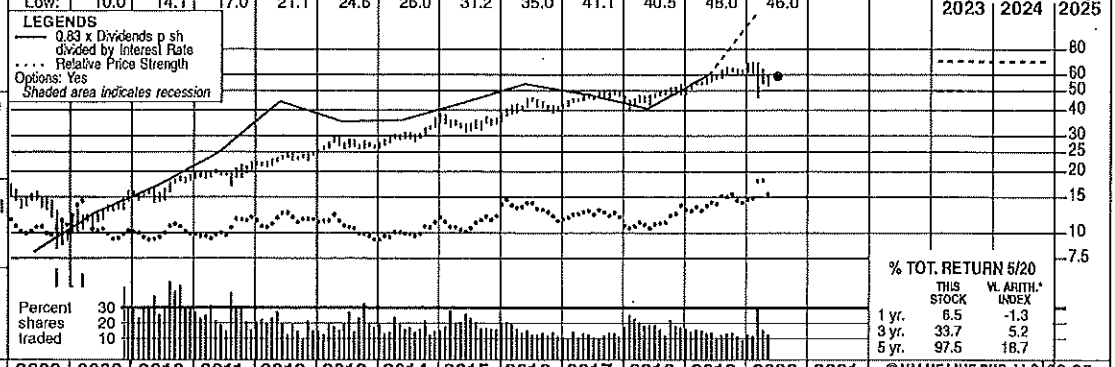
CMS ENERGY CORP. NYSE-CMS

RECENT PRICE 59.01 | P/E RATIO 22.7 (Trailing: 23.7 Median: 18.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 1/11/19
SAFETY 2 Raised 3/21/14
TECHNICAL 2 Lowered 5/12/20
BETA .80 (1.00 = Market)

High:	16.1	19.3	22.4	25.0	30.0	36.9	38.7	46.3	50.8	53.8	65.3	69.2
Low:	10.0	14.1	17.0	21.1	24.6	26.0	31.2	35.0	41.1	40.5	48.0	46.0

LEGENDS
— 0.83 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$46-$99	$73 (25%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+20%)	7%
Low	50	(-15%)	Nil

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	253	295	252
to Sell	269	247	301
Hld's(000)	263460	264207	265297

Percent shares traded 30 20 10

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.5	-1.3
3 yr.	33.7	5.2
5 yr.	97.5	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
28.06	28.52	30.57	28.95	30.13	27.23	25.77	25.59	23.90	24.68	26.09	23.29	22.92	23.37	24.25	24.11	*21.60*	*22.40*	Revenues per sh	*24.25*
2.87	3.43	3.22	3.08	3.88	3.47	3.70	3.65	3.82	4.06	4.22	4.59	4.88	5.29	5.61	5.69	*6.25*	*6.55*	"Cash Flow" per sh	*7.75*
.74	1.10	.64	.64	1.23	.93	1.33	1.45	1.53	1.66	1.74	1.89	1.98	2.17	2.32	2.39	*2.60*	*2.75*	Earnings per sh A	*3.50*
--	--	--	.20	.36	.50	.66	.84	.96	1.02	1.08	1.16	1.24	1.33	1.43	1.53	*1.63*	*1.74*	Div'd Decl'd per sh B ■	*2.15*
2.69	2.69	3.01	5.61	3.50	3.59	3.29	3.47	4.65	4.98	5.73	5.64	5.99	5.91	7.32	7.41	*7.65*	*9.30*	Cap'l Spending per sh	*8.00*
10.63	10.53	10.03	9.46	10.88	11.42	11.19	11.92	12.09	12.98	13.34	14.21	15.23	15.77	16.78	17.68	*19.35*	*20.70*	Book Value per sh C	*25.50*
195.00	220.50	222.78	225.15	226.41	227.89	249.60	254.10	264.10	266.10	275.20	277.16	279.21	281.65	283.37	283.86	*287.00*	*290.00*	Common Shs Outst'g D	*300.00*
12.4	12.6	22.2	26.8	10.9	13.6	12.5	13.6	15.1	16.3	17.3	18.3	20.9	21.3	20.3	24.3	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.66	.67	1.20	1.42	.66	.91	.80	.85	.96	.92	.91	.92	1.10	1.07	1.10	1.30	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	1.2%	2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	3.6%	3.4%	3.0%	2.9%	3.0%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $14337 mill. Due in 5 Yrs $4549 mill.
LT Debt $12616 mill. LT Interest $544 mill.
Incl. $71 mill. capitalized leases.
(LT interest earned: 2.6x)
Leases, Uncapitalized Annual rentals $11 mill.
Pension Assets-12/19 $2546 mill. Oblig $2973 mill.
Pfd Stock $37 mill. Pfd Div'd $2 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00.
Common Stock 286,221,472 shs. as of 4/6/20
MARKET CAP: $17 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
6432.0	6503.0	6312.0	6566.0	7179.0	6456.0	6399.0	6583.0	6873.0	6845.0	*6200*	*6500*	Revenues ($mill)	*7250*
356.0	384.0	413.0	454.0	479.0	525.0	553.0	610.0	659.0	682.0	*755*	*805*	Net Profit ($mill)	*1045*
38.1%	36.8%	39.4%	39.9%	34.3%	34.0%	33.1%	31.2%	14.9%	17.7%	*16.0%*	*16.0%*	Income Tax Rate	*16.0%*
2.2%	2.6%	2.9%	2.0%	2.3%	2.7%	3.1%	1.1%	1.4%	2.1%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
70.1%	66.9%	67.9%	67.5%	68.7%	68.3%	67.1%	67.3%	69.0%	70.4%	*70.5%*	*70.0%*	Long-Term Debt Ratio	*68.5%*
29.5%	32.6%	31.6%	32.2%	31.0%	31.4%	32.6%	32.4%	30.7%	29.4%	*29.5%*	*30.0%*	Common Equity Ratio	*31.5%*
9473.0	9279.0	10101	10730	11846	12534	13040	13692	15476	17082	*19000*	*20150*	Total Capital ($mill)	*24200*
10069	10633	11551	12246	13412	14705	15715	16761	18126	18926	*20075*	*21675*	Net Plant ($mill)	*25200*
5.8%	6.3%	5.9%	6.0%	5.7%	5.7%	5.8%	5.9%	5.6%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
12.5%	12.5%	12.8%	13.0%	12.9%	13.2%	12.9%	13.6%	13.8%	13.5%	*13.5%*	*13.5%*	Return on Shr. Equity	*13.5%*
12.5%	12.6%	12.9%	13.1%	13.0%	13.3%	13.0%	13.7%	13.8%	13.6%	*13.5%*	*13.5%*	Return on Com Equity E	*13.5%*
6.9%	5.6%	5.0%	5.2%	5.0%	5.2%	4.8%	5.2%	5.3%	4.9%	*5.0%*	*5.0%*	Retained to Com Eq	*5.5%*
46%	55%	61%	60%	62%	61%	63%	62%	62%	64%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-1.4	+2.2	-3.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.26	7.63	7.94
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	7634	8084	8039
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+.3	+.9
Fixed Charge Cov. (%)	301	250	235

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-2.0%	-1.0%	*Nil*
"Cash Flow"	5.0%	7.0%	*5.5%*
Earnings	9.5%	7.0%	*7.5%*
Dividends	15.0%	7.0%	*7.0%*
Book Value	4.5%	5.5%	*7.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1829	1449	1527	1778	6583.0
2018	1953	1492	1599	1829	6873.0
2019	2059	1445	1546	1795	6845.0
2020	1864	*1300*	*1400*	*1636*	*6200*
2021	*1950*	*1400*	*1450*	*1700*	*6500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.71	.33	.61	.52	2.17
2018	.86	.49	.59	.38	2.32
2019	.75	.33	.73	.58	2.39
2020	.85	*.50*	*.75*	*.50*	*2.60*
2021	*.85*	*.55*	*.80*	*.55*	*2.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.31	.31	.31	.31	1.24
2017	.3325	.3325	.3325	.3325	1.33
2018	.3575	.3575	.3575	.3575	1.43
2019	.3825	.3825	.3825	.3825	1.53
2020	.4075	.4075			

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.8 million gas customers. Has 1,234 megawatts of nonregulated generating capacity. Owns EnerBank. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 45%; commercial, 34%; industrial, 15%; other, 6%. Generating sources: coal, 27%; gas, 18%; other, 3%; purchased, 52%. Fuel costs: 41% of revenues. '19 reported deprec. rates: 3.9% electric, 2.9% gas, 10.0% other. Has 8,100 full-time employees. Chairman: John G. Russell. President & CEO: Patricia K. Poppe. Inc.: MI. Address: One Energy Plaza, Jackson, MI 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary has gas and electric rate cases pending. Consumers Energy filed for a gas increase of $245 million, based on a 10.5% return on equity. The application includes a request for a regulatory mechanism to decouple revenues and volume. The staff of the Michigan Public Service Commission (MPSC) is recommending a hike of $160 million, based on a 9.6% ROE. A settlement is possible. A ruling from the MPSC is due by October 16th. Consumers Energy is seeking an electric increase of $244 million, based on a 10.5% ROE. The MPSC's staff is expected to put forth its proposal on June 24th. An order is due by December 28th. The utility files rate applications frequently because it has a large system with a lot of old equipment.

We are sticking with our 2020 earnings estimate of $2.60 a share, but trimmed our 2021 estimate by $0.05 a share. This is slightly below CMS Energy's targeted range of $2.64-$2.68 because we include certain expenses (such as $15 million for employee retention at the Karn coal-fired plant, which will be retired in a few years) that management excludes from its guidance. Although the weak economy will hurt kilowatt-hour sales, parts of Consumers Energy's service area began to reopen in May. Also, the company has the flexibility to adjust operating and maintenance expenses to compensate for the lost volume. However, we are being more cautious in our 2021 expectation. The improvement we now estimate for 2021 would result in profit growth at the low end of CMS Energy's yearly goal of 6%-8%. The stock price has declined 6% in 2020, making this equity an above-average performer among utilities.

The company has made a lot of financing moves this year. CMS Energy or its utility subsidiary have issued over $1 billion of long-term debt, $500 million of equity units that are convertible into common equity, and $100 million of common stock. The company expects to issue a total of $250 million of common equity in 2020.

CMS Energy stock has a low dividend yield for a utility. This is about a percentage point below the industry mean. Total return potential is attractive for the 18-month span, but not for 2023-2025.

Paul E. Debbas, CFA *June 12, 2020*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); '17, (53¢); gains (losses) on discont. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢. Next earnings report due late July. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '19: $8.77/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '18: 10% elec.; in '19: 9.9% gas; earned on avg. com. eq., '19: 13.9%. Regulat. Climate: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	75
Earnings Predictability	85

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CON. EDISON NYSE-ED

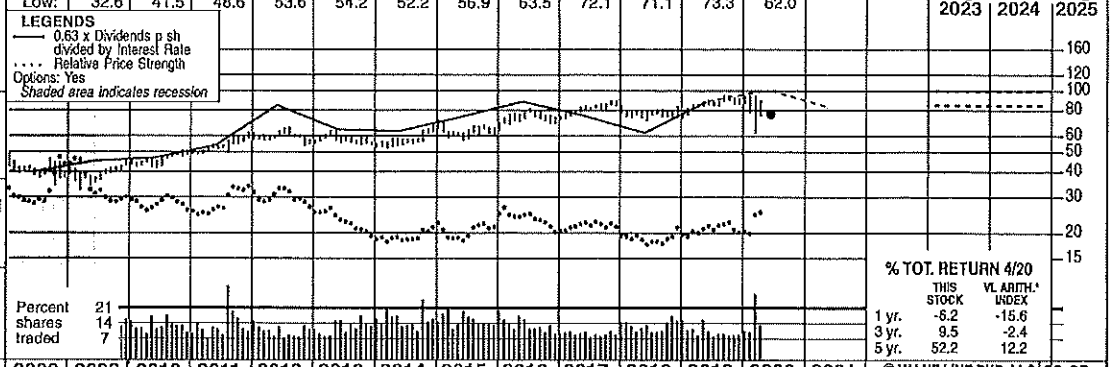
RECENT PRICE 77.06 | P/E RATIO 18.1 (Trailing: 18.9 Median: 16.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Lowered 3/8/19
SAFETY 1 New 7/27/90
TECHNICAL 2 Raised 5/1/20
BETA .75 (1.00 = Market)

High:	46.3	51.0	62.7	66.0	64.0	68.9	72.3	81.9	89.7	84.9	95.0	95.1
Low:	32.6	41.5	48.6	53.6	54.2	52.2	56.9	63.5	72.1	71.1	73.3	62.0

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.63 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$73-$103	$88 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+30%)	10%
Low	85	(+10%)	7%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	401	408	413
to Sell	347	342	368
Hld's(000)	199915	200721	200729

Percent shares traded 21 14 7

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.2	-15.6
3 yr.	9.5	-2.4
5 yr.	52.2	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.59	38.82	38.43	37.76	*36.15*	*36.45*	Revenues per sh	*38.25*
4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.89	8.41	8.92	9.09	*9.20*	*9.70*	"Cash Flow" per sh	*11.00*
2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.94	4.10	4.55	4.68	*4.25*	*4.55*	Earnings per sh A	*5.00*
2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	2.76	2.86	2.96	*3.06*	*3.16*	Div'd Decl'd per sh B ■	*3.50*
5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	8.26	10.42	12.07	11.11	10.89	10.47	*11.50*	*11.20*	Cap'l Spending per sh	*11.00*
29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.88	49.74	52.11	54.12	*55.75*	*57.60*	Book Value per sh C	*62.75*
242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	292.88	293.00	305.00	310.00	321.00	333.00	*343.00*	*351.00*	Common Shs Outst'g D	*365.00*
18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	19.8	17.1	21.1	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
.96	.80	.84	.73	.74	.83	.85	.95	.98	.83	.84	.79	.99	1.00	.92	1.13	*Value Line*		Relative P/E Ratio	*1.05*
5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	4.1%	3.6%	3.4%	3.7%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $21665 mill. Due in 5 Yrs $6243 mill.
LT Debt $18527 mill. LT Interest $835 mill.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $78 mill.

Pension Assets-12/19 $15608 mill. Oblig $16792 mill.

Pfd Stock None

Common Stock 333,775,472 shs. as of 1/31/20

MARKET CAP: $26 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
13325	12938	12168	12381	12919	12554	12075	12033	12337	12574	*12400*	*12800*	Revenues ($mill)	*14000*
992.0	1062.0	1141.0	1157.0	1066.0	1193.0	1189.0	1266.0	1424.0	1343.0	*1440*	*1580*	Net Profit ($mill)	*1825*
36.0%	36.1%	34.5%	31.8%	34.0%	33.6%	35.3%	36.6%	20.1%	17.1%	*19.5%*	*17.0%*	Income Tax Rate	*17.0%*
2.4%	1.6%	.5%	.5%	.3%	.7%	1.3%	1.5%	1.5%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
48.6%	46.5%	45.9%	46.1%	48.0%	47.9%	50.8%	48.9%	51.1%	50.7%	*49.5%*	*49.5%*	Long-Term Debt Ratio	*49.5%*
50.4%	52.5%	54.1%	53.9%	52.0%	52.1%	49.2%	51.1%	48.9%	49.3%	*50.5%*	*50.5%*	Common Equity Ratio	*50.5%*
21952	21794	21933	22735	24207	25058	29033	30149	34221	36549	*37675*	*40250*	Total Capital ($mill)	*45600*
23863	25093	26939	28436	29827	32209	35216	37600	41749	43889	*46125*	*48225*	Net Plant ($mill)	*53800*
5.9%	6.2%	6.5%	6.4%	5.6%	6.0%	5.3%	5.4%	5.3%	4.9%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
8.8%	9.1%	9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	7.5%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.0%*
8.9%	9.2%	9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	7.5%	*7.5%*	*8.0%*	Return on Com Equity E	*8.0%*
3.2%	3.1%	3.6%	3.6%	2.6%	3.5%	3.0%	3.0%	3.5%	2.3%	*2.0%*	*2.5%*	Retained to Com Eq	*2.5%*
65%	66%	62%	62%	69%	61%	64%	63%	59%	69%	*67%*	*65%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.8	+2.8	-2.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	13731	14156	13835
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	354	306	267

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-2.0%	-2.0%	*Nil*
"Cash Flow"	4.0%	4.0%	*4.0%*
Earnings	2.5%	2.0%	*3.0%*
Dividends	2.0%	3.0%	*3.5%*
Book Value	4.0%	4.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	3228	2633	3211	2961	12033
2018	3364	2696	3328	2949	12337
2019	3514	2744	3365	2951	12574
2020	*3400*	*2700*	*3350*	*2950*	*12400*
2021	*3550*	*2800*	*3450*	*3000*	*12800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.27	.57	1.48	.78	4.10
2018	1.37	.60	1.52	1.06	4.55
2019	1.31	.46	1.42	.88	4.08
2020	*1.35*	*.60*	*1.50*	*.80*	*4.25*
2021	*1.45*	*.65*	*1.60*	*.85*	*4.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.67	.67	.67	.67	2.68
2017	.69	.69	.69	.69	2.76
2018	.715	.715	.715	.715	2.86
2019	.74	.74	.74	.74	2.96
2020	.765				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. Has 3.7 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Entered into midstream gas joint venture 6/16. Purchases most of its power. Fuel costs: 21% of revenues. '19 reported depreciation rates: 3.0%-3.2%. Has 14,900 employees. Chairman, President & CEO: John McAvoy. Inc.: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

We estimate that Consolidated Edison's earnings will advance in 2020 and 2021. The company's largest utility subsidiary, Consolidated Edison Company of New York, was granted rate relief for each year from 2020 through 2022. Electric and gas rates rose $113 million and $84 million, respectively, effective at the start of 2020. Electric tariffs will increase $370 million in 2021 and $326 million in 2022. Gas rates will rise $122 million in 2021 and $167 million in 2022. The utility will benefit from regulatory mechanisms that will enable it to recover annual increases in certain expense items. In addition, ConEd's Rockland Electric subsidiary received a $12 million rate hike at the start of February. However . . .

We have lowered our 2020 and 2021 earnings estimates by $0.15 a share each year. ConEd's financing costs (both debt and equity) will probably be greater than we had expected in our mid-February report. Our 2020 estimate of $4.25 a share is slightly below the company's targeted range of $4.30-$4.50 because ConEd excludes an accounting charge of $0.19 a share related to its renewable-energy business. (Such a charge reduced the bottom line by $0.22 a share in 2019.) Using the company's 2020 guidance as a base, ConEd's five-year forecast of earnings growth is 3%-5% annually.

The coronavirus pandemic has affected ConEd. Some employees have died, and numerous others have had to miss work. The company is incurring expenses stemming from this problem, but any fall in kilowatt-hour sales won't have much effect on income because most of the utility's business operates under a mechanism that decouples revenues and volume.

The renewable-energy operation is adding projects. As of year-end 2019, the company had 2.682 megawatts operating and 419 mw under construction. This subsidiary now produces less than 10% of corporate profits, but this proportion is likely to rise in the coming years.

The stock's dividend yield is about average for a utility. The stock price has declined 15% this year, in line with many utilities. Total return potential is unspectacular for the 18-month and 3- to 5-year periods.

Paul E. Debbas, CFA *May 15, 2020*

(A) Diluted EPS. Excl. nonrec. gains (losses): '13, (32¢); '14, 9¢; '16, 15¢; '17, 84¢; '18, (13¢); gain on discontinued operations: '08, $1.01. '19 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '19: $21.01/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '20: 6.8%; O&R in '19: 9.0%; earned on avg. com. eq., '19: 8.2%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	95

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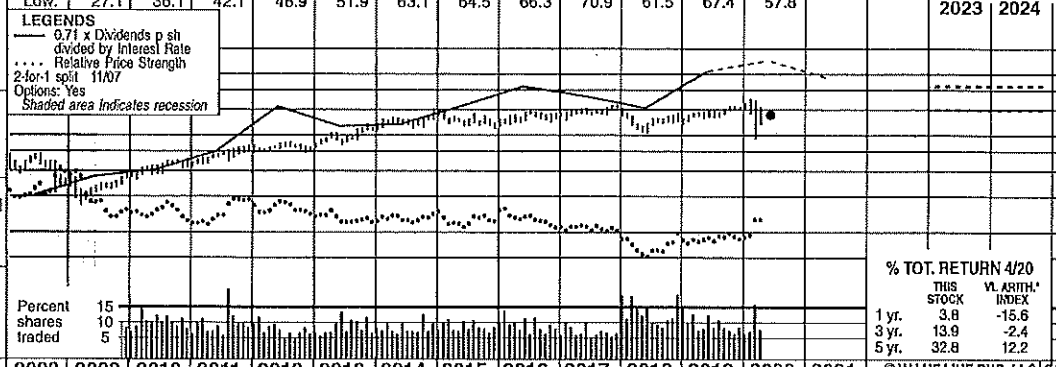
DOMINION ENERGY NYSE-D

RECENT PRICE 75.80 | P/E RATIO 23.0 (Trailing: 25.9 Median: 21.0) | RELATIVE P/E RATIO 1.39 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 2 Lowered 5/1/20
SAFETY 2 Raised 9/11/98
TECHNICAL 2 Raised 4/17/20
BETA .80 (1.00 = Market)

High:	39.8	45.1	53.6	55.6	68.0	80.9	79.9	79.0	65.3	81.7	83.9	90.9
Low:	27.1	36.1	42.1	48.9	51.9	63.1	64.5	66.3	70.9	61.5	67.4	57.8

Target Price Range 2023 | 2024 | 2025



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$60-$132	$96 (25%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+40%)	12%
Low	80	(+5%)	6%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	653	712	739
to Sell	492	460	545
Hld's(000)	529909	544967	565133

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.8	-15.6
3 yr.	13.9	-2.4
5 yr.	32.8	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
20.54	25.96	23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.25	19.59	18.70	19.53	19.63	19.78	*20.20*	*20.90*	Revenues per sh	*22.50*
4.18	3.70	4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.71	5.98	6.33	6.90	6.48	5.73	*7.00*	*8.15*	"Cash Flow" per sh	*9.75*
2.13	1.50	2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	3.53	3.25	2.19	*3.30*	*4.30*	Earnings per sh A	*5.50*
1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	3.04	3.34	3.67	*3.76*	*3.86*	Div'd Decl'd per sh B ■	*4.15*
3.88	4.83	5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.13	9.35	9.69	8.54	6.25	5.94	*9.50*	*9.45*	Cap'l Spending per sh	*9.00*
16.79	14.96	18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	19.74	21.24	23.26	26.59	29.53	35.33	*34.45*	*35.05*	Book Value per sh C	*39.75*
680.40	695.00	698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	585.30	596.30	627.80	644.60	680.90	838.00	*842.00*	*846.00*	Common Shs Outst'g D	*880.00*
15.1	24.9	16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23.0	22.1	21.3	22.2	21.8	NMF	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.80	1.33	.88	1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12	1.12	1.18	NMF	*Value Line*		Relative P/E Ratio	*.95*
4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%	3.7%	3.8%	3.9%	4.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $39724 mill. Due in 5 Yrs $14892 mill.
LT Debt $34615 mill. LT Interest $1450 mill.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $72 mill.

Pension Assets-12/19 $9631 mill. Oblig $10446 mill.
Pfd Stock $2387 mill. Pfd Divd $65 mill.
2 mill. shs. 1.75%, cum., convert. in 2022. 800,000 shs. 4.65%, cum., redeemable not before 12/15/24.
Common Stock 839,251,000 shs. as of 4/17/20
MARKET CAP: $64 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
15197	14379	13093	13120	12436	11683	11737	12586	13366	16572	*17000*	*17700*	Revenues ($mill)	*19800*
1724.0	1603.0	1594.0	1806.0	1793.0	1899.0	2123.0	2244.0	2130.0	1838.0	*2870*	*3700*	Net Profit ($mill)	*4900*
38.6%	34.6%	36.2%	33.0%	28.1%	32.0%	22.8%	27.2%	17.7%	21.8%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
5.9%	5.3%	5.7%	3.7%	4.5%	5.3%	7.5%	10.5%	6.3%	4.8%	*3.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
56.3%	59.8%	60.9%	61.9%	65.4%	65.1%	67.4%	64.4%	60.8%	51.4%	*52.5%*	*53.5%*	Long-Term Debt Ratio	*53.0%*
42.8%	39.3%	38.2%	37.3%	34.6%	34.9%	32.6%	35.6%	39.2%	45.0%	*43.5%*	*43.0%*	Common Equity Ratio	*46.0%*
28012	29097	27676	31229	33360	36280	44836	48090	51251	65818	*66325*	*68925*	Total Capital ($mill)	*75900*
26713	29670	30773	32628	36270	41554	49964	53758	54560	69082	*73975*	*78725*	Net Plant ($mill)	*92100*
7.7%	7.0%	7.5%	7.3%	6.6%	6.5%	6.0%	5.9%	5.5%	4.0%	*5.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
14.1%	13.7%	14.7%	15.2%	15.5%	15.0%	14.5%	13.1%	10.6%	5.7%	*9.0%*	*11.5%*	Return on Shr. Equity	*13.5%*
14.2%	13.9%	14.9%	15.4%	15.4%	15.0%	14.5%	13.1%	10.6%	6.2%	*9.5%*	*12.0%*	Return on Com Equity E	*14.0%*
5.3%	4.0%	3.5%	4.2%	3.3%	2.9%	2.7%	1.8%	NMF	NMF	*NMF*	*1.5%*	Retained to Com Eq	*3.5%*
63%	71%	77%	73%	79%	81%	81%	86%	103%	NMF	*NMF*	*92%*	All Div'ds to Net Prof	*76%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	287	219	166

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-3.0%	-2.5%	*2.0%*
"Cash Flow"	2.5%	3.0%	*6.0%*
Earnings	1.5%	--	*7.0%*
Dividends	7.5%	8.0%	*4.5%*
Book Value	6.0%	9.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	3384	2813	3179	3210	12586
2018	3466	3088	3451	3361	13366
2019	3858	3970	4269	4475	16572
2020	4496	*3904*	*4200*	*4400*	*17000*
2021	*4600*	*4100*	*4400*	*4600*	*17700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.01	.62	1.03	.87	3.53
2018	.77	.82	1.22	.44	3.25
2019	d.37	.13	1.23	1.22	2.19
2020	.35	*.80*	*1.05*	*1.10*	*3.30*
2021	*1.15*	*.85*	*1.15*	*1.15*	*4.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.70	.70	.70	.70	2.80
2017	.755	.755	.755	.77	3.04
2018	.835	.835	.835	.835	3.34
2019	.9175	.9175	.9175	.9175	3.67
2020	.94				

BUSINESS: Dominion Energy, Inc. (formerly Dominion Resources) is a holding company for Virginia Power, North Carolina Power, & South Carolina E&G, which serve 3.4 mill. customers in VA, SC, & NC. Serves 3.4 mill. gas customers in OH, WV, UT, SC, & NC. Other ops. incl. independent power production. Acq'd Questar 9/16; SCANA 1/19. Elec. rev. breakdown: residential, 46%; commercial, 32%; industrial, 7%; other, 15%. Generating sources: gas, 41%; nuclear, 29%; coal, 8%; other, 5%; purchased, 17%. Fuel costs: 28% of revs. '19 reported deprec. rates: 2.4%-4.6%. Has 19,100 empls. Chairman, President & CEO: Thomas F. Farrell II. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dominionenergy.com.

We have cut our 2020 earnings estimate for Dominion Energy materially. First-quarter profits returned to the black, but were well below our expectation due to unrealized losses on the company's nuclear decommissioning trusts, which stemmed from the poor stock-market performance in the period. Unfavorable weather patterns hurt, too. As a result, we slashed our 2020 share-earnings estimate by $1.10, to $3.30. (We excluded an aftertax charge of $591 million for plant retirements.) Kilowatt-hour sales by the company's electric utilities will also be affected by the weak economy. Virginia Power does benefit from getting about 30% of its commercial load from data centers, which are still operating.

We expect earnings to be much improved in 2021. We figure the March-quarter tally will not be depressed, and the company's utilities will benefit from a stronger economy. South Carolina Electric & Gas plans to file a rate case this summer, with new tariffs taking effect in 2021. Even so, we lowered our estimate by $0.35 a share, to $4.30.

Dominion Energy is paying $175 million to Southern Company for some midstream gas assets. These include transportation and storage and Southern Company's 5% stake in a gas-pipeline project under construction. The company will own 53% of the pipeline. Litigation has delayed the project and caused significant cost overruns. The latest cost estimate is $8.0 billion, up from $7.3 billion-$7.8 billion previously.

This timely stock has a dividend yield that is more than one percentage point above the utility average. However, dividend growth potential from now through 2023-2025 is 2.5% annually, about half of the norm for the group. Total return potential is respectable for the 18-month span but unspectacular for the 3- to 5-year period. Investors should note that the company's SCANA subsidiary is the subject of an SEC complaint about statements its executives made about a canceled nuclear construction project before Dominion Energy acquired SCANA in January of 2019. This does not appear to be affecting the share price much, for now. The quotation has declined 8% this year, less than most utility equities.

Paul E. Debbas, CFA *May 15, 2020*

(A) Dil. egs. Excl. nonrec. gains (losses): '07, $1.67; '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); '17, $1.19; '18, 43¢; '19, (58¢); '20, (67¢); losses from disc. ops.: '06, 26¢; '10, 26¢; '12, 4¢; '13, 16¢. '19 EPS don't sum due to chng. in shs. Next egs. report due early Aug. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $20.79/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '11: 10.9%; earned on avg. com. eq., '19: 6.7%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	50

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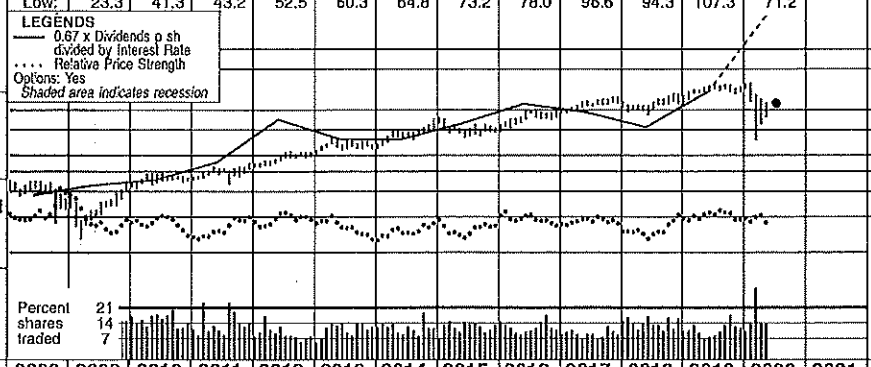
DTE ENERGY CO. NYSE-DTE

RECENT PRICE 108.42 | P/E RATIO 16.7 (Trailing: 18.4 Median: 17.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Lowered 6/14/19
SAFETY 2 Raised 12/21/12
TECHNICAL 4 Lowered 6/12/20
BETA .90 (1.00 = Market)

High:	45.0	49.1	55.3	62.6	73.3	90.8	92.3	100.4	116.7	121.0	134.4	135.7
Low:	23.3	41.3	43.2	52.5	60.3	64.8	73.2	78.0	96.6	94.3	107.3	71.2

LEGENDS
—— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$78-$175 $127 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	155	(+45%)	13%
Low	115	(+5%)	6%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	303	355	279
to Sell	264	245	345
Hld's(000)	133730	140654	140354

Percent shares traded 21 14 7

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.4	-1.3
3 yr.	8.2	5.2
5 yr.	60.2	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
40.84	50.74	50.93	54.28	57.23	48.45	50.51	52.57	51.01	54.56	69.50	57.60	59.24	70.28	78.12	65.91	*62.20*	*64.60*	Revenues per sh	*70.25*
6.81	8.14	8.19	8.48	8.26	9.38	9.78	9.57	9.77	10.13	11.85	9.44	10.60	11.77	12.58	12.97	*14.35*	*15.15*	"Cash Flow" per sh	*17.50*
2.55	3.27	2.45	2.66	2.73	3.24	3.74	3.67	3.88	3.76	5.10	4.44	4.83	5.73	6.17	6.31	*6.50*	*6.90*	Earnings per sh A	*8.25*
2.06	2.06	2.08	2.12	2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.84	3.06	3.36	3.59	3.85	*4.12*	*4.42*	Div'd Decl'd per sh B ■	*5.20*
5.19	5.99	7.92	7.96	8.42	6.26	6.49	8.77	10.56	10.59	11.58	11.26	11.40	12.54	14.91	15.59	*20.75*	*18.45*	Cap'l Spending per sh	*12.75*
31.85	32.44	33.02	35.86	36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	53.03	56.27	60.73	*63.35*	*66.50*	Book Value per sh C	*77.75*
174.21	177.81	177.14	163.23	163.02	165.40	169.43	169.25	172.35	177.09	176.99	179.47	179.43	179.39	181.93	192.21	*193.00*	*195.00*	Common Shs Outst'g D	*205.00*
16.0	13.8	17.4	18.3	14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19.0	18.6	17.4	19.9	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.85	.73	.94	.97	.89	.69	.78	.85	.95	1.01	.78	.91	1.00	.94	.94	1.06	*Value Line*		Relative P/E Ratio	*.90*
5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	3.5%	3.5%	3.3%	3.2%	3.3%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $18544 mill. Due in 5 Yrs $7604 mill.
LT Debt $17026 mill. LT Interest $661 mill.

(LT interest earned: 3.0x)

Leases, Uncapitalized Annual rentals $38 mill.

Pension Assets-12/19 $4993 mill. Oblig $5810 mill.

Pfd Stock None
Common Stock 192,611,882 shs.

MARKET CAP: $21 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
8557.0	8897.0	8791.0	9661.0	12301	10337	10630	12607	14212	12669	*12000*	*12600*	Revenues ($mill)	*14400*
630.0	624.0	666.0	661.0	905.0	796.0	868.0	1029.0	1120.0	1169.0	*1250*	*1340*	Net Profit ($mill)	*1685*
32.7%	35.9%	29.8%	27.5%	28.5%	25.6%	24.5%	21.8%	8.1%	11.5%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
1.6%	1.6%	3.0%	3.5%	4.1%	4.3%	3.6%	3.5%	3.8%	3.3%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
51.3%	50.6%	48.8%	47.7%	50.0%	50.2%	55.6%	56.2%	54.2%	57.7%	*60.0%*	*59.5%*	Long-Term Debt Ratio	*58.5%*
48.7%	49.4%	51.2%	52.3%	50.0%	49.8%	44.4%	43.8%	45.8%	42.3%	*40.0%*	*40.5%*	Common Equity Ratio	*41.5%*
13811	14196	14387	15135	16670	17607	20280	21697	22371	27607	*30400*	*32125*	Total Capital ($mill)	*38400*
12992	13746	14684	15800	16820	18034	19730	20721	21650	25317	*27800*	*29800*	Net Plant ($mill)	*32600*
6.3%	5.9%	6.1%	5.7%	6.6%	5.7%	5.3%	5.9%	6.1%	5.3%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	*10.0%*	*10.5%*	Return on Shr. Equity	*10.5%*
9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	*10.0%*	*10.5%*	Return on Com Equity E	*10.5%*
4.0%	3.4%	3.5%	2.7%	5.2%	3.4%	3.7%	4.6%	4.9%	4.1%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
57%	62%	61%	67%	52%	63%	61%	58%	55%	59%	*63%*	*64%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-3.1	+3.5	-3.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	300	278	260

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	3.0%	4.0%	*-.5%*
"Cash Flow"	3.5%	3.5%	*6.0%*
Earnings	8.0%	7.5%	*5.0%*
Dividends	5.5%	7.0%	*6.5%*
Book Value	4.5%	5.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	3236	2855	3245	3271	12607
2018	3753	3159	3550	3750	14212
2019	3514	2888	3119	3148	12669
2020	3022	*2778*	*2950*	*3250*	*12000*
2021	*3300*	*2900*	*3050*	*3350*	*12600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2.23	.99	1.51	1.00	5.73
2018	2.00	1.29	1.84	1.05	6.17
2019	2.19	.99	1.73	1.40	6.31
2020	1.76	*1.24*	*2.00*	*1.50*	*6.50*
2021	*2.00*	*1.30*	*2.10*	*1.50*	*6.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.73	.73	.73	.77	2.96
2017	.825	.825	.825	.825	3.30
2018	.8625	.8625	.8625	.8625	3.53
2019	.945	.945	.945	.945	3.78
2020	1.0125	1.0125			

BUSINESS: DTE Energy Company is a holding company for DTE Electric (formerly Detroit Edison), which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and DTE Gas (formerly Michigan Consolidated Gas). Customers: 2.2 mill. electric, 1.3 mill. gas. Has various nonutility operations. Electric revenue breakdown: residential, 46%; commercial, 34%; industrial, 13%; other, 7%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 54% of revenues. '19 reported deprec. rates: 4.0% electric, 2.7% gas. Has 10,700 employees. Chairman: Gerard M. Anderson. President & CEO: Jerry Norcia. Inc.: MI. Address: One Energy Plaza, Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility subsidiary received a rate increase. DTE Electric was granted a hike of $188 million, based on a return on equity of 9.9% and a common-equity ratio of 50%. The utility had filed for an increase of $351 million, but we consider the order constructive. New tariffs took effect on May 15th. DTE Electric plans to put forth another application this summer, with a decision due 10 months after the filing date. The utility is determining whether delaying the next application is feasible, considering the state of the economy.

DTE Gas has a rate case pending. The utility is seeking an increase of $196 million, based on a 10.5% ROE and a 52% common-equity ratio. The staff of the Michigan commission recommended a boost of $92 million, based on a 9.6% ROE and a 50% equity ratio. New rates are expected to take effect in October. Once DTE Gas receives a decision, its next rate case will probably be at least two years away.

We have not adjusted our earnings estimates for 2020 and 2021, despite the economic downturn. DTE Electric estimates that the decline in commercial and industrial kilowatt-hour sales (only partially offset by increased residential volume as people work from home) will hurt the bottom line by $30 million-$50 million. Management believes it can cut operating expenses to compensate for this. It helps that certain parts of the utility's service area, such as the automakers' plants, began reopening in May. In addition, the company's nonutility operations were actually ahead of plan in the March quarter. DTE Energy is sticking with its 2020 share-net guidance of $6.47-$6.75.

The Gas Storage and Pipeline division is performing well. Wall Street expressed concern that low natural gas prices would hurt this business, but the company benefits from long-term contracts. An acquisition that DTE Energy completed in December is expected to contribute $0.15 to share profits this year.

This stock's dividend yield is slightly above average for a utility. The price is down 16% this year, in line with other utilities. Total return potential is average for the 18-month period, but unspectacular for the pull to 2023-2025.

Paul E. Debbas, CFA *June 12, 2020*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, (2¢); '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on disc. ops.: '04, (6¢); '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢; '12, (33¢). '17-'18 EPS don't sum due to rounding. Next earnings report due late July. (B) Div'ds pd. mid-Jan., Apr., July & Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '19: $47.33/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '20: 9.9% elec.; in '16: 10.1% gas; earn. on avg. com. eq., '19: 10.8%. Regulat. Climate: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	85

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DUKE ENERGY NYSE-DUK

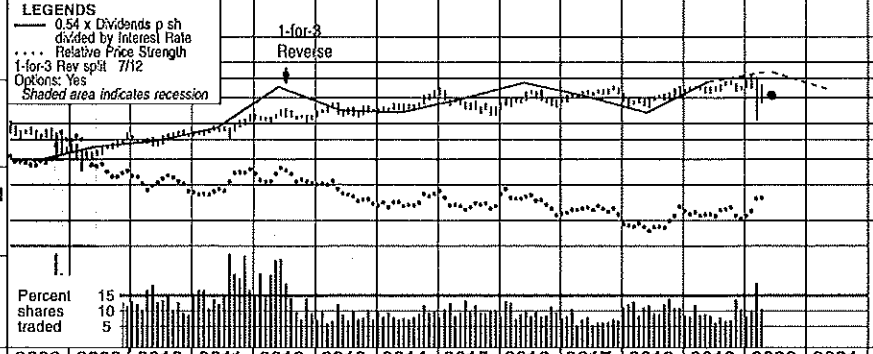
RECENT PRICE 82.63 | P/E RATIO 16.2 (Trailing: 16.3 Median: 18.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 3 Lowered 3/13/20
SAFETY 2 New 6/1/07
TECHNICAL 3 Raised 4/3/20
BETA .85 (1.00 = Market)

High:	53.8	55.8	66.4	71.1	75.5	87.3	90.0	87.8	91.8	91.4	97.4	103.8
Low:	35.2	46.4	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5	62.1

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.54 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$76-$113	$95 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+25%)	10%
Low	80	(-5%)	4%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	682	711	806
to Sell	586	582	557
Hld's(000)	7059915	445072	476731

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.1	-15.6
3 yr.	15.5	-2.4
5 yr.	34.1	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
--	--	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	*33.25*	*33.95*	Revenues per sh	*36.25*
--	--	7.88	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	10.49	12.13	*12.05*	*12.75*	"Cash Flow" per sh	*14.25*
--	--	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.13	5.07	*5.10*	*5.30*	Earnings per sh A	*6.00*
--	--	--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	*3.82*	*3.89*	Div'd Decl'd per sh B ■	*4.10*
--	--	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	*15.50*	*14.70*	Cap'l Spending per sh	*13.75*
--	--	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	*63.80*	*65.35*	Book Value per sh C	*71.00*
--	--	418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	733.00	*764.00*	*770.00*	Common Shs Outst'g D	*785.00*
--	--	--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	19.4	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
--	--	--	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	1.05	.95	*Value Line*		Relative P/E Ratio	*.85*
--	--	--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.4%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $61261 mill. Due in 5 Yrs $20740 mill.
LT Debt $54985 mill. LT Interest $2155 mill.
Incl. $969 mill. capitalized leases.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $268 mill.
Pension Assets-12/19 $8910 mill.
Oblig $8231 mill.
Pfd Stock $1962 mill. Pfd Div'd $58 mill.
40 mill. shs. 5.75%, cum., $25 liq. value, redeemable at $25.50 prior to 6/15/24; 1 mill. shs. 4.875%, cum., $1000 liq. value.
Common Stock 733,321,965 shs. as of 1/31/20
MARKET CAP: $61 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
14272	14529	19624	24598	23925	23459	22743	23565	24521	25079	*25400*	*26150*	Revenues ($mill)	*28500*
1765.0	1839.0	2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	2928.0	3755.0	*3860*	*4170*	Net Profit ($mill)	*4740*
32.6%	31.3%	30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.2%	12.7%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
22.7%	23.2%	22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	13.0%	7.9%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
44.3%	45.1%	47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	*52.5%*	*53.0%*	Long-Term Debt Ratio	*53.5%*
55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	*45.5%*	*45.5%*	Common Equity Ratio	*45.0%*
40457	41451	77307	79482	78088	77222	86609	90774	94940	101807	*106650*	*110725*	Total Capital ($mill)	*123600*
40344	42661	68558	69490	70046	75709	82520	86391	91694	102127	*108475*	*114050*	Net Plant ($mill)	*128400*
5.5%	5.6%	3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.2%	4.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.0%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.0%*
7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.3%	*7.5%*	*8.0%*	Return on Com Equity E	*8.5%*
2.1%	2.2%	.9%	1.5%	1.7%	1.5%	.6%	1.2%	1.0%	2.4%	*2.0%*	*2.0%*	Retained to Com Eq	*2.5%*
73%	72%	82%	76%	76%	79%	91%	83%	84%	71%	*77%*	*74%*	All Div'ds to Net Prof	*70%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.0	+3.9	-.9
Avg. Indust. Use (MWH)	2914	2953	2934
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.3	+1.4	+1.5
Fixed Charge Cov. (%)	272	218	233

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	1.0%	1.0%	*1.0%*
"Cash Flow"	3.5%	6.0%	*4.5%*
Earnings	3.0%	2.5%	*5.0%*
Dividends	3.0%	3.0%	*2.0%*
Book Value	2.0%	1.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	5729	5555	6482	5799	23565
2018	6135	5643	6628	6115	24521
2019	6163	5873	6940	6103	25079
2020	*6250*	*5900*	*7000*	*6250*	*25400*
2021	*6450*	*6050*	*7200*	*6450*	*26150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.02	.98	1.36	.86	4.22
2018	1.17	.71	1.63	.61	4.13
2019	1.24	1.12	1.82	.89	5.07
2020	*1.30*	*1.05*	*1.80*	*.95*	*5.10*
2021	*1.35*	*1.10*	*1.90*	*.95*	*5.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.825	.825	.855	.855	3.36
2017	.855	.855	.89	.89	3.49
2018	.89	.89	.927	.928	3.64
2019	.927	.928	.945	.945	3.75
2020	.945				

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & KY, and 1.6 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 44%; commercial, 28%; industrial, 14%; other, 14%. Generating sources: gas, 29%; nuclear, 29%; coal, 22%; other, 1%; purchased, 19%. Fuel costs: 30% of revs. '19 reported deprec. rate: 3.1%. Has 28,800 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy has some rate cases pending. In North Carolina, Duke Energy Carolinas and Duke Energy Progress are seeking increases of $291 million (6.0%) and $464 million (12.3%), respectively, based on a 10.3% return on equity and a 53% common-equity ratio. In Indiana, the utility filed for a hike of $395 million (15%), based on a 10.4% ROE and a 53% common-equity ratio. Duke is seeking $345 million in 2020 and $50 million in 2021. In Kentucky, the company requested a boost of $46 million (12.5%), based on a 9.8% ROE and a 48% common-equity ratio. However . . .

There might well be delays in receiving rate relief. Hearings on the Duke Energy Carolinas proceeding have been delayed due to the coronavirus-related disruptions to normal operations. New tariffs were expected to take effect in the third quarter of 2020; how long implementation will be delayed, and whether the utility will be able to get interim rate relief, is unknown. Also unknown is whether orders in other states will be delayed.

We estimate just a slight profit increase this year. We are not assuming that Duke will obtain interim rate relief if any rate orders are delayed. In addition, the weak economy will hurt commercial and industrial kilowatt-hour sales. We have lowered our 2020 share-earnings estimate by $0.10, to $5.10. This is near the low end of the company's targeted range of $5.05-$5.45 (which was issued in mid-February, when the economy was in better shape). We think rate relief and a better economy will produce a 4% earnings increase in 2021, within Duke's annual growth goal of 4%-6%.

The cost of a proposed gas pipeline has risen again. Litigation has delayed the 47%-owned project and caused sizable cost overruns. The latest estimate is $8.0 billion, up from $7.3 billion-$7.8 billion. Duke will issue $2.5 billion of common equity (through a forward sale) by yearend to finance its share of the pipeline.

This stock has an above-average dividend yield for a utility. But total return potential is lackluster for the 18-month and 3- to 5-year periods. The stock price is down 9% this year, which is less than the fall in most utility issues.

Paul E. Debbas, CFA *May 15, 2020*

(A) Diluted EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; '17, 15¢; '18, 41¢; losses on disc. ops.: '14, 80¢; '16, 60¢; '18 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $44.37/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '18 in NC: 9.9%; in '19 in SC: 9.5%; in '20 in FL: 9.5%-11.5%; in '04 in IN: 10.5%; earned on avg. com. eq., '19: 8.3%. Reg. Clim.: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	90

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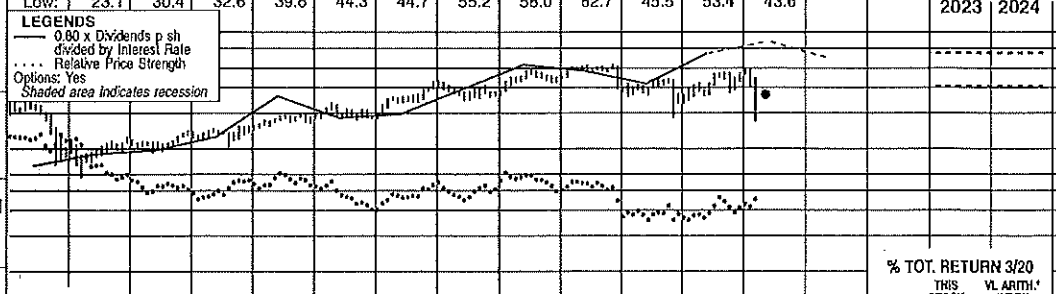
EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 59.39 | P/E RATIO 15.6 (Trailing: 14.8 Median: 14.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 8/30/19
SAFETY 3 Lowered 11/23/18
TECHNICAL 3 Lowered 4/24/20
BETA .55 (1.00 = Market)

High:	36.7	39.4	41.6	48.0	54.2	68.7	69.6	78.7	83.4	71.0	76.4	78.9
Low:	23.1	30.4	32.6	39.6	44.3	44.7	55.2	58.0	62.7	45.5	53.4	43.6

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025
120 100 80 64 48 32 24 20 16 12 8

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$49-$92	$71 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+60%)	16%
Low	65	(+10%)	7%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	267	339	328
to Sell	301	231	243
Hld's(000)	278546	316321	325429

Percent shares traded 30 20 10

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-8.2	-26.1
3 yr.	-23.3	-16.7
5 yr.	3.4	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	38.85	34.11	*34.65*	*35.80*	Revenues per sh	*40.00*
3.79	6.99	7.25	7.60	8.08	7.96	6.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	9.15	*10.05*	*10.40*	"Cash Flow" per sh	*11.75*
.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	3.98	*4.20*	*4.25*	Earnings per sh A	*4.75*
.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	2.43	2.48	*2.58*	*2.68*	Div'd Decl'd per sh B ■	*3.00*
5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	13.84	13.47	*13.35*	*14.20*	Cap'l Spending per sh	*13.75*
18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.88	28.95	30.50	33.64	34.89	36.82	35.82	32.10	36.75	*39.20*	*41.20*	Book Value per sh C	*47.50*
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	361.99	*375.00*	*380.00*	Common Shs Outst'g D	*395.00*
37.6	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	--	16.7	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
1.99	.62	.70	.65	.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	--	.90	*Value Line*		Relative P/E Ratio	*.90*
3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.6%	2.8%	2.9%	3.8%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $18893 mill. Due in 5 Yrs $4922 mill.
LT Debt $17864 mill. LT Interest $840 mill.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $107 mill.
Pens. Assets-12/19 $3755 mill. Oblig $4139 mill.
Pfd Stock $2193 mill. Pfd Div'd $121 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. variable, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 362,570,075 shs. as of 2/20/20
MARKET CAP: $22 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
12409	12760	11662	12561	13413	11524	11669	12320	12657	12347	*13000*	*13600*	Revenues ($mill)	*15800*
1153.0	1112.0	1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	d290.0	1477.0	*1670*	*1740*	Net Profit ($mill)	*2030*
32.1%	25.7%	14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	--	--	*Nil*	*Nil*	Income Tax Rate	*Nil*
16.9%	14.8%	8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	--	11.1%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*9.0%*
51.8%	55.3%	45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	53.6%	53.5%	*53.5%*	*54.5%*	Long-Term Debt Ratio	*56.5%*
44.3%	40.6%	46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	38.3%	39.9%	*40.5%*	*40.0%*	Common Equity Ratio	*39.0%*
23861	24773	20422	21516	23216	24352	24362	25506	27284	33360	*36425*	*39325*	Total Capital ($mill)	*48300*
24778	32116	30273	30455	32981	35085	37000	39050	41348	44285	*47075*	*50125*	Net Plant ($mill)	*58500*
6.3%	6.0%	8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	.1%	5.6%	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.0%	10.0%	14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	NMF	9.5%	*10.0%*	*9.5%*	Return on Shr. Equity	*9.5%*
10.4%	10.5%	15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	NMF	10.2%	*10.5%*	*10.5%*	Return on Com Equity E	*10.0%*
6.5%	6.3%	11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	NMF	4.1%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
40%	43%	32%	40%	37%	44%	53%	52%	NMF	63%	*64%*	*65%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+.2	-.4	-2.7
Avg. Indust. Use (MWH)	643	667	657
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	23508	23766	22009
Annual Load Factor (%)	48.8	48.0	49.6
% Change Customers (yr-end)	+.7	+.6	+.5
Fixed Charge Cov. (%)	241	NMF	172

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-1.0%	-1.0%	*1.5%*
"Cash Flow"	.5%	-2.5%	*6.0%*
Earnings	-3.5%	-10.5%	*NMF*
Dividends	7.0%	11.5%	*4.0%*
Book Value	2.0%	2.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2463	2965	3672	3220	12320
2018	2564	2815	4269	3009	12657
2019	2824	2812	3741	2970	12347
2020	*2900*	*3000*	*4000*	*3100*	*13000*
2021	*3050*	*3150*	*4150*	*3250*	*13600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.11	.85	1.43	1.12	4.51
2018	.82	.84	1.57	d4.49	d1.26
2019	.64	1.57	1.35	.45	3.98
2020	*.95*	*.95*	*1.45*	*.85*	*4.20*
2021	*.95*	*.95*	*1.50*	*.85*	*4.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.48	.48	.48	.48	1.92
2017	.5425	.5425	.5425	.5425	2.17
2018	.605	.605	.605	.605	2.42
2019	.6125	.6125	.6125	.6125	2.45
2020	.6375				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.1 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 39%; commercial, 43%; industrial, 4%; other, 14%. Generating sources: nuclear, 8%; gas, 7%; hydro, 5%; purchased, 80%. Fuel costs: 39% of revs. '19 reported depr. rate: 3.6%. Has 12,500 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Edison International's utility subsidiary has a general rate case pending. Southern California Edison filed for rate hikes of $1.109 billion (11.4%) in 2021, $423 million in 2022, and $514 million in 2023. An order is expected by yearend, but even if this slips into 2021, it will be retroactive to the start of next year. SCE's three-year capital spending plan includes $4.4 billiou for wildfire mitigation measures, but the utility will not earn an equity return on $1.1 billion of this amount. Historically, the California commission has approved most, but not all, of the utility's capital spending request.

In a separate procceding, the utility is asking the California commission for a reasonableness review of wildfire-related costs. SCE wants a rate hike of $500 million to recover capital and operating costs incurred through year-end 2019 for the company's wildfire-mitigation activities. A decision is expected in the second quarter of 2021.

Wildfires are still an important investment consideration for the company. It took a $4.7 billion reserve in the fourth quarter of 2018 and a $255 million charge in the fourth period of 2019. We *include* these charges in our earnings presentation because they are operational in nature. We are also including the amortization of costs SCE incurred for the wildfire fund. These will amount to about $300 million annually (pretax) through mid-2029. Note that Edison International excludes this from its 2020 earnings target of $4.32-$4.62 a share. This is why our estimate of $4.20 a share is below the company's guidance.

Financing needs are significaut. Edison International plans to add $800 million of common equity this year. As of early April, the company had issued $2.7 billion of long-term debt. Edison International's financing costs explain why we look for just a slight earnings increase next year, despite the likelihood that SCE will receive rate relief.

The dividend yield of this stock is above avcrage for a utility. Total return potential for the 18-month and 3- to 5-year periods is also better than that of most utilities. However, investors must be willing to assume the risks associated with wildfire liabilities.

Paul E. Debbas, CFA *April 24, 2020*

(A) Dil. EPS. Excl. nonrec. gains (losses): '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (15¢); '19, (21¢); gains (loss) from disc. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. '19 EPS don't sum due to chng. in shs. Next earnings report due late Apr. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd charges. In '19: $16.82/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '20: 10.3%; earned on avg. com. eq., '19: 11.5%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	60
Earnings Predictability	10

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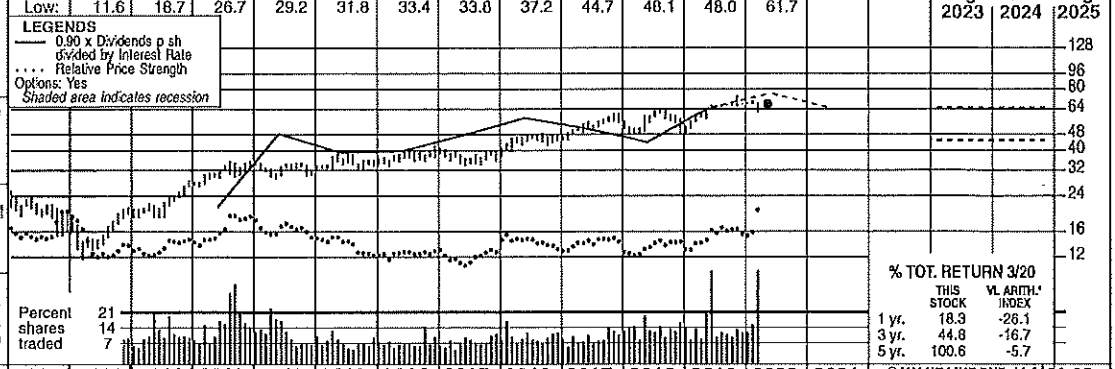
EL PASO ELECTRIC NYSE-EE

RECENT PRICE 67.77 | P/E RATIO 25.9 (Trailing: 22.4 Median: 17.0) | RELATIVE P/E RATIO 1.77 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS — Suspended 6/14/19
SAFETY 2 Raised 5/11/07
TECHNICAL — Suspended 6/14/19
BETA .60 (1.00 = Market)

High:	21.1	28.7	35.7	35.3	39.1	42.2	41.3	48.8	61.2	64.4	74.4	70.0
Low:	11.6	18.7	26.7	29.2	31.8	33.4	33.8	37.2	44.7	48.1	48.0	61.7

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$52-$77	$65 (-5%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(-5%)	2%
Low	45	(-35%)	-6%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	116	99	106
to Sell	118	100	80
Hld's(000)	37767	37508	38840

Percent shares traded 21 14 7

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.3	-26.1
3 yr.	44.8	-16.7
5 yr.	100.6	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.01	21.89	22.59	22.21	21.16	*20.70*	*21.20*	Revenues per sh	*22.50*
3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	5.75	5.98	6.17	5.89	6.98	*6.20*	*6.75*	"Cash Flow" per sh	*7.50*
.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.03	2.39	2.42	2.07	3.01	*2.25*	*2.60*	Earnings per sh A	*2.75*
--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	1.23	1.32	1.42	1.52	*1.62*	*1.72*	Div'd Decl'd per sh B	*2.05*
1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	8.55	7.03	5.91	6.84	6.36	*7.20*	*8.15*	Cap'l Spending per sh	*8.75*
11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.13	26.52	28.14	28.62	29.87	*31.80*	*32.50*	Book Value per sh C	*34.25*
47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.44	40.52	40.58	40.68	40.73	*42.25*	*42.50*	Common Shs Outst'g D	*43.25*
22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.3	18.7	21.8	26.8	20.8	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.92	.98	1.10	1.45	1.12	*Value Line*		Relative P/E Ratio	*1.10*
--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%	2.7%	2.5%	2.5%	2.4%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $1499.8 mill. Due in 5 Yrs $308.8 mill.
LT Debt $1341.0 mill. LT Interest $75.9 mill.
(LT interest earned: 2.9x)

Pension Assets-12/19 $327.2 mill. Oblig $398.1 mill.

Pfd Stock None

Common Stock 40,752,141 shs. as of 1/31/20

MARKET CAP: $2.8 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
877.3	918.0	852.9	890.4	917.5	849.9	886.9	916.8	903.6	862.0	*875*	*900*	Revenues ($mill)	*975*
90.3	103.5	90.8	88.6	91.4	81.9	96.8	98.3	84.3	123.0	*95.0*	*110*	Net Profit ($mill)	*120*
36.1%	34.2%	34.1%	33.0%	31.0%	29.9%	35.8%	34.2%	23.8%	21.7%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
22.1%	17.6%	22.4%	24.1%	30.8%	27.5%	17.6%	11.2%	14.9%	10.0%	*14.0%*	*16.0%*	AFUDC % to Net Profit	*15.0%*
51.2%	51.8%	54.8%	51.4%	53.5%	52.7%	52.7%	51.2%	52.5%	52.4%	*50.0%*	*52.0%*	Long-Term Debt Ratio	*52.5%*
48.8%	48.2%	45.2%	48.6%	46.5%	47.3%	47.3%	48.8%	47.5%	47.6%	*50.0%*	*48.0%*	Common Equity Ratio	*47.5%*
1660.1	1576.7	1824.5	1943.5	2118.4	2150.8	2269.9	2338.2	2450.1	2557.5	*2685*	*2875*	Total Capital ($mill)	*3125*
1865.8	1947.1	2102.3	2257.5	2488.4	2695.5	2821.2	2928.4	3085.0	3227.1	*3365*	*3535*	Net Plant ($mill)	*4075*
7.0%	8.3%	6.5%	6.1%	5.7%	5.3%	5.8%	5.8%	5.0%	6.3%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	8.6%	7.2%	10.1%	*7.0%*	*8.0%*	Return on Shr. Equity	*8.0%*
11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	8.6%	7.2%	10.1%	*7.0%*	*8.0%*	Return on Com Equity E	*8.0%*
11.1%	10.0%	6.3%	4.9%	4.8%	3.4%	4.4%	3.9%	2.3%	5.0%	*2.0%*	*3.0%*	Retained to Com Eq	*2.5%*
--	26%	43%	47%	49%	57%	51%	54%	68%	50%	*72%*	*65%*	All Div'ds to Net Prof	*73%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+.4	+2.4	-.4
Avg. Indust. Use (MWH)	21553	21892	21420
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2082	2085	2085
Peak Load, Summer (Mw)	1935	1929	1985
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.7	+1.7	+1.8
Fixed Charge Cov. (%)	263	185	185

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	.5%	--	*.5%*
"Cash Flow"	4.5%	2.0%	*3.0%*
Earnings	4.5%	2.0%	*1.5%*
Dividends	--	6.5%	*6.5%*
Book Value	6.5%	5.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	171.3	251.8	297.5	196.2	916.8
2018	175.7	236.8	300.3	190.8	903.6
2019	174.4	203.1	294.4	190.1	862.0
2020	*175*	*210*	*300*	*190*	*875*
2021	*180*	*215*	*310*	*195*	*900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	d.10	.89	1.47	.16	2.42
2018	d.17	.82	1.79	d.38	2.07
2019	.15	.64	1.91	.32	3.01
2020	*d.40*	*.80*	*1.90*	*d.05*	*2.25*
2021	*d.15*	*.85*	*1.95*	*d.05*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.295	.31	.31	.31	1.23
2017	.31	.335	.335	.335	1.32
2018	.335	.36	.36	.36	1.42
2019	.36	.385	.385	.385	1.52
2020	.385				

BUSINESS: El Paso Electric Company (EPE) provides electric service to 433,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: gas, 45%; nuclear, 44%; purchased, 11%. Fuel costs: 20% of revenues. '19 reported depreciation rate: 2.3%. Has about 1,100 employees. Chairman: Charles A. Yamarone. Interim CEO: Adrian J. Rodriguez. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, TX 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

The pending acquisition of El Paso Electric Company is moving closer to completion. The Infrastructure Investments Fund, advised by J.P. Morgan, has agreed to pay $68.25 in cash for each share of EPE. The deal has been approved by shareholders, the Public Utility Commission of Texas, the New Mexico Public Regulation Commission, and the Nuclear Regulatory Commission. The El Paso City Council has consented to the transfer of the franchise to the buyer. The Federal Energy Regulatory Commission has given its conditional approval, and EPE believes it can meet the commission's conditions. The companies expect the takeover to be completed in the first half of 2020. Accordingly, this is probably our last full-page report on EPE.

We continue to advise stockholders to sell their shares on the open market. The recent quotation is just slightly below the buyout price, so there is little to be gained by waiting for the deal to close. If the transaction falls through, this would almost certainly hurt the stock price. The Timeliness rank remains suspended because the equity is trading on the basis of the pending takeover.

The performance of the stock market affects the company's earnings. EPE's stake in Unit 3 of the Palo Verde nuclear station is a nonregulated asset. Unrealized gains or losses on the nuclear decommissioning trust flow through to the income statement. The market's strong showing in 2019 boosted EPE's share earnings above the $3.00 level last year (despite merger-related costs that amounted to $0.25 a share). However, the market's poor performance in the first quarter of 2020 means EPE will almost certainly report a larger-than-usual loss for the period. The company will incur merger-related costs, too, probably below the $0.06 a share recorded in the fourth quarter of 2019.

The utility is asking the Texas and New Mexico commissions to approve its plan for adding generating resources. EPE intends to build a 228-megawatt gas-fired plant at a cost of $143 million and enter into purchased-power agreements for 200 mw of solar capacity and 100 mw of battery storage. Rulings are expected by yearend.

Paul E. Debbas, CFA *April 24, 2020*

(A) Diluted earnings. Excl. nonrecurring gains (loss): '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '18 & '19 EPS don't sum due to rounding. Next earnings report due early May. (B) Initial div'd declared 4/11; payment dates in late Mar., June, Sept., & Dec. (C) Incl. deferred charges. In '19: $1.74/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in TX in '17: 9.65%; in NM in '16: 9.48%; earned on avg. com. eq., '19: 10.3%. Regulatory Climate: TX, Average; NM, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	75

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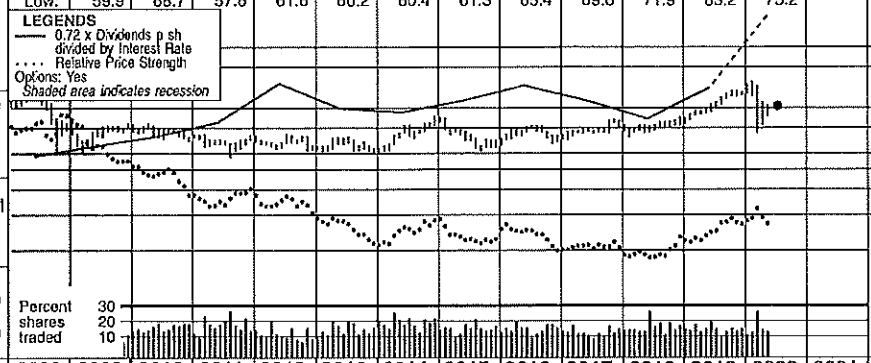
ENTERGY CORP. NYSE-ETR

RECENT PRICE 102.68 | P/E RATIO 20.3 (Trailing: 18.4 Median: 13.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 3 Raised 10/26/18
SAFETY 2 Raised 12/13/19
TECHNICAL 3 Lowered 6/5/20
BETA .95 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
High:	86.6	84.3	74.5	74.5	72.6	92.0	90.3	82.1	87.9	90.8	122.1	135.5
Low:	59.9	68.7	57.6	61.6	60.2	60.4	61.3	65.4	69.6	71.9	83.2	75.2

LEGENDS
— 0.72 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$74-$166 $120 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	140	(+35%)	11%
Low	100	(-5%)	3%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	298	348	281
to Sell	248	242	349
Hld's(000)	175725	176392	172217

Percent shares traded 30 20 10

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.7	-1.3
3 yr.	44.1	5.2
5 yr.	63.8	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
46.69	46.61	53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	58.23	54.63	*51.25*	*50.50*	Revenues per sh	*50.00*
8.33	8.16	10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	16.50	17.19	*16.70*	*17.95*	"Cash Flow" per sh	*21.00*
3.93	4.40	5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	5.88	6.30	*5.05*	*5.80*	Earnings per sh A	*7.00*
1.89	2.16	2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	3.58	3.66	*3.74*	*3.86*	Div'd Decl'd per sh B ■ †	*4.55*
6.51	6.72	9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	22.45	21.72	*20.75*	*19.15*	Cap'l Spending per sh	*18.75*
38.26	35.71	40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	46.78	51.34	*52.80*	*55.20*	Book Value per sh C	*62.75*
216.83	216.83	202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	189.06	199.15	*200.00*	*204.00*	Common Shs Outst'g D	*212.00*
15.1	16.3	14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.80	.67	.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	*Value Line*		Relative P/E Ratio	*.95*
3.2%	3.0%	2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $21400 mill. Due in 5 Yrs $8317.4 mill.
LT Debt $18229 mill. LT Interest $810.0 mill.
Incl. $271.4 mill. of securitization bonds.
(LT interest earned: 1.8x)
Leases, Uncapitalized Annual rentals $62.1 mill.
Pension Assets-12/19 $6271.2 mill.
Oblig $8406.2 mill.
Pfd Stock $254.4 mill. Pfd Div'd $18.3 mill.
200,000 shs. 6.25%-7.5%, $100 par; 250,000 shs. 8.75%, 1.4 mill. shs. 5.375%; all cum., without sinking fund.
Common Stock 200,161,934 shs. as of 4/30/20
MARKET CAP: $21 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
11488	11229	10302	11391	12495	11513	10846	11074	11009	10879	*10250*	*10300*	Revenues ($mill)	*10600*
1270.3	1367.4	1091.9	904.5	1060.0	1061.2	1249.8	950.7	1092.1	1258.2	*1030*	*1195*	Net Profit ($mill)	*1490*
32.7%	17.3%	13.0%	26.7%	37.8%	2.2%	11.3%	1.8%	1.8%	NMF	*18.0%*	*22.0%*	Income Tax Rate	*22.0%*
7.4%	8.9%	11.9%	10.1%	9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	*19.0%*	*16.0%*	AFUDC % to Net Profit	*13.0%*
56.3%	52.2%	55.8%	55.1%	54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	*62.0%*	*62.0%*	Long-Term Debt Ratio	*58.5%*
42.1%	46.4%	42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	*37.5%*	*37.5%*	Common Equity Ratio	*41.0%*
20166	19324	21432	22109	22842	22714	22777	22528	24602	27557	*28350*	*30150*	Total Capital ($mill)	*32500*
23848	25609	27299	27882	28723	27824	27921	29664	31974	35183	*37050*	*38525*	Net Plant ($mill)	*41700*
7.7%	8.5%	6.4%	5.4%	6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
14.4%	14.8%	11.5%	9.1%	10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	*9.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
14.7%	15.0%	11.6%	9.2%	10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	*9.5%*	*10.5%*	Return on Com Equity E	*11.0%*
7.6%	8.4%	5.2%	3.0%	4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	*2.5%*	*3.5%*	Retained to Com Eq	*4.0%*
49%	45%	56%	68%	58%	58%	50%	68%	61%	58%	*74%*	*67%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+.2	+4.1	-1.4
Avg. Indust. Use (MWH)	1034	946	NA
Avg. Indust. Revs. per KWH(¢)	5.41	5.16	5.24
Capacity at Peak (Mw)	24279	23121	NA
Peak Load, Summer (Mw)	21671	21587	21598
Annual Load Factor (%)	62	65	NA
% Change Customers (yr-end)	+.6	+.6	NA
Fixed Charge Cov. (%)	169	95	165

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-.5%	-2.0%	*-2.5%*
"Cash Flow"	3.0%	--	*4.0%*
Earnings	-.5%	.5%	*3.0%*
Dividends	2.5%	1.5%	*4.0%*
Book Value	1.0%	-2.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2588	2618	3244	2624	11074
2018	2724	2669	3104	2512	11009
2019	2610	2666	3141	2462	10879
2020	2427	*2423*	*3000*	*2400*	*10250*
2021	*2600*	*2500*	*2900*	*2300*	*10300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.46	2.27	2.21	.25	5.19
2018	.73	1.34	3.42	.39	5.88
2019	1.32	1.22	1.82	1.94	6.30
2020	.59	*1.25*	*2.45*	*.76*	*5.05*
2021	*1.10*	*1.50*	*2.60*	*.60*	*5.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.85	.85	.85	.87	3.42
2017	.87	.87	.87	.89	3.50
2018	.89	.89	.89	.91	3.58
2019	.91	.91	.91	.93	3.66
2020	.93	.93			

BUSINESS: Entergy Corporation supplies electricity to 2.9 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 202,000 customers in Louisiana. Has a nonutility subsidiary that owns six nuclear units (four no longer operating). Electric revenue breakdown: residential, 38%; commercial, 26%; industrial, 27%; other, 9%. Generating sources: gas, 40%; nuclear, 28%; coal, 6%; purchased, 26%. Fuel costs: 30% of revenues. '19 reported depreciation rate: 2.8%. Has 13,600 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy's earnings are likely to decline this year. The fourth quarter of 2019 benefited from tax credits, which we *included* in our earnings presentation because the company has recorded similar benefits in previous years. In addition, Entergy's nonutility activities (primarily nonregulated nuclear units) lost $0.55 a share in the first quarter of 2020. The company is exiting most of these operations and excludes these results from its 2020 earnings guidance of $5.45-$5.75, but we include these results. We cut our 2020 earnings estimate by $0.40 a share, to $5.05, because March-quarter results were below our $1.00 estimate.

The company did not change its earnings guidance, despite the falloff in the economy. Management estimates the slump in commercial and industrial kilowatt-hour sales will reduce revenues by $120 million-$140 million this year, only partially offset by rising residential volume. In response, Entergy is cutting operating and maintenance expenses by $100 million. The company's utilities are deferring for future recovery their costs associated with the coronavirus problem. Entergy's targeted range for 2021 profits remains $5.80-$6.10 a share. Our estimate is at the bottom end of this range.

Entergy Louisiana completed a gas-fired generating plant in March, and three more gas-fired facilities are under construction. The new plant cost $872 million for 994 megawatts of capacity. Entergy New Orleans is adding 128 mw at a cost of $210 million, Entergy Louisiana is building a 361-mw facility for $261 million, and Entergy Texas is constructing 993 mw at a cost of $937 million. These facilities are still needed to meet customer demand, despite the recession, and will boost the company's earning power. The utilities will recover the costs of these projects either with a general rate case or through a formula rate plan.

The valuation of Entergy stock is about average for a utility. The dividend yield is close to the industry mean. The stock has declined 14% this year, a similar proportion to many utility issues. Total return potential is about average for the 18-month span and unspectacular for the 3- to 5-year period.

Paul E. Debbas, CFA *June 12, 2020*

(A) Diluted EPS. Excl. nonrec. losses: '05, 21¢; '12, $1.26; '13, $1.14; '14, 56¢; '15, $6.99; '16, $10.14; '17, $2.91; '18, $1.25. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. def'd charges. In '19: $29.67/sh. (D) In millions. (E) Rate base: Net original cost. Allowed ROE (blended): 9.95%; earned on avg. com. eq., '19: 13.0%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	20
Earnings Predictability	60

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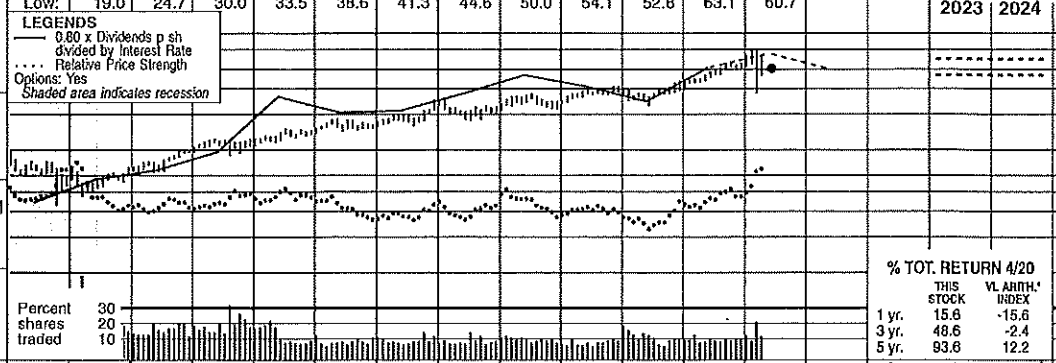
EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 80.80 | P/E RATIO 22.1 (Trailing: 23.4 Median: 18.0) | RELATIVE P/E RATIO 1.33 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 2 Lowered 5/8/20
SAFETY 1 Raised 5/22/15
TECHNICAL 1 Raised 4/24/20
BETA .90 (1.00 = Market)

High:	26.5	32.2	36.5	40.9	45.7	56.7	56.8	60.4	66.1	70.5	86.6	99.4	
Low:	19.0	24.7	30.0	33.5	38.6	41.3	44.6	50.0	54.1	52.8	63.1	60.7	

Target Price Range 2023 | 2024 | 2025



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$72-$105	$89 (10%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+10%)	6%
Low	75	(-5%)	2%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	327	357	390
to Sell	269	268	260
Hld's(000)	255223	265386	272541

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.6	-15.6
3 yr.	48.6	-2.4
5 yr.	93.6	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	24.11	24.46	26.66	25.85	*25.65*	*26.10*	Revenues per sh	*28.25*
5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.46	5.84	6.64	6.85	*6.95*	*7.30*	"Cash Flow" per sh	*8.75*
.91	.96	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.96	3.11	3.25	3.45	*3.65*	*3.85*	Earnings per sh A	*4.75*
.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	2.02	2.14	*2.27*	*2.40*	Div'd Decl'd per sh B ■	*2.85*
4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	6.24	7.41	7.96	8.83	*9.05*	*8.25*	Cap'l Spending per sh	*7.75*
17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	34.99	36.25	38.29	*40.80*	*42.65*	Book Value per sh C	*48.75*
129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	316.89	316.89	316.89	329.88	*339.00*	*343.00*	Common Shs Outst'g D	*355.00*
20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.7	19.5	18.7	22.1	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	1.19	*Value Line*		Relative P/E Ratio	*1.00*
3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	3.1%	3.3%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $15571 mill. Due in 5 Yrs $6197.2 mill.
LT Debt $14311 mill. LT Interest $565.3 mill.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $10.2 mill.
Pension Assets-12/19 $4968.6 mill.
Oblig $6321.7 mill.
Pfd Stock $155.6 mill. Pfd Div'd $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption, call. at $50.50-$54.00; 430,000 shs 4.25%-4.78% not subject to mandatory redemption, call. at $102.80-$103.63.
Common Stock 329,952,663 shs. as of 1/31/20
MARKET CAP: $27 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
4898.2	4465.7	6273.8	7301.2	7741.9	7954.8	7639.1	7752.0	8448.2	8526.5	*8700*	*8950*	Revenues ($mill)	*10000*
377.8	400.3	533.0	793.7	827.1	886.0	949.8	995.5	1040.5	1121.0	*1235*	*1320*	Net Profit ($mill)	*1680*
36.6%	29.9%	34.0%	35.0%	36.2%	37.9%	36.9%	36.8%	21.7%	19.7%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
7.1%	8.6%	2.3%	1.4%	2.4%	2.9%	3.9%	4.7%	6.1%	6.3%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
55.1%	53.4%	43.7%	44.3%	45.9%	45.6%	44.8%	51.2%	52.4%	52.8%	*52.0%*	*52.5%*	Long-Term Debt Ratio	*54.0%*
43.6%	45.3%	55.4%	54.8%	53.2%	53.6%	54.4%	48.2%	46.9%	46.6%	*47.0%*	*47.0%*	Common Equity Ratio	*46.0%*
8741.8	8856.0	16675	17544	18738	19313	19697	23018	24474	27097	*29300*	*31200*	Total Capital ($mill)	*37800*
9567.7	10403	16605	17576	18647	19892	21351	23617	25610	27585	*29675*	*31475*	Net Plant ($mill)	*36200*
5.8%	5.9%	4.2%	5.5%	5.3%	5.5%	5.8%	5.2%	5.2%	5.1%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.6%	9.7%	5.7%	8.1%	8.2%	8.4%	8.7%	8.9%	8.9%	8.8%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
9.8%	9.8%	5.7%	8.2%	8.2%	8.5%	8.8%	8.9%	9.0%	8.8%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
5.0%	5.0%	1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	3.4%	3.6%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
49%	50%	72%	59%	58%	61%	60%	61%	62%	60%	*62%*	*62%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.6	+2.2	-3.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.5	+.7
Fixed Charge Cov. (%)	427	319	319

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-3.0%	2.5%	*1.5%*
"Cash Flow"	2.0%	6.5%	*5.5%*
Earnings	6.0%	7.0%	*6.5%*
Dividends	9.0%	7.0%	*6.0%*
Book Value	6.5%	3.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2105	1762	1988	1895	7752.0
2018	2288	1853	2271	2034	8448.1
2019	2415	1884	2175	2050	8526.5
2020	*2450*	*1950*	*2200*	*2100*	*8700*
2021	*2550*	*2000*	*2250*	*2150*	*8950*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.82	.72	.82	.75	3.11
2018	.85	.76	.91	.73	3.25
2019	.97	.74	.98	.76	3.45
2020	*1.03*	*.80*	*.97*	*.85*	*3.65*
2021	*1.08*	*.85*	*1.02*	*.90*	*3.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.445	.445	.445	.445	1.78
2017	.475	.475	.475	.475	1.90
2018	.505	.505	.505	.505	2.02
2019	.535	.535	.535	.535	2.14
2020	.5675				

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.2 mill. electric, 540,000 gas, 229,000 water customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to 3/4 of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts; supplies water to CT, MA, & NH. Acq'd NSTAR 4/12; Aquation 12/17. Electric rev. breakdown: residential, 54%; commercial, 37%; industrial, 5%; other, 4%. Fuel costs: 36% of revs. '19 reported deprec. rate: 3.0%. Has 8,200 empls. Chairman, Pres. & CEO: James J. Judge. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource has agreed to pay $1.1 billion iu cash for a gas utility in Massachusetts. Columbia Gas, owned by NiSource, has 330,000 customers. The deal requires the approval of the Massachusetts regulators and is expected to be completed by the end of the third quarter. Eversource plans to finance this with a combination of debt and common equity. The company expects the acquisition to be accretive to earnings in the first 12 months after closing. We will not adjust our figures to reflect the deal until after it is completed. Note that NiSource will be responsible for any liabilities resulting from an explosion in September of 2018.

Two rate cases are pending. P.S. of New Hampshire filed for an electric increase of $70.4 million, based on a return on equity of 10.4% and a common-equity ratio of 54.85%. PSNH has been collecting interiu rates of $28.3 million since July 1, 2019. New rates are expected to take effect on July 1st. NSTAR Gas asked the Massachusetts commission for an increase of $38 million, based on an ROE of 10.45% and a common-equity ratio of 54.85%. Its application also requested a regulatory mechanism to provide a yearly performance-based ratemaking increase. New tariffs are expected to take effect on October 1st.

We look for earnings growth iu 2020 aud 2021 in line with Eversource's annual target of 5%-7%. The company should benefit from rate relief at its utilities and growth in its transmission rate base. Any sales decline stemming from the weak economy should have little effect on Eversource because most of its utilities operate under regulatory mechanisms that decouple revenues and volume. It's possible that the Federal Energy Regulatory Commission will lower the allowed ROE for transmission, forcing Eversource to refund previously collected revenues.

Three offshore wind projects are under development. These would add 1,714 megawatts of capacity from 2022 through 2024, and might well enable earnings growth to accelerate in 2024. However, there is significant construction risk.

This timely stock has fallen just 5% in 2020. Thus, the yield is low for a utility, and total return potential is unappealing for the 18-month and 2023-2025 periods.

Paul E. Debbas, CFA *May 15, 2020*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢; '19, (64¢). Next earnings report due early Aug. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '19: $28.16/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: (elec.) '18, 10.0%; (gas) '16, 9.8%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '10, 9.67%; earned on avg. com. eq., '19: 9.2%. Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	70
Earnings Predictability	95

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EXELON CORP. NDQ-EXC

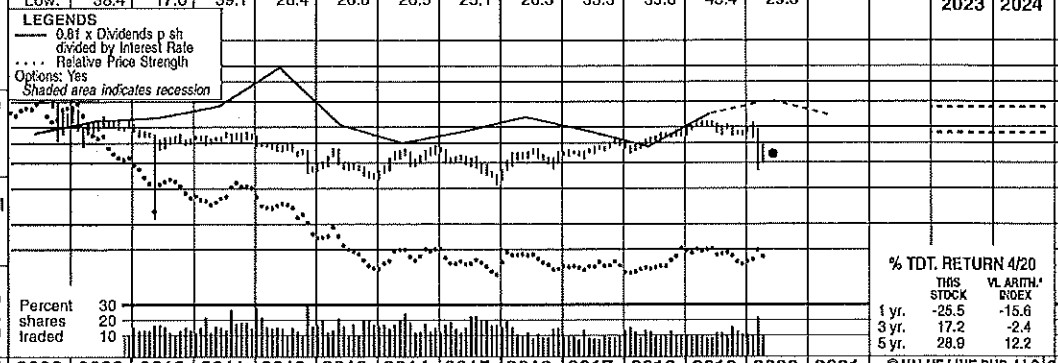
RECENT PRICE 35.45 | P/E RATIO 14.8 (Trailing: 11.8 Median: 15.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Lowered 6/7/19
SAFETY 3 Lowered 5/15/20
TECHNICAL 3 Raised 5/8/20
BETA .90 (1.00 = Market)

High:	59.0	49.9	45.4	43.7	37.8	38.9	38.3	37.7	42.7	47.4	51.2	50.5	
Low:	38.4	17.0	39.1	28.4	26.6	28.5	25.1	26.3	33.3	35.6	43.4	29.3	

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.81 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$29-$61	$45 (25%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+70%)	18%
Low	45	(+25%)	10%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	429	423	428
to Sell	464	451	478
Hld's(000)	774543	767278	768153

% TDT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-25.5	-15.6
3 yr.	17.2	-2.4
5 yr.	28.9	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
21.65	23.05	23.37	28.62	28.65	26.25	28.17	28.53	27.48	29.03	31.90	32.01	33.94	34.81	37.17	35.39	*34.85*	*36.75*	Revenues per sh	*42.50*
5.68	6.19	6.71	7.43	7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	7.01	8.37	8.24	8.96	*8.65*	*9.55*	"Cash Flow" per sh	*11.00*
2.75	3.21	3.50	4.03	4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	1.80	2.78	2.07	3.01	*2.40*	*3.00*	Earnings per sh A	*3.50*
1.26	1.60	1.64	1.82	2.05	2.10	2.10	2.10	2.10	1.46	1.24	1.24	1.26	1.31	1.38	1.45	*1.53*	*1.61*	Div'd Decl'd per sh B ■	*1.90*
2.89	3.25	3.61	4.05	4.74	4.96	5.03	6.09	6.77	6.29	7.07	8.29	9.26	7.87	7.84	7.45	*8.60*	*7.15*	Cap'l Spending per sh	*7.25*
14.19	13.69	14.89	15.34	16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	27.96	30.99	31.77	33.12	*34.05*	*35.50*	Book Value per sh C	*40.25*
664.19	666.37	669.86	660.88	658.15	659.76	661.85	663.37	854.78	857.29	859.83	919.92	924.04	953.34	968.19	973.00	*976.00*	*979.00*	Common Shs Outst'g D	*990.00*
13.0	15.4	16.5	18.2	18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	18.7	13.4	20.1	15.7	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.69	.82	.89	.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.98	.67	1.09	.84	*Value Line*		Relative P/E Ratio	*.80*
3.5%	3.2%	2.8%	2.5%	2.6%	4.3%	4.9%	5.0%	5.7%	4.7%	3.7%	3.9%	3.7%	3.5%	3.3%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $37799 mill. Due in 5 Yrs $13136 mill.
LT Debt $31719 mill. LT Interest $1379 mill.
Includes $390 mill. nonrecourse transition bonds.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $287 mill.

Pension Assets-12/19 $18590 mill. Oblig $22868 mill.

Pfd Stock None

Common Stock 974,319,565 shs. as of 1/31/20

MARKET CAP: $35 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
18644	18924	23489	24888	27429	29447	31360	33531	35985	34438	*34000*	*36000*	Revenues ($mill)	*42000*
2567.0	2499.0	1579.0	1999.0	1826.0	2282.0	1677.0	2636.0	2010.0	2936.0	*2340*	*2950*	Net Profit ($mill)	*3520*
39.2%	36.8%	32.4%	36.5%	27.2%	32.2%	38.5%	34.2%	5.4%	19.4%	*19.5%*	*19.5%*	Income Tax Rate	*19.5%*
2.1%	3.0%	5.8%	4.5%	5.5%	5.4%	12.3%	6.5%	7.0%	5.3%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
46.8%	45.7%	45.8%	44.4%	46.7%	48.3%	55.5%	52.2%	52.8%	49.6%	*51.0%*	*49.0%*	Long-Term Debt Ratio	*50.0%*
52.9%	54.0%	53.5%	55.2%	52.8%	51.3%	44.5%	47.8%	47.2%	50.4%	*49.0%*	*51.0%*	Common Equity Ratio	*50.0%*
25651	26661	40057	41196	42811	50272	58053	62422	65229	63943	*67475*	*71225*	Total Capital ($mill)	*79600*
29941	32570	45186	47330	52087	57439	71555	74202	76707	80233	*83025*	*81225*	Net Plant ($mill)	*86200*
11.4%	10.6%	5.1%	5.9%	5.3%	5.5%	4.1%	5.3%	4.2%	5.7%	*5.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
18.8%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	*7.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
18.9%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	*7.0%*	*9.0%*	Return on Com Equity E	*9.0%*
8.7%	7.7%	NMF	3.2%	3.3%	4.5%	1.9%	4.7%	2.2%	4.7%	*2.5%*	*4.5%*	Retained to Com Eq	*4.0%*
54%	56%	109%	63%	59%	49%	70%	47%	66%	48%	*57%*	*49%*	All Div'ds to Net Prof	*52%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-3.0	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	NA	NA
Fixed Charge Cov. (%)	282	236	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	2.5%	4.0%	*3.0%*
"Cash Flow"	1.0%	5.0%	*4.5%*
Earnings	-4.5%	4.5%	*5.0%*
Dividends	-3.5%	-3.0%	*5.5%*
Book Value	6.5%	4.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	8757	7623	8769	8382	33531
2018	9693	8076	9403	8813	35985
2019	9477	7689	8929	8343	34438
2020	*9450*	*7450*	*8800*	*8300*	*34000*
2021	*9950*	*8000*	*9350*	*8700*	*36000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.83	.44	.95	.56	2.78
2018	.60	.56	.76	.16	2.07
2019	.93	.50	.79	.79	3.01
2020	*.50*	*.50*	*.75*	*.65*	*2.40*
2021	*.85*	*.60*	*.90*	*.65*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.31	.318	.318	.318	1.26
2017	.328	.328	.328	.328	1.31
2018	.345	.345	.345	.345	1.38
2019	.362	.362	.363	.363	1.45
2020	.383				

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, PECO Energy, Baltimore Gas and Electric, Pepco, Delmarva Power, & Atlantic City Electric. Has 8.9 mill. elec., 1.3 mill. gas customers. Has nonregulated generating & energy-marketing ops. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. rev. breakdown: res'l, 54%; small comm'l & ind'l, 16%; large comm'l & ind'l, 17%; other, 13%. Generating sources: nuclear, 65%; other, 10%; purch., 25%. Fuel costs: 45% of revs. '19 depr. rates: 2.8%-7.4% elec., 2.0% gas. Has 32,700 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon stock continues to underperform most electric utility equities. The equity turned in a poor showing in 2019, with a 4.2% total return versus the industry median of 25.1%. So far in 2020, the stock price has fallen 22%, even more than most utility issues. Investors have been concerned about federal subpoenas Exelon and its Commonwealth Energy subsidiary received in 2019 about the company's lobbying activities in Illinois. The SEC opened a similar investigation last year. What's more, business conditions have gotten worse. The poor economy is hurting Exelon's utilities that don't operate under regulatory mechanisms that decouple revenues and volume. The company's power-generating subsidiary is experiencing low prices—wholesale electricity rates typically track natural gas prices—and weak demand. This operation has been reducing expenses, but this won't be enough to offset the difficult industrywide conditions.

We have slashed our 2020 earnings estimate by $0.75 a share. Besides the problems mentioned above, first-quarter profits (which were released shortly after this report went to press) were hurt by unrealized losses on the company's nuclear decommissioning trusts, which resulted from the poor stock-market performance in the period. We also lowered our 2021 estimate by $0.25 a share, based on our assumption that the prospects for the nonregulated operations will be less favorable than we expected in our February report.

Exelon's utilities have been improving their results. Rate relief enabled their earned ROE, as a group, to rise to 10.0% at year-end 2019 from 9.6% a year earlier. Pepco and Delmarva have electric rate cases pending in the District of Columbia and Maryland, respectively, with orders expected later this year. Whether the utility operations can still meet the company's goal of 6%-8% annual earnings growth through 2023 remains to be seen.

We advise investors to look elsewhere. In our view, the dividend yield, although above the utility average, is not high enough to compensate investors for the poor market conditions and legal risks Exelon faces. We have lowered the Financial Strength rating and Safety rank a notch each, to B+ and 3 (Average), respectively.

Paul E. Debbas, CFA *May 15, 2020*

(A) Diluted egs. Excl. nonrec. gain (losses): '05, ($1.85); '06, ($1.15); '09, (20¢); '12, (50¢); '13, (31¢); '14, 23¢; '16, (58¢); '17, $1.19. '18 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. deferred charges. In '19: $15.43/sh. (D) In mill. (E) Rate all'd on com. eq. in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; in NJ in '16: 9.75%; earned on avg. com. eq., '19: 9.3%. Regulatory Climate: PA, NJ Avg.; IL, MD, Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	55

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FIRSTENERGY NYSE-FE

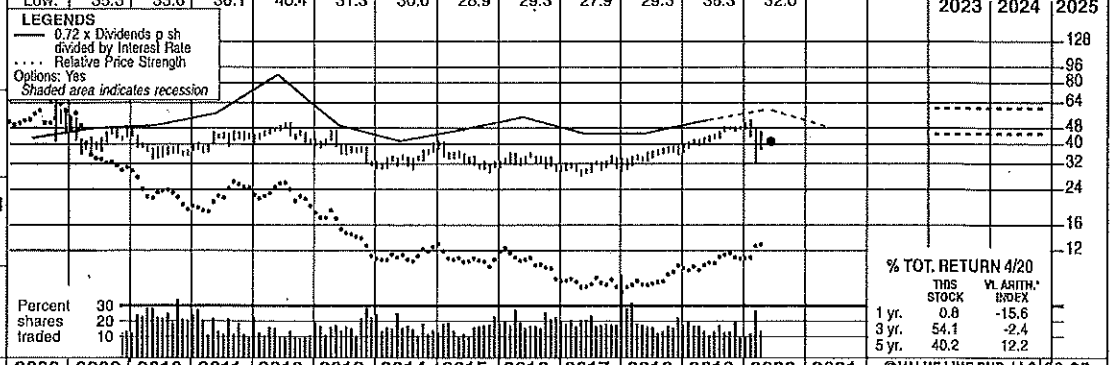
RECENT PRICE 41.19 | P/E RATIO 22.3 (Trailing: 33.2 Median: 19.0) | RELATIVE P/E RATIO 1.34 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Lowered 6/7/19
SAFETY 2 Raised 6/17/18
TECHNICAL 1 Raised 5/15/20
BETA .85 (1.00 = Market)

High:	53.6	47.8	46.5	51.1	46.8	40.8	41.7	36.6	35.2	39.9	49.1	52.5
Low:	35.3	33.6	36.1	40.4	31.3	30.0	28.9	29.3	27.9	29.3	36.3	32.0

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.72 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$36-$72	$54 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+45%)	13%
Low	45	(+10%)	6%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	320	301	333
to Sell	271	279	264
Hld's(000)	524158	495950	465497

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.8	-15.6
3 yr.	54.1	-2.4
5 yr.	40.2	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
37.76	36.35	36.03	42.00	44.70	41.70	43.76	38.87	36.57	35.60	35.74	35.48	32.92	31.49	22.00	20.41	*20.25*	*21.05*	Revenues per sh	*22.50*
7.60	7.55	7.22	8.34	9.04	8.80	8.50	5.75	6.05	6.30	4.55	6.33	6.53	6.54	3.98	3.94	*3.90*	*4.90*	"Cash Flow" per sh	*5.50*
2.77	2.84	3.82	4.22	4.38	3.32	3.25	1.68	2.13	2.97	.85	2.00	2.10	2.73	1.33	1.84	*1.85*	*2.75*	Earnings per sh A	*3.25*
1.91	1.71	1.85	2.05	2.20	2.20	2.20	2.20	2.20	1.65	1.44	1.44	1.44	1.44	1.82	1.53	*1.57*	*1.61*	Div'd Decl'd per sh B ■	*1.90*
2.57	3.66	4.12	5.36	9.47	7.23	6.44	5.45	7.09	6.90	8.42	6.83	6.93	6.38	5.23	4.93	*5.50*	*5.75*	Cap'l Spending per sh	*5.50*
26.04	27.86	28.30	29.45	27.17	28.08	28.03	31.75	31.29	30.32	29.49	29.33	14.11	8.81	13.17	12.90	*13.40*	*14.65*	Book Value per sh C	*20.25*
329.84	329.84	319.21	304.84	304.84	304.84	304.84	418.22	418.22	418.63	421.10	423.56	442.34	445.33	511.92	540.65	*543.00*	*546.00*	Common Shs Outst'g D	*575.00*
14.1	16.1	14.2	15.6	15.6	13.0	11.7	22.4	21.1	13.1	NMF	17.0	15.9	11.4	26.5	23.8	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.74	.86	.77	.83	.94	.87	.74	1.41	1.34	.74	NMF	.86	.83	.57	1.43	1.28	*Value Line*		Relative P/E Ratio	*.85*
4.9%	3.7%	3.4%	3.1%	3.2%	5.1%	5.8%	5.2%	4.9%	4.3%	4.3%	4.2%	4.3%	4.6%	5.2%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $21952 mill. Due in 5 Yrs $5922 mill.
LT Debt $20821 mill. LT Interest $944 mill.
Incl. $40 mill. capitalized leases.
(LT interest earned: 2.1x)
Leases, Uncapitalized Annual rentals $40 mill.

Pension Assets-12/19 $8395 mill. Oblig $11050 mill.

Pfd Stock None

Common Stock 541,753,695 shs.

MARKET CAP: $22 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
13339	16258	15294	14903	15049	15029	14562	14022	11261	11035	*11000*	*11500*	Revenues ($mill)	*13000*
991.0	752.0	891.0	1245.0	356.0	844.0	892.0	1213.0	726.0	995.0	*1000*	*1510*	Net Profit ($mill)	*1815*
38.6%	41.3%	41.1%	36.1%	5.6%	35.7%	37.8%	37.2%	32.4%	19.0%	*22.5%*	*22.5%*	Income Tax Rate	*22.5%*
16.6%	9.3%	8.1%	6.0%	33.1%	13.9%	11.5%	6.5%	9.0%	7.1%	*7.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
59.5%	54.2%	53.7%	55.5%	60.7%	60.7%	74.5%	84.3%	72.3%	73.8%	*75.0%*	*73.0%*	Long-Term Debt Ratio	*66.0%*
40.5%	45.8%	46.3%	44.5%	39.3%	39.3%	25.5%	15.7%	27.4%	26.2%	*25.0%*	*27.0%*	Common Equity Ratio	*34.0%*
21124	28996	28263	28523	31596	31613	24433	25040	24565	26593	*29000*	*29475*	Total Capital ($mill)	*34900*
19788	30337	32903	33252	35783	37214	29387	28879	29911	31650	*33575*	*35600*	Net Plant ($mill)	*41200*
6.3%	4.0%	4.9%	6.0%	2.7%	4.3%	5.7%	7.0%	4.9%	5.4%	*5.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
11.6%	5.7%	6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	10.7%	14.3%	*14.0%*	*19.0%*	Return on Shr. Equity	*15.5%*
11.6%	5.7%	6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	9.7%	14.2%	*14.0%*	*19.0%*	Return on Com Equity E	*15.5%*
3.8%	NMF	NMF	2.6%	NMF	1.9%	4.5%	14.6%	NMF	2.5%	*2.0%*	*8.0%*	Retained to Com Eq	*6.0%*
68%	117%	103%	74%	NMF	72%	68%	53%	108%	82%	*85%*	*58%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.1	+4.2	-2.7
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.4	+.3
Fixed Charge Cov. (%)	249	199	249

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-5.5%	-7.5%	*-1.5%*
"Cash Flow"	-6.0%	-3.0%	*2.0%*
Earnings	-7.0%	--	*8.5%*
Dividends	-3.0%	-2.0%	*3.0%*
Book Value	-8.5%	-17.5%	*9.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	3557	3309	3714	3442	14022
2018	2862	2625	3064	2710	11261
2019	2883	2516	2963	2673	11035
2020	2709	*2591*	*3000*	*2700*	*11000*
2021	*2900*	*2700*	*3100*	*2800*	*11500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.71	.59	.95	.47	2.73
2018	.01	.27	.66	.34	1.33
2019	.66	.63	.75	d.20	1.84
2020	.05	*.50*	*.75*	*.55*	*1.85*
2021	*.70*	*.70*	*.80*	*.55*	*2.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.36	.36	.36	.36	1.44
2017	.36	.36	.36	.36	1.44
2018	.36	.36	.36	.36	1.44
2019	.38	.38	.38	.38	1.52
2020	.39				

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to 6.1 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown: residential, 61%; commercial, 25%; industrial, 13%; other, 1%. Purchases most of its power. Fuel costs: 31% of revenues. '19 reported deprec. rate: 2.7%. Has 12,300 employees. Chairman: George M. Smart. President & CEO: Charles E. Jones. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy's utility in New Jersey filed a general rate case. Jersey Central Power & Light is seeking a rate increase of $186.9 million (7.8%), based on a return on equity of 10.15% and a common-equity ratio of 52.8%. Included in the utility's application is a request to recover storm-related costs that have been deferred. Resolution of the case is not expected until 2021, even if a settlement is reached.

Investors should not be alarmed by the company's depressed first-quarter earnings. Our earnings presentation *includes* mark-to-market adjustments associated with FirstEnergy's pension and non-pension benefits plans. This happens in the fourth quarter every year, and there was an additional adjustment in the March period associated with a former subsidiary. This resulted in a pretax charge of $423 million. We think share net will wind up approximating the 2019 tally.

FirstEnergy is well positioned to handle a slump in kilowatt-hour sales stemming from the weak economy. About one-third of corporate profits comes from the transmission business, on which the company earns a return through a forward-looking ratemaking process. Investment here will continue ($1.20 billion-$1.45 billion annually) as old equipment is replaced. The company's Ohio business (20% of its distribution sales) operates under a regulatory mechanism that decouples revenues and volume. Finally, most of FirstEnergy's revenues from commercial and industrial customers comes from demand and customer charges that are not based on volume.

We expect much higher profits in 2021. Without the aforementioned charge for the pension adjustment, first-quarter results should return to a normal level. We also assume reasonable rate treatment in the JCP&L rate case. And transmission investment will be ongoing.

FirstEnergy stock has an average dividend yield for a utility. The stock price is down 15% this year, in line with most utilities. Also like most utilities, total return potential doesn't stand out for the 18-month or 3- to 5-year period. As stated, the weak economy is not a big hindrance, and coronavirus is not a significant investment consideration.

Paul E. Debbas, CFA *May 15, 2020*

(A) Dil. EPS. Excl. nonrec. losses: '13, $2.07; '14, 17¢; '15, 63¢; '16, $16.59; '17, $6.61; gains (loss) from disc. ops.: '14, 20¢; '18, 66¢; '19, (17¢); '20, 9¢. '17, '18 EPS don't sum due to rounding or chg. in shs. Next egs. due late July. (B) Div'ds pd. early Mar., June, Sept., & Dec. 5 div'ds in '04 & '18, 3 in '13. ■ Div'd reinv. avail. (C) Incl. intang. In '19: $10.57/sh. (D) In mill. (E) Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.75%-11.7%; earned avg. com. eq., '19: 14.0%. Reg. Climate: OH Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	40

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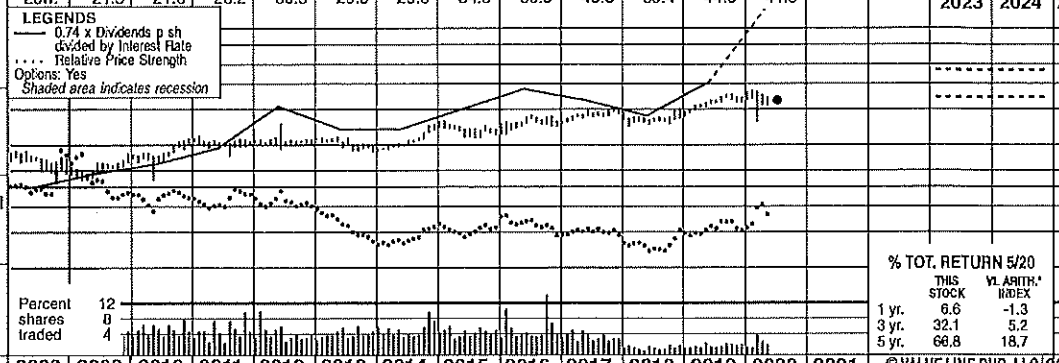
FORTIS INC. TSE-FTS.TO [A]

RECENT PRICE 53.13 | P/E RATIO 21.7 (Trailing: 20.4 Median: 19.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 2 Lowered 5/22/20
SAFETY 2 Raised 7/17/15
TECHNICAL 2 Lowered 6/5/20
BETA .80 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
High:	29.2	34.5	35.4	40.7	35.1	40.5	42.1	45.1	48.7	47.4	56.9	59.3
Low:	21.5	21.6	28.2	30.5	29.6	29.8	34.5	36.0	40.6	39.4	44.0	41.6

LEGENDS
— 0.74 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$43-$86	$65 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+40%)	12%
Low	55	(+5%)	5%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	134	133	120
to Sell	108	118	131
Hld's(000)	228513	245710	238041

Percent shares traded 12 8 4

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.6	-1.3
3 yr.	32.1	5.2
5 yr.	66.8	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
11.99	13.86	14.14	17.48	23.07	21.24	21.01	19.84	19.07	18.99	19.57	23.69	17.03	19.71	19.58	18.96	*18.45*	*19.00*	Revenues per sh	*20.75*
2.23	2.73	3.05	2.96	3.51	3.66	3.99	3.90	4.10	4.10	3.62	5.21	3.91	5.43	5.40	5.44	*5.55*	*5.90*	"Cash Flow" per sh	*6.75*
1.01	1.19	1.36	1.29	1.52	1.51	1.62	1.74	1.65	1.63	1.38	2.11	1.89	2.66	2.52	2.68	*2.45*	*2.60*	Earnings per sh B	*2.75*
.54	.59	.67	.82	1.00	1.04	1.12	1.17	1.21	1.25	1.30	1.43	1.55	1.65	1.75	1.86	*1.97*	*2.08*	Div'd Decl'd per sh C ■	*2.50*
2.92	4.93	4.80	5.16	5.34	5.79	5.89	5.91	5.68	5.32	6.00	7.97	5.13	7.18	7.51	8.03	*9.30*	*8.00*	Cap'l Spending per sh	*6.75*
10.47	11.76	12.26	16.72	18.00	18.57	18.95	20.53	20.84	22.39	24.90	28.63	32.32	31.77	34.80	36.49	*37.60*	*39.15*	Book Value per sh D	*43.25*
95.53	103.20	104.09	155.52	169.19	171.26	174.39	188.83	191.57	213.17	276.00	281.56	401.49	421.10	428.50	463.30	*466.00*	*469.00*	Common Shs Outst'g E	*478.00*
15.3	17.2	17.7	21.1	17.5	16.4	18.2	18.8	20.1	20.0	24.3	18.0	21.6	16.8	17.1	19.2	*Bold figures are*		Avg Ann'l P/E Ratio	*24.0*
.81	.92	.96	1.12	1.05	1.09	1.16	1.18	1.28	1.12	1.28	.91	1.13	.84	.92	1.03	*Value Line*		Relative P/E Ratio	*1.35*
3.5%	2.9%	2.8%	3.0%	3.8%	4.2%	3.8%	3.6%	3.6%	3.8%	3.9%	3.6%	3.6%	3.7%	4.1%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $25146 mill. Due in 5 Yrs $5906 mill.
LT Debt $23445 mill. LT Interest $961 mill.
Incl. $334 mill. capitalized leases.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $10 mill.

Pension Assets-12/19 $3208 mill.
Oblig $3632 mill.
Pfd Stock $1623 mill. Pfd Div'd $67 mill.

Common Stock 464,300,000 shs.
as of 5/5/20
MARKET CAP: $25 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
3664.0	3747.0	3654.0	4047.0	5401.0	6727.0	6836.0	8301.0	8390.0	8783.0	*8600*	*8900*	Revenues ($mill)	*9900*
313.0	347.0	362.0	390.0	374.0	672.0	660.0	1174.0	1136.0	1238.0	*1335*	*1405*	Net Profit ($mill)	*1545*
17.2%	18.3%	14.1%	7.4%	14.6%	21.3%	16.9%	25.8%	13.4%	12.5%	*14.0%*	*14.0%*	Income Tax Rate	*14.0%*
4.2%	5.5%	5.0%	5.9%	7.2%	7.4%	10.0%	9.5%	8.4%	9.2%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
60.5%	57.5%	55.1%	53.5%	54.8%	53.3%	59.3%	58.4%	58.8%	54.2%	*53.5%*	*53.5%*	Long-Term Debt Ratio	*52.5%*
33.5%	36.9%	35.1%	37.0%	35.7%	38.1%	36.2%	37.1%	37.2%	41.8%	*42.5%*	*43.0%*	Common Equity Ratio	*44.0%*
9868.0	10513	11358	12892	19235	21151	35874	36108	40082	40445	*41325*	*42950*	Total Capital ($mill)	*46800*
8762.0	9281.0	10249	12267	17816	19595	29337	29668	32654	33988	*36875*	*39075*	Net Plant ($mill)	*44500*
5.0%	5.0%	4.8%	4.6%	3.4%	4.5%	2.8%	4.5%	4.1%	4.4%	*4.5%*	*4.5%*	Return on Total Cap'l	*4.5%*
8.0%	7.8%	7.1%	6.5%	4.3%	6.8%	4.5%	7.8%	6.9%	6.7%	*6.5%*	*6.5%*	Return on Shr. Equity	*6.5%*
8.6%	8.2%	7.9%	7.0%	4.5%	7.4%	4.5%	8.3%	7.2%	6.9%	*6.5%*	*6.5%*	Return on Com Equity F	*6.5%*
2.8%	4.3%	3.7%	3.2%	1.7%	4.5%	2.1%	5.2%	4.1%	4.0%	*3.0%*	*3.0%*	Retained to Com Eq	*2.5%*
71%	52%	60%	61%	68%	46%	59%	41%	46%	45%	*50%*	*50%*	All Div'ds to Net Prof G	*55%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	231	208	204

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-.5%	--	*1.0%*
"Cash Flow"	5.0%	6.5%	*3.5%*
Earnings	6.0%	11.0%	*1.0%*
Dividends	6.5%	7.0%	*6.0%*
Book Value	7.0%	8.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2274	2015	1901	2111	8301
2018	2197	1947	2040	2206	8390
2019	2436	1970	2051	2326	8783
2020	2391	*1859*	*2050*	*2300*	*8600*
2021	*2450*	*2000*	*2100*	*2350*	*8900*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.72	.62	.66	.66	2.66
2018	.69	.57	.65	.61	2.52
2019	.72	.54	.63	.77	2.68
2020	.67	*.55*	*.63*	*.60*	*2.45*
2021	*.72*	*.61*	*.66*	*.61*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.375	.375	.375	.40	1.53
2017	.40	.40	.40	.425	1.63
2018	.425	.425	.425	.45	1.73
2019	.45	.45	.45	.4775	1.83
2020	.4775	.4775			

BUSINESS: Fortis Inc.'s main focus is electricity, hydroelectric, and gas utility operations (both regulated and nonregulated) in the United States, Canada, and the Caribbean. Has 2 mill. electric, 1.3 mill. gas customers. Owns UNS Energy (Arizona), Central Hudson (New York), FortisBC Energy (British Columbia), FortisAlberta (Central Alberta), and Eastern Canada (Newfoundland). Sold commercial real estate and hotel property assets in 2015. Acquired ITC Holdings 10/16. Fuel costs: 29% of revenues. '19 reported deprec. rate: 2.6%. Has 9,000 employees. Chairman: Douglas J. Haughey. President & CEO: Barry V. Perry. Inc.: Canada. Address: Fortis Place, Suite 1100, 5 Springdale St., PO Box 8837, St. John's, NL, Canada, A1B 3T2. Tel.: 709-737-2800. Internet: www.fortisinc.com.

Fortis is better positioned than most utilities to deal with the effects of the weak economy. The company's ITC transmission subsidiary and FortisAlberta do not depend on retail electric volume for their revenues, and thns aren't affected by declines in kilowatt-hour sales. This represents about 63% of Fortis' business. Of the remaining 37%, 19% comes from residential kilowatt-honr sales (which are benefiting from stay-at-home orders) and 18% comes from commercial and indnstrial volume, which is down sharply.

Tucson Electric Power's rate proceedings have heen delayed. The utility is seeking a $99 million hike, based on a 10% return on equity and a 53% common-equity ratio. TEP was expecting to get rate relief around mid-2020, but due to disruptions to normal operations stemming from the coronavirus, the schedule was delayed 60 days. A ruling from the Arizona commission is expected by yearend.

A decline in profits is likely this year. The fourth-quarter comparison will be difficult because a reversal of a reserve ITC had taken for an expected revenue refund added $0.19 a share to the bottom line. Also, average shares outstanding will be much higher due to a stock sale in late 2019. The aforementioned delay in the TEP rate order is another negative factor. At least a favorable swing in exchange rates between the United States and Canadian dollars is a positive factor.

We think the board of directors will raise the dividend, effective with the October paymcnt. This has been the pattern in recent years. Fortis' goal is 6% yearly dividend growth through 2024, and the increase we estimate ($0.11 a share annually) would produce a 5.8% hike.

Timely Fortis stock has outperformed most electric utility issues in 2020. The price is down just 1%. We attribute this to the significant proportion of the company's business that is insulated from declines in kilowatt-hour sales. This is a change from recent years, when Fortis traded at a disconnt to most utilities because its Canadian business earns a lower return on investment than U.S. utilities earn. The dividend yield is about average for a utility. Total return potential is decent for the 18-month span but not for 2023-2025.

Paul E. Debbas, CFA *June 12, 2020*

(A) Also trades on NYSE under the symbol FTS. All data in Canadian $. (B) Dil. egs. Excl. nonrecur. gains (loss): '07, 3¢; '14, 2¢; '15, 48¢; '17, (35¢); '18, 7¢. '19, $1.12. '19 EPS don't sum due to chng. in shs. Next egs. report due early Aug. (C) Div'ds histor. paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. (D) Incl. intang. In '19: $35.01/sh. (E) In mill. (F) Rates all'd on com. eq.: 8.3%-10.32%; earn. on avg. com. eq., '19: 7.6%. Regul. Clim.: FERC, Above Avg.; AZ, Avg.; NY, Below Avg. (G) Excl. div'ds paid through reinvest. plan.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	70

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GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE NMF | P/E RATIO NMF (Trailing: NMF Median: 17.0) | RELATIVE P/E RATIO NMF | DIV'D YLD Nil | VALUE LINE

TIMELINESS — Suspended 7/21/17
SAFETY 3 Lowered 12/26/08
TECHNICAL — Suspended 7/21/17
BETA .70 (1.00 = Market)

High:	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3	32.7	34.7	34.4	
Low:	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.0	24.1	25.8	26.7	28.5	

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.66 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High		See	
Low		Text	

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	2	0	0	10	0
to Sell	0	6	0	0	0	0	0	0	0

Institutional Decisions

	3Q2017	4Q2017	1Q2018
to Buy	177	136	156
to Sell	166	159	168
Hld's(000)	211734	188292	194146

Percent shares traded 30 20 10

% TOT. RETURN 5/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.2	14.3
3 yr.	45.3	29.1
5 yr.	80.7	67.5

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	16.21	12.43	12.56			Revenues per sh	
4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	3.98	3.35	2.10			"Cash Flow" per sh	
2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	1.37	1.61	d.06	See	See	Earnings per sh A	See
1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	1.00	1.06	1.10	Text	Text	Div'd Decl'd per sh B ■	Text
1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	4.42	2.86	2.69			Cap'l Spending per sh	
13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	23.68	24.73	23.02			Book Value per sh C	
69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	154.40	215.35	215.66			Common Shs Outst'g D	
11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	19.4	18.0	NMF			Avg Ann'l P/E Ratio	
.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87	.98	.94	NMF			Relative P/E Ratio	
7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%	3.8%	3.6%	3.6%			Avg Ann'l Div'd Yield	

CAPITAL STRUCTURE as of 3/31/18
Total Debt $4336.4 mill. Due in 5 Yrs $2199.6 mill.
LT Debt $3608.5 mill. LT Interest $170.6 mill.
(LT interest earned: 2.2x)

Leases, Uncapitalized Annual rentals $12.9 mill.

Pension Assets-12/17 $848.4 mill. Oblig $1355.9 mill.

Pfd Stock None

Common Stock 215,795,884 shs.
as of 4/30/18
MARKET CAP: NMF

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	2502.2	2676.0	2708.2			Revenues ($mill)	
119.5	135.6	211.7	174.4	199.9	250.2	242.8	213.0	290.0	24.1			Net Profit ($mill)	
34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	36.7%	37.4%	NMF			Income Tax Rate	
46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	4.5%	4.6%	55.6%			AFUDC % to Net Profit	
49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	50.3%	35.3%	40.0%			Long-Term Debt Ratio	
49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	49.1%	55.9%	60.0%	See	See	Common Equity Ratio	See
5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	7440.6	9527.2	8277.4	Text	Text	Total Capital ($mill)	Text
6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	8662.4	8958.7	9124.7			Net Plant ($mill)	
3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	4.2%	3.9%	1.1%			Return on Total Cap'l	
4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	5.8%	4.7%	.5%			Return on Shr. Equity	
4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	5.8%	5.1%	NMF			Return on Com Equity E	
NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	1.6%	1.8%	NMF			Retained to Com Eq	
NMF	81%	54%	66%	63%	55%	60%	73%	67%	NMF			All Div'ds to Net Prof	

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.9	+.7	-1.6
Avg. Indust. Use (MWH)	1450	1500	1479
Avg. Indust. Revs. per KWH (¢)	6.96	7.29	7.68
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.9	+1.1	+1.3
Fixed Charge Cov. (%)	254	307	162

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-9.0%	-3.5%	
"Cash Flow"	-3.0%	-3.0%	See
Earnings	-6.5%	-6.5%	Text
Dividends	-4.5%	4.5%	
Book Value	3.5%	2.0%	

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	549.1	609.0	781.4	562.7	2502.2
2016	572.1	670.8	856.8	576.3	2676.0
2017	570.7	682.6	857.2	597.7	2708.2
2018	583.9	See			
2019		Text			

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.12	.28	.82	.15	1.37
2016	.17	.20	.86	.39	1.61
2017	d.11	d.10	.02	.14	d.06
2018	.16	See			
2019		Text			

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.23	.23	.23	.245	.94
2015	.245	.245	.245	.2625	1.00
2016	.2625	.2625	.2625	.275	1.05
2017	.275	.275	.275	.275	1.10
2018	.275				

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 867,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acquired Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 41%; industrial, 9%; other, 10%. Generating sources: coal, 53%; nuclear, 16%; other, 2%; purchased, 29%. Fuel costs: 22% of revenues. '17 reported depreciation rate (utility): 3.0%. Has 2,700 employees. Chairman, President & CEO: Terry Bassham. Incorporated: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Telephone: 816-556-2200. Internet: www.greatplainsenergy.com.

The merger of Great Plains Energy and Westar Energy was completed on June 4th. Great Plains stockholders received .5981 of a share of the combined company, Evergy (NYSE: EVRG), for each of their shares. For accounting purposes, Westar will be treated as the acquirer, so Evergy's 2018 results will include a full year of Westar's results and Great Plains' results from early June through yearend. This is our last report on Great Plains.

What does Evergy look like? The company's utility subsidiaries serve about 1.6 million customers in Missouri and Kansas. The utilities' contiguous service territories provide ample opportunities for reductions in operating and maintenance expenses. In fact, management projects that its O&M costs in 2021 will be 15% below the sum of Great Plains' and Westar's expenses in 2016. Evergy intends to pay an annual dividend of $1.84 a share, so this will not provide an immediate increase in dividend income for Great Plains' stockholders. The company also intends to repurchase some 60 million shares of stock in its first two years. Evergy's goals are annual earnings and dividend growth of 6%-8% and a payout ratio of 60%-70%. Our preliminary estimate of the company's 2019 earnings is a range of $2.65-$3.00 a share.

Some rate cases are pending. In Missouri, Kansas City Power & Light filed for an increase of $16.4 million (1.9%), based on a return of 9.85% on a common-equity ratio of 50%. Great Plains' Greater Missouri Operations requested a $19.3 million (2.6%) hike, based on a return of 9.85% on a common-equity ratio of 54.4%. In Kansas, KCP&L is seeking a $26.2 million hike, based on a return of 9.85% on a common-equity ratio of 49.8%. New tariffs in each of these cases are expected to take effect in late December.

A new regulatory law in Missouri will help. The law, effective on August 28th, will lessen the effects of regulatory lag and increase the ability of utilities to earn a reasonable return on their investment.

We advise Great Plains stockholders to retain their Evergy shares. The prospects of Evergy appear better than those that Great Plains had on a stand-alone basis. The new company is somewhat stronger financially, too.

Paul E. Debbas, CFA *June 15, 2018*

(A) Diluted earnings. Excl. nonrec. gains (losses): '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; '17, (61¢); gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '16 & '17 EPS don't sum due to rounding. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '17: $5.02/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in MO in '17: 9.5%; in KS in '15: 9.3%; earned on avg. com. eq., '17: NMF. Regulatory Climate: MO, Below Average; KS, Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	30

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HAWAIIAN ELECTRIC NYSE-HE

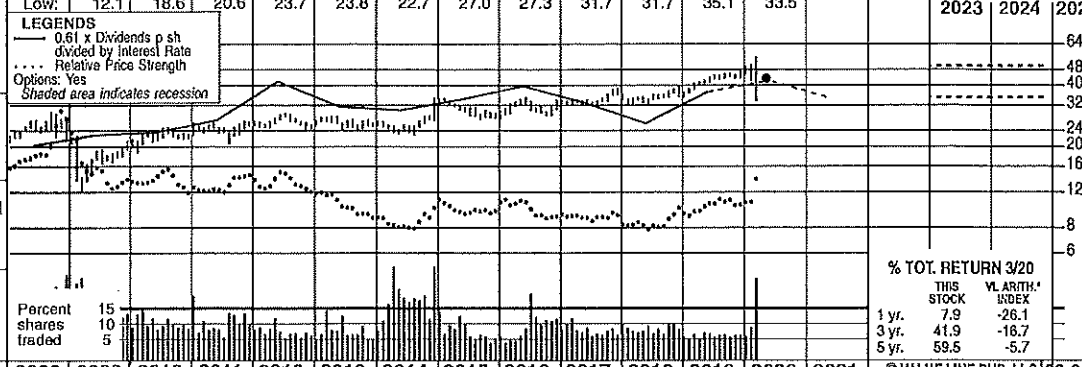
RECENT PRICE 43.43 | P/E RATIO 20.9 (Trailing: 21.7 Median: 18.0) | RELATIVE P/E RATIO 1.43 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 9/20/19
SAFETY 2 Raised 11/2/12
TECHNICAL 2 Raised 4/24/20
BETA .55 (1.00 = Market)

High:	22.7	25.0	26.8	29.2	28.3	35.0	34.9	35.0	38.7	39.3	47.6	55.2	
Low:	12.1	18.6	20.6	23.7	23.8	22.7	27.0	27.3	31.7	31.7	35.1	33.5	

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.61 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$37-$52	$45 (0%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	7%
Low	35	(-20%)	-1%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	145	120	143
to Sell	132	138	123
Hld's(000)	59312	60314	59966

Percent shares traded 15 10 5

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.9	-26.1
3 yr.	41.9	-16.7
5 yr.	59.5	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
23.85	27.36	30.21	30.40	35.56	24.96	28.14	33.76	34.46	31.98	31.59	24.22	21.92	23.49	26.28	26.38	*26.35*	*27.05*	Revenues per sh	*29.00*
3.09	3.22	3.19	3.01	2.72	2.59	2.88	3.18	3.28	3.22	3.41	3.31	4.17	3.68	4.20	4.55	*4.55*	*4.75*	"Cash Flow" per sh	*5.25*
1.36	1.46	1.33	1.11	1.07	.91	1.21	1.44	1.67	1.62	1.64	1.50	2.29	1.64	1.85	1.99	*1.95*	*2.05*	Earnings per sh A	*2.25*
1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.28	*1.32*	*1.36*	Div'd Decl'd per sh B ■	*1.60*
2.66	2.76	2.58	2.62	3.12	3.29	1.92	2.45	3.32	3.49	3.31	3.39	3.04	4.55	4.94	4.20	*4.10*	*4.30*	Cap'l Spending per sh	*4.50*
15.01	15.02	13.44	15.29	15.35	15.58	15.67	15.95	16.28	17.06	17.47	17.94	19.03	19.28	19.86	20.93	*21.75*	*22.60*	Book Value per sh C	*25.00*
80.69	80.98	81.46	83.43	90.52	92.52	94.69	96.04	97.93	101.26	102.57	107.46	108.58	108.79	108.88	108.97	*110.00*	*111.00*	Common Shs Outst'g D	*114.00*
19.2	18.3	20.3	21.6	23.2	19.8	18.6	17.1	15.8	16.2	15.9	20.4	13.6	20.7	18.9	21.3	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
1.01	.97	1.10	1.15	1.40	1.32	1.18	1.07	1.01	.91	.84	1.03	.71	1.04	1.02	1.15	*Value Line*		Relative P/E Ratio	*1.05*
4.8%	4.6%	4.6%	5.2%	5.0%	6.9%	5.5%	5.0%	4.7%	4.7%	4.8%	4.1%	4.0%	3.7%	3.5%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $2150.1 mill. Due in 5 Yrs $713.7 mill.
LT Debt $1862.4 mill. LT Interest $86.6 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $12.0 mill.
Pension Assets-12/19 $1779.2 mill.
Oblig $2278.3 mill.
Pfd Stock $34.3 mill. Pfd Div'd $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
Common Stock 108,973,328 shs. as of 2/13/20
MARKET CAP: $4.7 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
2665.0	3242.3	3375.0	3238.5	3239.5	2603.0	2380.7	2555.6	2860.8	2874.6	*2900*	*3000*	Revenues ($mill)	*3300*
115.4	140.1	164.9	163.4	170.2	161.8	250.1	180.6	203.7	219.8	*215*	*230*	Net Profit ($mill)	*260*
37.0%	35.1%	35.9%	34.0%	35.0%	36.5%	33.1%	34.7%	20.0%	19.0%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
7.4%	6.0%	6.9%	4.8%	5.5%	5.8%	4.6%	9.6%	7.7%	7.5%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
44.5%	44.9%	45.7%	44.0%	45.2%	43.5%	41.6%	43.4%	47.5%	44.6%	*47.0%*	*46.0%*	Long-Term Debt Ratio	*47.5%*
54.3%	53.9%	53.1%	55.0%	53.8%	55.5%	57.5%	55.7%	51.7%	54.6%	*52.0%*	*53.5%*	Common Equity Ratio	*52.0%*
2732.9	2841.3	3001.0	3142.9	3332.3	3473.5	3595.1	3765.5	4182.3	4176.9	*4585*	*4700*	Total Capital ($mill)	*5500*
3165.9	3334.5	3594.8	3858.9	4148.8	4377.7	4603.5	5025.9	4830.1	5109.6	*5270*	*5450*	Net Plant ($mill)	*5975*
5.6%	6.2%	6.7%	6.4%	6.2%	5.7%	7.9%	5.8%	5.9%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
7.6%	8.9%	10.1%	9.3%	9.3%	8.2%	11.9%	8.5%	9.3%	9.5%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
7.7%	9.0%	10.2%	9.4%	9.4%	8.3%	12.0%	8.5%	9.3%	9.6%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
1.4%	2.1%	4.2%	3.7%	2.3%	1.5%	6.3%	2.1%	3.1%	3.4%	*3.0%*	*3.0%*	Retained to Com Eq	*2.5%*
82%	78%	59%	61%	75%	83%	48%	76%	67%	64%	*67%*	*67%*	All Div'ds to Net Prof F	*71%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-1.8	--	+.6
Avg. Indust. Use (MWH)	5193	5067	5225
Avg. Indust. Revs. per KWH (¢)	22.56	25.76	25.52
Capacity at Yearend (Mw)	2224	2256	2254
Peak Load, Winter (Mw)	1584	1598	1601
Annual Load Factor (%)	65.8	65.0	65.2
% Change Customers (yr-end)	+.4	+.2	+.5
Fixed Charge Cov. (%)	409	361	368

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-2.0%	-5.0%	*2.0%*
"Cash Flow"	4.0%	4.5%	*4.0%*
Earnings	6.0%	2.0%	*3.5%*
Dividends	--	--	*4.0%*
Book Value	2.5%	3.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	591.5	632.3	673.2	658.6	2555.6
2018	645.9	685.3	768.0	761.6	2860.8
2019	661.6	715.5	771.5	726.0	2874.6
2020	*650*	*725*	*775*	*750*	*2900*
2021	*675*	*750*	*800*	*775*	*3000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.31	.36	.55	.42	1.64
2018	.37	.42	.60	.45	1.85
2019	.42	.39	.58	.61	1.99
2020	*.44*	*.43*	*.60*	*.48*	*1.95*
2021	*.45*	*.46*	*.63*	*.51*	*2.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.31	.31	.31	.31	1.24
2017	.31	.31	.31	.31	1.24
2018	.31	.31	.31	.31	1.24
2019	.32	.32	.32	.32	1.28
2020	.33				

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company, Inc. (HECO), American Savings Bank (ASB), and Pacific Current. HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 465,000 customers on O'ahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Elec. rev. breakdown: residential, 31%; commercial, 33%; lg. light & power, 35%; other, 1%. Generating sources: oil, 54%; purch., 46%. Fuel costs: 47% of revs. '19 reported depr. rate (util.): 3.2%. Has 3,800 employees. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

One of Hawaiian Electric Industries' utilities has a rate case pending, and another is upcoming. Hawaiian Electric Company, HEI's largest utility, filed for an increase of $77.6 million (4.1%), based on a return on equity of 10.5% and a common-equity ratio of 57.15%. The Public Utilities Commission (PUC) of Hawaii ordered a management audit of the utility, which is still on track to be completed in May. An interim order is due by July, but whether the coronavirus-related disruption to normal operations—and the effects of the worsening economy on customers—will affect the schedule is questionable. Maui Electric Company was planning to file a rate case in mid-2020, but again, whether this will be delayed remains to be seen.

Hawaii Electric Light Company is awaiting a final rate order. The utility had sought a $7.1 million hike and reached a settlement calling for a $2.8 million increase. However, the PUC denied the utility any interim rate relief. We are not optimistic that the final ruling will be any better. There is no due date for the final decision.

We trimmed our 2020 earnings estimate by a nickel a share. Our revised estimate of $1.95 a share remains within HEI's targeted range of $1.90-$2.10. However, management issued its guidance in mid-February, before the economy worsened. HEI's American Savings Bank subsidiary has been performing well (earning an ROE of 13.5% last year), and has good asset quality, but it is hard to envision a scenario in which a steep downturn in the economy won't affect the bank. The low interest-rate environment doesn't help, either. On the other hand, economic problems won't have much effect on HEI's utilities (except for an increase in bad-debt expense) because they operate under a regulatory mechanism that decouples revenues from volume. We expect an earnings recovery next year.

The board raised the dividend in the first quarter. The directors increased the quarterly payout by one cent a share (3.1%), as we had expected.

The stock lacks investor appeal. The dividend yield is below the utility mean, and total return potential is unattractive for the 18-month and 2023-2025 periods.

Paul E. Debbas, CFA *April 24, 2020*

(A) Diluted EPS. Excl. gain (loss) from disc. ops.: '04, 2¢; '05, (1¢); nonrec. gain (losses): '05, 11¢; '07, (9¢); '12, (25¢); '17, (12¢). '18 & '19 EPS don't sum due to rounding. Next egs. report due early May. (B) Div'ds pd. early Mar., June, Sept., & Dec. ■ Div'd reinv. avail. (C) Incl. intang. In '19: $7.03/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate allowed on com. eq. in '18: HECO, 9.5%; in '18: HELCO, 9.5%; in '18: MECO, 9.5%; earned on avg. com. eq., '19: 9.8%. Reg. Climate: Below Avg. (F) Excl. div'ds paid through reinv. plan.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	60

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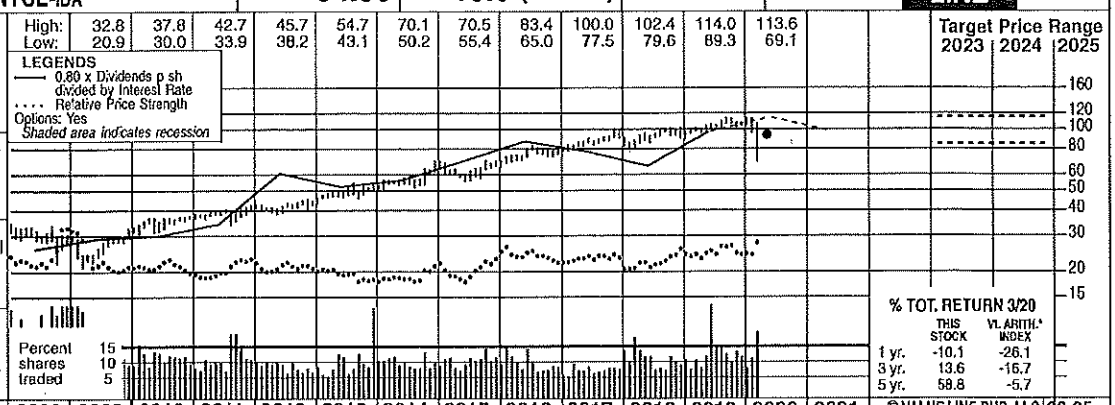
IDACORP, INC. NYSE-IDA

RECENT PRICE 94.30 | P/E RATIO 19.9 (Trailing: 20.5 Median: 16.0) | RELATIVE P/E RATIO 1.36 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 3/1/19
SAFETY 2 Raised 8/2/13
TECHNICAL 3 Raised 4/24/20
BETA .50 (1.00 = Market)

High:	32.8	37.8	42.7	45.7	54.7	70.1	70.5	83.4	100.0	102.4	114.0	113.6
Low:	20.9	30.0	33.9	38.2	43.1	50.2	55.4	65.0	77.5	79.6	89.3	69.1

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$89-$122	$106 (10%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+20%)	8%
Low	85	(-10%)	1%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	163	148	172
to Sell	149	165	157
Hld's(000)	38770	38815	39667

Percent shares traded 15 10 5

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-10.1	-26.1
3 yr.	13.6	-16.7
5 yr.	58.8	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	26.70	*27.30*	*28.25*	Revenues per sh	*30.75*
4.12	3.87	4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	8.07	*8.10*	*8.50*	"Cash Flow" per sh	*9.50*
1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	*4.55*	*4.75*	Earnings per sh A	*5.25*
1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	*2.73*	*2.93*	Div'd Decl'd per sh B ■ †	*3.55*
4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	5.53	*6.65*	*6.20*	Cap'l Spending per sh	*7.00*
23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	47.01	48.88	*50.65*	*52.40*	Book Value per sh C	*57.50*
42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	50.42	*50.40*	*50.40*	Common Shs Outst'g D	*50.40*
15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	22.3	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.21	*Value Line*		Relative P/E Ratio	*1.10*
4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/19
Total Debt $1836.4 mill. Due in 5 Yrs $250.0 mill.
LT Debt $1836.4 mill. LT Interest $85.4 mill.
(LT interest earned: 3.5x)

Pension Assets-12/18 $650.6 mill. Oblig $951.9 mill.

Pfd Stock None

Common Stock 50,409,901 shs. as of 2/14/20

MARKET CAP: $4.8 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
1036.0	1026.8	1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	*1375*	*1425*	Revenues ($mill)	*1550*
142.5	166.9	168.9	182.4	193.5	194.7	198.3	212.4	226.8	232.9	*230*	*240*	Net Profit ($mill)	*265*
--	--	13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
19.1%	23.3%	20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	*17.0%*	*17.0%*	AFUDC % to Net Profit	*16.0%*
49.3%	45.6%	45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	*46.0%*	*46.0%*	Long-Term Debt Ratio	*46.5%*
50.7%	54.4%	54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	*54.0%*	*54.0%*	Common Equity Ratio	*53.5%*
3020.4	3045.2	3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	*4740*	*4905*	Total Capital ($mill)	*5425*
3161.4	3406.6	3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	*4685*	*4810*	Net Plant ($mill)	*5250*
6.0%	6.8%	6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
5.5%	6.5%	5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	*3.5%*	*3.5%*	Retained to Com Eq	*3.0%*
41%	36%	41%	43%	46%	50%	53%	53%	54%	56%	*60%*	*61%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+2.6	+.1	-.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.83	5.64	5.32
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3422	3392	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.0	+2.3	+2.5
Fixed Charge Cov. (%)	329	309	307

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	2.5%	2.5%	*2.5%*
"Cash Flow"	5.5%	4.5%	*3.5%*
Earnings	7.0%	4.0%	*3.0%*
Dividends	7.0%	9.0%	*6.5%*
Book Value	5.5%	5.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	302.6	333.0	408.3	305.6	1349.5
2018	310.1	340.0	408.8	311.9	1370.8
2019	350.3	316.9	386.3	292.9	1346.4
2020	*335*	*335*	*400*	*305*	*1375*
2021	*340*	*350*	*415*	*320*	*1425*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.66	.99	1.80	.76	4.21
2018	.72	1.23	2.02	.52	4.49
2019	.84	1.05	1.78	.94	4.61
2020	*.85*	*1.05*	*1.90*	*.75*	*4.55*
2021	*.90*	*1.10*	*2.00*	*.75*	*4.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.51	.51	.51	.55	2.08
2017	.55	.55	.55	.59	2.24
2018	.59	.59	.59	.63	2.40
2019	.63	.63	.63	.67	2.56
2020	.67				

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 572,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.2 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 39%; commercial, 22%; industrial, 13%; irrigation, 10%; other, 16%. Generating sources: hydro, 45%; coal, 16%; gas, 11%; purchased, 28%. Fuel costs: 33% of revenues. '19 reported depreciation rate: 2.9%. Has 2,000 employees. Chairman: Richard J. Dahl. President & CEO: Darrel T. Anderson. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

We estimate that IDACORP's earnings will decline slightly in 2020. Fourth-quarter profits in 2019 were higher than usual because the company recorded $0.12 a share of income from a nonutility investment and amortization of an older tax credit. We do not assume that IDACORP will book similar income this year. Our 2020 earnings estimate is at the midpoint of management's targeted range of $4.45-$4.65 a share.

Idaho Power is better positioned than most utilities to deal with the problems associated with the coronavirus crisis. Like every electric company, commercial kilowatt-hour sales will decline as stores and other businesses are ordered to close temporarily. But much of the utility's industrial load should remain intact because it is related to agriculture and food processing. Moreover, there has been no cancelation or delay of several large projects announced by customers such as Amazon. Note, too, that Idaho Power may use up to $25 million of accumulated deferred investment tax credits every year if the utility's return on equity falls below 9.4%. Thus, the company can offset any decline in profitability that arises from a slump in commercial volume. Finally, a troubled economy is not an ideal situation for seeking a rate increase, and Idaho Power has no plans to file a rate application in Idaho or Oregon.

We look for the bottom line to advance in 2021. We expect solid growth in the utility's service territory to resume next year. Our earnings estimate of $4.75 a share would produce a 4% increase over our expected 2020 tally.

Finances are sound. The fixed-charge coverage and common-equity ratio are comfortably above average for this industry. IDACORP has no need to issue common equity to finance its capital spending. The company merits a Financial Strength rating of A.

The price of IDACORP stock has declined 12% this year. This is about as much as most utility issues have fallen. Still, the dividend yield is below the utility average. Total return potential is unspectacular for the 18-month span and the 3- to 5-year period. The recent quotation is within our 2023-2025 Target Price Range.

Paul E. Debbas, CFA *April 24, 2020*

(A) Diluted EPS. Excl. nonrecurring gain (loss): '05, (24¢); '06, 17¢. '17 & '19 earnings don't sum due to rounding. Next earnings report due late April. (B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '19: $26.31/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '11: 10% (imputed); earned on avg. com. eq., '19: 9.6%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	95

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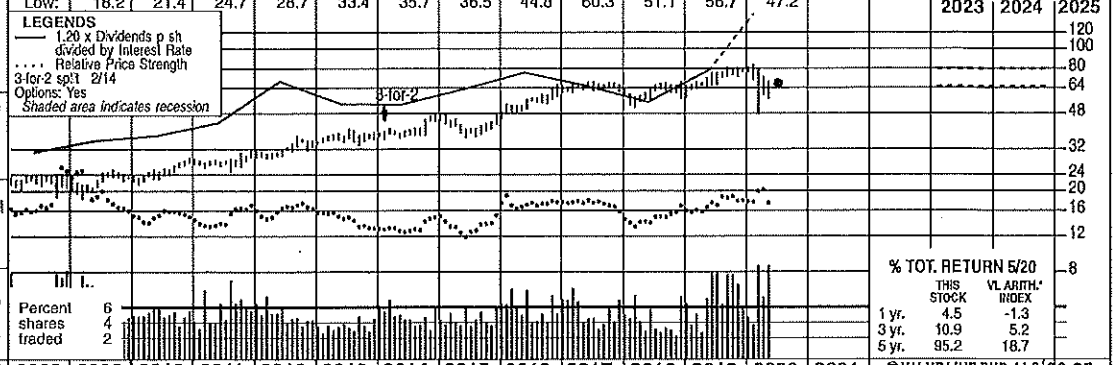
MGE ENERGY INC. NDQ-MGEE

RECENT PRICE 67.74 | P/E RATIO 26.1 (Trailing: 26.5 Median: 20.0) | RELATIVE P/E RATIO 1.32 | DIV'D YLD 2.2% | VALUE LINE

TIMELINESS 2 Lowered 5/22/20
SAFETY 1 New 1/3/03
TECHNICAL 3 Lowered 6/5/20
BETA .70 (1.00 = Market)

High:	25.5	29.1	31.9	37.4	40.5	48.0	48.0	66.9	68.7	68.9	80.8	83.3
Low:	18.2	21.4	24.7	28.7	33.4	35.7	36.5	44.8	60.3	51.1	56.7	47.2



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$52-$107	$80 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+20%)	6%
Low	65	(-5%)	2%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	74	75	61
to Sell	57	76	83
Hld's(000)	15877	15965	15334

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.5	-1.3
3 yr.	10.9	5.2
5 yr.	95.2	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
13.89	16.73	16.13	16.33	17.35	15.40	15.36	15.76	15.61	17.04	17.88	16.27	15.71	16.24	16.15	16.41	*14.40*	*15.20*	Revenues per sh	*17.00*
1.92	2.00	2.34	2.46	2.68	2.66	2.76	2.94	2.98	3.28	3.49	3.33	3.47	3.73	4.06	4.57	*4.65*	*4.90*	"Cash Flow" per sh	*5.50*
1.18	1.05	1.37	1.51	1.59	1.47	1.67	1.76	1.86	2.16	2.32	2.06	2.18	2.20	2.43	2.51	*2.60*	*2.70*	Earnings per sh A	*3.00*
.91	.92	.93	.94	.96	.97	.99	1.01	1.04	1.07	1.11	1.16	1.21	1.26	1.32	1.38	*1.45*	*1.52*	Div'd Decl'd per sh B ■ †	*1.80*
3.13	2.80	2.94	4.14	3.08	2.35	1.76	1.88	2.84	3.43	2.67	2.08	2.41	3.12	6.12	4.73	*6.25*	*6.20*	Cap'l Spending per sh	*4.50*
11.06	11.21	11.93	12.99	13.92	14.47	15.14	15.89	16.71	17.81	19.02	19.92	20.89	22.45	23.56	24.68	*27.10*	*28.30*	Book Value per sh C	*32.00*
30.59	30.68	31.46	32.93	34.36	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	*36.16*	*36.16*	Common Shs Outst'g D	*36.16*
18.0	22.4	15.9	15.0	14.2	15.1	15.0	15.8	17.2	17.0	17.2	20.3	24.9	29.4	25.1	28.4	*Bold figures are*		Avg Ann'l P/E Ratio	*24.0*
.95	1.19	.86	.80	.85	1.01	.95	.99	1.09	.96	.91	1.02	1.31	1.48	1.36	1.52	*Value Line*		Relative P/E Ratio	*1.50*
4.3%	3.9%	4.3%	4.1%	4.2%	4.4%	4.0%	3.6%	3.2%	2.9%	2.8%	2.8%	2.2%	2.0%	2.2%	1.9%	*estimates*		Avg Ann'l Div'd Yield	*2.5%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $545.3 mill. Due in 5 Yrs $72.5 mill.
LT Debt $522.6 mill. LT Interest $24.2 mill.
(LT interest earned: 5.8x)

Leases, Uncapitalized Annual rentals $1.9 mill.
Pension Assets-12/19 $386.0 mill. Obligation $410.6 mill.

Pfd Stock None

Common Stock 34,668,370 shs. as of 4/30/20

MARKET CAP: $2.3 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
532.6	546.4	541.3	590.9	619.9	564.0	544.7	563.1	559.8	568.9	*520*	*550*	Revenues ($mill)	*615*
57.7	60.9	64.4	74.9	80.3	71.3	75.6	76.1	84.2	68.9	*95.0*	*100*	Net Profit ($mill)	*110*
36.9%	37.1%	37.7%	37.5%	37.5%	36.7%	36.0%	36.4%	24.6%	18.5%	*16.0%*	*16.0%*	Income Tax Rate	*16.0%*
--	--	--	5.6%	5.7%	1.3%	2.1%	2.1%	5.2%	3.6%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
38.9%	39.6%	38.2%	39.3%	37.5%	36.2%	34.6%	33.8%	37.7%	38.0%	*37.0%*	*38.0%*	Long-Term Debt Ratio	*40.0%*
61.1%	60.4%	61.8%	60.7%	62.5%	63.8%	65.4%	66.2%	62.3%	62.0%	*63.0%*	*62.0%*	Common Equity Ratio	*60.0%*
859.4	911.9	937.9	1016.9	1054.7	1081.5	1106.9	1176.3	1310.0	1379.4	*1555*	*1650*	Total Capital ($mill)	*1925*
968.0	995.6	1073.5	1160.2	1208.1	1243.4	1282.1	1341.4	1509.4	1642.7	*1795*	*1940*	Net Plant ($mill)	*2150*
7.6%	7.8%	7.9%	8.3%	8.6%	7.5%	7.7%	7.3%	7.2%	7.1%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
11.0%	11.1%	11.1%	12.1%	12.2%	10.3%	10.4%	9.8%	10.3%	10.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
11.0%	11.1%	11.1%	12.1%	12.2%	10.3%	10.4%	9.8%	10.3%	10.2%	*9.5%*	*9.5%*	Return on Com Equity D	*9.5%*
4.4%	4.7%	4.9%	6.1%	6.4%	4.5%	4.7%	4.2%	4.7%	4.6%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
60%	57%	56%	50%	48%	56%	55%	57%	54%	55%	*55%*	*56%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.6	+1.6	-2.3
Avg. Indust. Use (MWH)	1966	1802	NA
Avg. Indust. Revs. per KWH (¢)	8.23	7.70	7.43
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	670	686	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	750	645	465

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	--	-.5%	.5%
"Cash Flow"	4.5%	5.0%	5.0%
Earnings	4.5%	2.5%	4.0%
Dividends	3.5%	4.0%	5.5%
Book Value	5.5%	5.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	156.8	126.5	139.5	140.3	563.1
2018	157.6	124.3	137.8	140.1	559.8
2019	167.6	122.2	138.2	140.9	568.9
2020	149.9	*110.1*	*130*	*130*	*520*
2021	*160*	*120*	*135*	*135*	*550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.56	.45	.77	.42	2.20
2018	.58	.53	.85	.47	2.43
2019	.69	.45	.88	.48	2.51
2020	.75	*.45*	*.90*	*.50*	*2.60*
2021	*.75*	*.48*	*.95*	*.52*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.295	.295	.3075	.3075	1.21
2017	.3075	.3075	.3225	.3225	1.26
2018	.3225	.3225	.3375	.3375	1.32
2019	.3375	.3375	.3525	.3525	1.38
2020	.3525				

BUSINESS: MGE Energy, Inc. is a holding company for Madison Gas and Electric Company (MGE), which provides electric service to 155,000 customers in Dane County and gas service to 163,000 customers in seven counties in Wisconsin. Electric revenue breakdown, '19: residential, 35%; commercial, 53%; industrial, 3%; other, 9%. Generating sources, '19: coal, 50%; gas, 14%; renewables, 14%; purchased power, 22%. Fuel costs: 34% of revenues. '19 reported depreciation rates: electric, 3.6%; gas, 2.1%; nonregulated, 2.3%. Has about 700 employees. Chairman, President & CEO: Jeffrey M. Keebler. Incorporated: Wisconsin. Address: 133 South Blair Street, P.O. Box 1231, Madison, Wisconsin 53701-1231. Telephone: 608-252-7000. Internet: www.mgeenergy.com.

MGE Energy issued some common stock in May. The company raised $80 million through the sale of 1.5 million shares. This was MGE Energy's first such issuance in more than 10 years. It raised cash to finance its capital budget, which is higher than usual this year and next.

MGE is better positioned than many utilities to deal with the effects of the weak economy. The utility's service area has a small industrial presence. Electric revenues from industrial customers were just 3% of the total in 2019. The utility reported that in April, retail kilowatt-hour sales declined 8.7%, but net profit was about equal to the year-earlier level. Utilities in Wisconsin are able to defer for future recovery costs associated with the coronavirus pandemic. Management is also cutting operating and maintenance expenses. However, MGE might delay its next rate case because this is not an opportune time for filing an application.

We have maintained our 2020 earnings estimate at $2.60 a share, but trimmed our 2021 estimate by a nickel. First-period profits were $0.05 a share above our expectation, but we didn't change our full-year estimate due to the increase in average shares outstanding. We did not anticipate a stock sale in our March report, and this is a factor in our revised estimate for 2021.

MGE is adding solar capacity. The utility will have 50-megawatt stakes in three projects, each of which will cost an estimated $65 million. One of these is expected to come on line in 2020, the other two next year. Some smaller projects are in the works, too.

We think the board of directors will raise the dividend in the third quarter. We estimate an increase of $0.07 a share (5.0%) in the annual disbursement. MGE Energy does not have a specified dividend policy, but notes that the payout ratio has been in a range of 50%-60% in recent years.

This timely stock has a high valuation for a utility, despite a price decline of 14% in 2020. The yield is a bit below the median of dividend-paying stocks under our coverage. The equity offers average total return potential for the 18-month period, but not for the pull to 2023-2025.

Paul E. Debbas, CFA *June 12, 2020*

(A) Diluted earnings. Excludes nonrecurring gain: '17, 62¢. '19 earnings don't sum due to rounding. Next earnings report due early May. (B) Dividends historically paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Includes regulatory assets. In '19: $167.0 mill., $4.82/sh. (D) In millions, adjusted for split. (E) Rate allowed on common equity in '19: 9.8%; earned on common equity, '19: 10.4%. Regulatory Climate: Above Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	95

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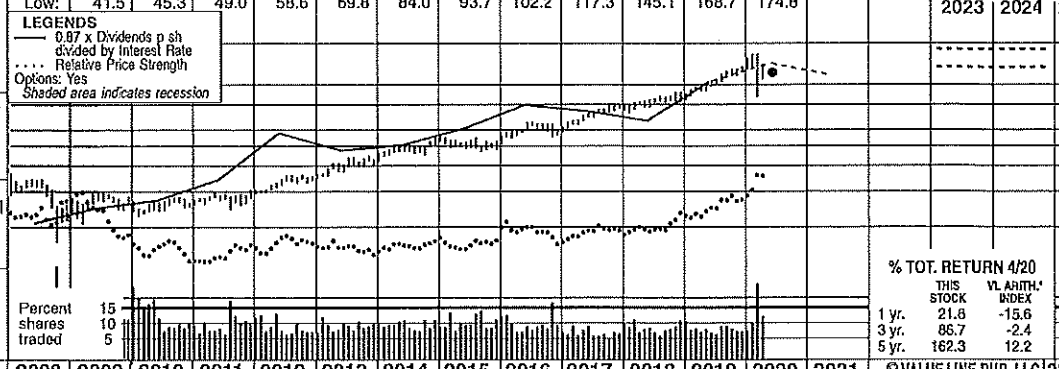
NEXTERA ENERGY NYSE-NEE

RECENT PRICE 230.09 | P/E RATIO 30.7 (Trailing: 31.9 Median: 18.0) | RELATIVE P/E RATIO 1.85 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 2 Lowered 4/24/20
SAFETY 1 Raised 2/16/18
TECHNICAL 1 Raised 5/15/20
BETA .85 (1.00 = Market)

High:	60.6	56.3	61.2	72.2	89.8	110.8	112.6	132.0	159.4	164.2	245.0	263.3
Low:	41.5	45.3	49.0	58.6	69.8	84.0	93.7	102.2	117.3	145.1	168.7	174.8

LEGENDS
— 0.87 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$213-$300	$257 (10%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	300	(+30%)	10%
Low	245	(+5%)	5%

Institutional Decisions

	2Q2018	3Q2019	4Q2019
to Buy	738	790	830
to Sell	624	616	666
Hld's(000)	370488	382169	384664

Percent shares traded 15 10 5

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.6	-15.6
3 yr.	86.7	-2.4
5 yr.	162.3	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
28.27	30.00	38.75	37.47	40.13	37.82	36.39	36.88	33.62	34.80	38.42	37.93	34.52	36.51	34.99	39.27	*42.35*	*44.90*	Revenues per sh	*52.00*
5.60	6.18	6.77	6.85	8.03	8.75	9.62	9.29	8.69	10.54	12.10	12.92	12.97	12.11	15.37	16.87	*17.25*	*20.05*	"Cash Flow" per sh	*23.75*
2.46	2.32	3.23	3.27	4.07	3.97	4.74	4.82	4.56	4.83	5.60	6.06	5.78	6.50	6.67	7.76	*7.50*	*9.80*	Earnings per sh A	*12.50*
1.30	1.42	1.50	1.64	1.78	1.89	2.00	2.20	2.40	2.64	2.90	3.08	3.48	3.93	4.44	5.00	*5.60*	*6.16*	Div'd Decl'd per sh B ■ †	*8.20*
3.75	4.09	9.22	12.32	12.80	14.52	13.89	15.93	22.31	15.36	15.84	18.17	20.59	22.80	27.21	25.15	*26.40*	*26.55*	Cap'l Spending per sh	*25.75*
20.25	21.52	24.49	26.35	28.57	31.35	34.36	35.92	37.90	41.47	44.96	48.97	52.01	59.69	71.43	75.67	*77.45*	*81.15*	Book Value per sh C	*98.75*
372.24	394.85	405.40	407.35	408.92	413.62	420.86	416.00	424.00	435.00	443.00	461.00	468.00	471.00	478.00	489.00	*490.00*	*490.00*	Common Shs Outst'g D	*495.00*
13.6	17.9	13.7	18.9	14.5	13.4	10.8	11.5	14.4	16.6	17.3	16.9	20.7	21.6	24.8	26.8	*Bold figures are*		Avg Ann'l P/E Ratio	*22.0*
.72	.95	.74	1.00	.87	.89	.69	.72	.92	.93	.91	.85	1.09	1.09	1.34	1.44	*Value Line*		Relative P/E Ratio	*1.20*
3.9%	3.4%	3.4%	2.7%	3.0%	3.5%	3.9%	4.0%	3.6%	3.3%	3.0%	3.0%	2.9%	2.8%	2.7%	2.4%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $47206 mill. Due in 5 Yrs $23217 mill.
LT Debt $41116 mill. LT Interest $1645 mill.

(LT interest earned: 3.4x)

Pension Assets-12/19 $4800 mill. Oblig $3363 mill.

Pfd Stock None

Common Stock 489,450,050 shs.

MARKET CAP: $113 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
15317	15341	14256	15136	17021	17486	16155	17195	16727	19204	*20750*	*22000*	Revenues ($mill)	*26200*
1957.0	2021.0	1911.0	2062.0	2465.0	2752.0	2693.0	3074.0	3200.0	3769.0	*3685*	*4820*	Net Profit ($mill)	*6315*
21.4%	22.4%	26.6%	26.9%	32.3%	30.8%	29.3%	24.4%	28.6%	11.7%	*9.0%*	*9.0%*	Income Tax Rate	*9.0%*
4.4%	4.4%	10.8%	7.0%	6.7%	6.9%	8.2%	6.7%	6.6%	3.9%	*4.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
55.5%	58.2%	59.1%	57.1%	55.0%	54.2%	53.3%	52.7%	44.0%	50.4%	*51.0%*	*51.0%*	Long-Term Debt Ratio	*49.5%*
44.5%	41.8%	40.9%	42.9%	45.0%	45.8%	46.7%	47.3%	56.0%	49.6%	*49.0%*	*49.0%*	Common Equity Ratio	*50.5%*
32474	35753	39245	42009	44283	49255	52159	59671	60926	74548	*77100*	*80800*	Total Capital ($mill)	*98400*
39075	42490	49413	52720	55705	61386	66912	72416	70334	82010	*90175*	*98200*	Net Plant ($mill)	*120800*
7.4%	7.0%	6.2%	6.2%	7.0%	6.8%	6.3%	6.3%	6.3%	6.0%	*5.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
13.5%	13.5%	11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	*9.5%*	*12.0%*	Return on Shr. Equity	*12.5%*
13.5%	13.5%	11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	*9.5%*	*12.0%*	Return on Com Equity E	*12.5%*
7.8%	7.4%	5.6%	5.2%	6.0%	6.1%	4.4%	4.4%	3.2%	3.7%	*2.5%*	*4.5%*	Retained to Com Eq	*4.5%*
42%	46%	53%	54%	51%	50%	60%	60%	66%	64%	*74%*	*63%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS F

	2017	2018	2019
% Change Retail Sales (KWH)	-.9	+1.4	+1.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	6.40	6.39
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	+1.8
Fixed Charge Cov. (%)	278	266	230

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-.5%	.5%	*6.0%*
"Cash Flow"	6.5%	7.0%	*8.0%*
Earnings	6.5%	7.0%	*10.0%*
Dividends	9.5%	11.0%	*10.5%*
Book Value	9.0%	10.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	3972	4404	4808	4011	17195
2018	3857	4063	4416	4391	16727
2019	4075	4970	5572	4587	19204
2020	4613	*5237*	*6000*	*4900*	*20750*
2021	*4900*	*5500*	*6400*	*5200*	*22000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.90	1.68	1.79	1.13	6.50
2018	2.06	1.64	2.10	.88	6.67
2019	1.41	2.56	1.81	1.99	7.76
2020	.86	*2.45*	*2.45*	*1.74*	*7.50*
2021	*2.60*	*2.70*	*2.65*	*1.85*	*9.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.87	.87	.87	.87	3.48
2017	.9825	.9825	.9825	.9825	3.93
2018	1.11	1.11	1.11	1.11	4.44
2019	1.25	1.25	1.25	1.25	5.00
2020	1.40				

BUSINESS: NextEra Energy, Inc. (formerly FPL Group, Inc.) is a holding company for Florida Power & Light Company (FPL) and Gulf Power, which provide electricity to 5.5 million customers in eastern, southern, & northwestern Florida. NextEra Energy Resources is a nonregulated power generator with nuclear, gas, & renewable ownership. Has 60.8% stake in NextEra Energy Partners. Rev. breakdown: residential, 55%; commercial, 35%; industrial & other, 10%. Generating sources: gas, 73%; nuclear, 22%; other, 3%; purch., 2%. Fuel costs: 23% of revs. '19 reported depr. rate (util.): 3.9%. Has 14,800 employees. Chairman, Pres. and CEO: James L. Robo. Inc.: FL. Address: 700 Universe Blvd., Juno Beach, FL 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

NextEra Energy is performing well, even though this wasn't reflected in first-quarter profits. The bottom line was depressed by mark-to-market charges for the company's energy-services business and unrealized losses on the decommissioning trusts for NextEra's nonregulated nuclear assets. (We *include* these because they are present every quarter.) This is why we look for full-year profits to decline. Florida Power & Light is seeing declines in kilowatt-hour sales stemming from the weak economy, but this isn't likely to hurt profits because a regulatory agreement allows the utility to amortize credits to income in order to offset any shortfall in earnings. In addition, except for a gas pipeline (see below), the company's construction projects are on track, including a $900 million, 1,200-megawatt gas-fired plant that is scheduled for completion in 2022. NextEra Energy Resources, the nonutility subsidiary, continues to add renewable-energy and battery-storage projects as planned, even with the coronavirus-related disruptions to the economy. Demand here remains strong, and the backlog is growing.

The addition of Gulf Power in early 2019 should boost NextEra's earnings this year and next. Management expects share-earnings contributions of $0.15 and $0.20 in 2020 and 2021, respectively. The company plans to merge Gulf Power with the much-larger FPL and intends to file a combined rate case in early 2021.

The board of directors increased the quarterly dividend by $0.15 a share (12%) in the first period. Beyond 2020, NextEra expects to hike the disbursement roughly 10% a year through 2022, at least.

A gas-pipeline project has had delays and cost overruns. This stems from litigation from environmental groups. The 31%-owned project is scheduled for completion in 2020 at a total cost of $5.4 billion, unchanged from the previous quarter.

This timely stock's price has declined just 5% in 2020. The weak economy has had little effect on the company's earning power. Unlike most utilities, the yield is below the median of all dividend-paying equities under our coverage. Also, total return potential is low for the 18-month and 3- to 5-year periods.

Paul E. Debbas, CFA *May 15, 2020*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '11, (24¢); '13, (80¢); '16, 47¢; '17, 91¢; '18, $7.19; gain on disc. ops.: '13, 44¢. '18 & '19 EPS don't sum due to rounding. Next earnings report due late July. (B) Div'ds historically paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '19: $18.26/sh. (D) In mill., adj. for stock split. (E) Rate allowed on com. eq. in '17 (FPL): 9.6%-11.6%; earned on avg. com. eq., '19: 10.6%. Regulatory Climate: Avg. (F) FPL only.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	95
Earnings Predictability	70

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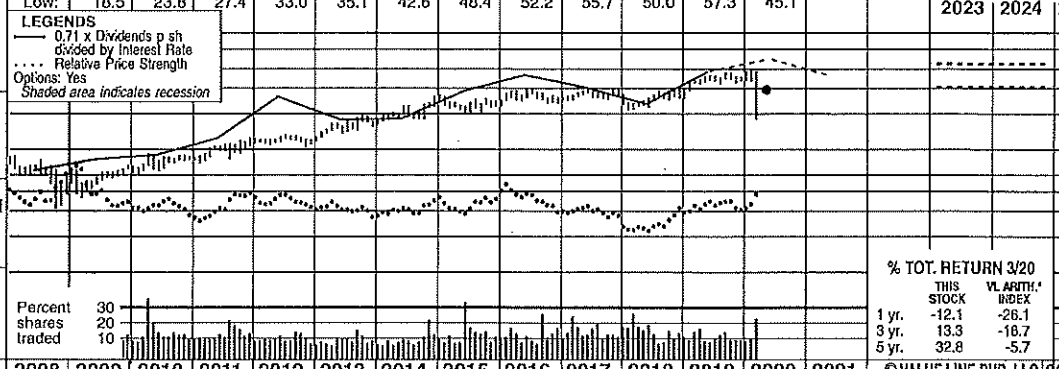
NORTHWESTERN NYSE-NWE

RECENT PRICE 63.30 | P/E RATIO 17.9 (Trailing: 17.9 Median: 17.0) | RELATIVE P/E RATIO 1.23 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 2 Raised 3/6/20
SAFETY 2 Raised 7/27/18
TECHNICAL 3 Raised 4/3/20
BETA .55 (1.00 = Market)

High:	26.8	30.6	36.6	38.0	47.2	58.7	59.7	63.8	64.5	65.7	76.7	80.5
Low:	18.5	23.8	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0	57.3	45.1

LEGENDS
— 0.71 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$59-$84	$72 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+35%)	11%
Low	65	(+5%)	5%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	131	113	127
to Sell	145	150	133
Hld's(000)	48906	49607	49394

Percent shares traded 30 20 10

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.1	-26.1
3 yr.	13.3	-16.7
5 yr.	32.8	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	24.93	*25.50*	*26.20*	Revenues per sh	*28.25*
3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	7.07	*7.15*	*7.40*	"Cash Flow" per sh	*8.50*
d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	3.53	*3.45*	*3.55*	Earnings per sh A	*4.00*
--	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	2.30	*2.40*	*2.50*	Div'd Decl'd per sh B ■ †	*2.80*
2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	5.64	6.26	*7.80*	*7.85*	Cap'l Spending per sh	*6.00*
19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	40.42	*41.55*	*42.70*	Book Value per sh C	*45.75*
35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	50.45	*51.00*	*51.50*	Common Shs Outst'g D	*53.00*
--	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	19.9	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
--	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.08	*Value Line*		Relative P/E Ratio	*1.05*
--	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $2253.2 mill. Due in 5 Yrs $448.1 mill.
LT Debt $2250.7 mill. LT Interest $83.7 mill.
Incl. $17.4 mill. capitalized leases.
(LT interest earned: 3.0x)

Pension Assets-12/19 $609.0 mill. Oblig $735.6 mill.

Pfd Stock None

Common Stock 50,478,630 shs. as of 2/7/20

MARKET CAP: $3.2 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
1110.7	1117.3	1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	*1300*	*1350*	Revenues ($mill)	*1500*
77.4	92.6	83.7	94.0	120.7	138.4	164.2	162.7	171.1	179.3	*175*	*185*	Net Profit ($mill)	*210*
25.0%	9.8%	9.6%	13.2%	--	13.7%	--	7.6%	7.6%	1.6%	*Nil*	*5.0%*	Income Tax Rate	*10.0%*
14.2%	3.3%	9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	3.4%	4.6%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
57.2%	52.2%	53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	*48.5%*	*51.0%*	Long-Term Debt Ratio	*49.5%*
42.8%	47.8%	46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	*51.5%*	*49.0%*	Common Equity Ratio	*50.5%*
1916.4	1797.1	2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	*4125*	*4505*	Total Capital ($mill)	*4825*
2118.0	2213.3	2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	*4910*	*5115*	Net Plant ($mill)	*5450*
5.9%	7.0%	5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	*5.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	*8.5%*	*8.5%*	Return on Shr. Equity	*8.5%*
9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	*8.5%*	*8.5%*	Return on Com Equity E	*8.5%*
3.5%	4.7%	3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	*2.5%*	*2.5%*	Retained to Com Eq	*2.5%*
63%	56%	65%	61%	54%	65%	58%	62%	64%	64%	*69%*	*70%*	All Div'ds to Net Prof	*70%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+3.8	+2.9	+4.6
Avg. Indust. Use (MWH)	30987	34573	37808
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2133	2173	2237
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.2	+1.2
Fixed Charge Cov. (%)	275	275	284

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-2.5%	-2.0%	*2.0%*
"Cash Flow"	5.0%	5.5%	*3.5%*
Earnings	7.0%	6.0%	*2.5%*
Dividends	5.5%	7.5%	*4.0%*
Book Value	6.0%	7.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	367.3	283.9	309.9	344.6	1305.7
2018	341.5	261.8	279.9	314.9	1198.1
2019	384.2	270.7	274.8	328.2	1257.9
2020	*365*	*285*	*310*	*340*	*1300*
2021	*380*	*295*	*320*	*355*	*1350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.17	.44	.75	.98	3.34
2018	1.18	.61	.56	1.06	3.40
2019	1.44	.49	.42	1.18	3.53
2020	*1.20*	*.55*	*.60*	*1.10*	*3.45*
2021	*1.25*	*.55*	*.60*	*1.15*	*3.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.50	.50	.50	.50	2.00
2017	.525	.525	.525	.525	2.10
2018	.55	.55	.55	.55	2.20
2019	.575	.575	.575	.575	2.30
2020	.60				

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 443,000 electric customers in Montana and South Dakota and 292,000 gas customers in Montana (85% of gross margin), South Dakota (14%), and Nebraska (1%). Electric revenue breakdown: residential, 39%; commercial, 47%; industrial, 4%; other, 10%. Generating sources: hydro, 34%; coal, 28%; wind, 5%; other, 3%; purchased, 30%. Fuel costs: 25% of revenues. '19 reported deprec. rate: 2.8%. Has 1,500 employees. Chairman: Stephen P. Adik. President & CEO: Robert C. Rowe. Inc.: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

We estimate that NorthWestern's earnings will decline moderately in 2020 and rebound in 2021. In 2019, the company benefited from favorable weather conditions in the first quarter. For the full year, weather boosted pretax income by $7.3 million (by management's estimate). We assume normal weather in 2020. Our estimate is at the low end of the company's guidance of $3.45-$3.60 a share, in view of the weak economy. We think normal utility growth will produce a profit increase in the low single-digit vicinity next year.

The company is adding generating capacity. Compared with other utilities in the Northwest, NorthWestern has more exposure to the vagaries of the purchased-power markets. In South Dakota, the company plans to build an $80 million gas-fired plant, which will provide 55-60 megawatts of capacity in late 2021. In Montana, NorthWestern would pay $0.50 to Puget Sound Energy for a 12.5% stake (92.5 mw) in Unit 4 of the Colstrip coal-fired station. The utility would sell 45 mw back to Puget Sound Energy and use the remainder to serve its customers. The deal requires the approval of the Montana Public Service Commission. A ruling is expected in the fourth quarter. Finally, NorthWestern has issued a request for proposals for up to 280 mw of capacity in Montana, which will be available in early 2023. The winning project(s) will be selected in the first quarter of 2021.

As usual, the board of directors raised the dividend in the first quarter. The increase was $0.10 a share (4.3%) annually, as we had expected. NorthWestern's target for the payout ratio is 60%-70%, and this figure is near the upper end of this range.

NorthWestern is asking the MPSC to approve a decoupling pilot program. This would last four years, beginning on July 1st, and would mean that electric revenues would no longer be linked with volume. The rest of the company's business would not be decoupled. Such programs reduce uncertainty for utilities.

The dividend yield of this timely stock is about average for a utility. The equity doesn't stand out for the 18-month or the 2023-2025 period. The price is down 12% in 2020, in line with most utilities.

Paul E. Debbas, CFA *April 24, 2020*

(A) Diluted EPS. Excl. gain (loss) on disc. ops.: '05, (6¢); '06, 1¢; nonrec. gains: '12, 39¢ net; '15, 27¢; '18, 52¢; '19, 45¢. '18 EPS don't sum due to rounding. Next earnings report due late April. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '19: $16.68/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '19 (elec.): 9.65%; in '17 (gas): 9.55%; in SD in '15: none spec.; in NE in '07: 10.4%; earned on avg. com. eq., '19: 9.0%. Reg. Climate: Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

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OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 32.14 | P/E RATIO 14.9 (Trailing: 14.3 Median: 17.0) | RELATIVE P/E RATIO 0.76 | DIV'D YLD 5.1% | VALUE LINE

TIMELINESS 3 Lowered 3/6/20
SAFETY 2 Lowered 12/18/15
TECHNICAL 3 Lowered 5/1/20
BETA 1.05 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$25-$62 $44 (35%)

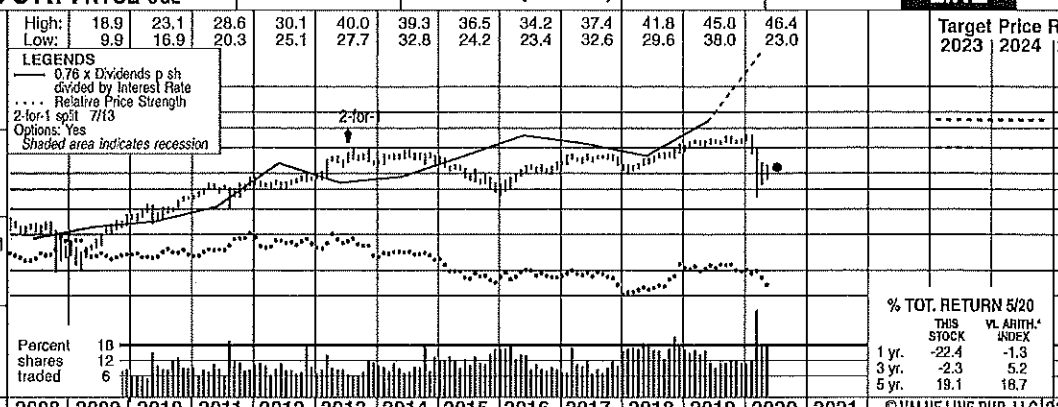
2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+70%)	18%
Low	40	(+25%)	10%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	177	205	176
to Sell	209	185	221
Hld's(000)	132772	133273	128589

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
High:	18.9	23.1	28.6	30.1	40.0	39.3	36.5	34.2	37.4	41.8	45.0	46.4
Low:	9.9	16.9	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6	38.0	23.0



Target Price Range 2023 | 2024 | 2025

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-22.4	-1.3
3 yr.	-2.3	5.2
5 yr.	19.1	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	*10.00*	*11.00*	Revenues per sh	*13.25*
1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	4.02	*4.05*	*4.30*	"Cash Flow" per sh	*5.25*
.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	2.24	*2.15*	*2.25*	Earnings per sh A	*2.50*
.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	*1.60*	*1.68*	Div'd Decl'd per sh B ■	*1.95*
1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	3.18	*2.90*	*3.65*	Cap'l Spending per sh	*3.75*
7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	20.69	*18.55*	*19.10*	Book Value per sh C	*21.00*
180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	200.10	*200.00*	*200.00*	Common Shs Outst'g D	*200.00*
14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	19.0	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.02	*Value Line*		Relative P/E Ratio	*1.10*
5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	4.0%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $3570.6 mill. Due in 5 Yrs $375.0 mill.
LT Debt $3195.6 mill. LT Interest $144.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $6.2 mill.

Pension Assets-12/19 $530.3 mill. Oblig $616.9 mill.

Pfd Stock None

Common Stock 200,169,431 shs.

MARKET CAP: $6.4 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
3716.9	3915.9	3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	*2000*	*2200*	Revenues ($mill)	*2650*
295.3	342.9	355.0	387.6	395.8	337.6	338.2	384.3	425.5	449.6	*425*	*450*	Net Profit ($mill)	*525*
34.9%	30.7%	26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
5.7%	9.0%	2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	*1.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.8%	51.6%	50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	*48.5%*	*48.0%*	Long-Term Debt Ratio	*48.5%*
49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	*51.5%*	*52.0%*	Common Equity Ratio	*51.5%*
4652.5	5300.4	5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	*7205*	*7320*	Total Capital ($mill)	*8150*
6464.4	7474.0	8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	*9235*	*9545*	Net Plant ($mill)	*10325*
7.8%	7.8%	7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	*11.5%*	*12.0%*	Return on Shr. Equity	*12.5%*
12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	*11.5%*	*12.0%*	Return on Com Equity E	*12.5%*
6.7%	7.7%	7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
48%	43%	44%	43%	47%	61%	67%	64%	64%	67%	*75%*	*75%*	All Div'ds to Net Prof	*74%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.2	+6.8	+1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.30	4.86	4.69
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6456	6863	6817
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+.9	+1.0
Fixed Charge Cov. (%)	315	292	335

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-5.0%	-5.5%	*2.5%*
"Cash Flow"	4.0%	1.0%	*6.0%*
Earnings	5.0%	2.0%	*3.0%*
Dividends	7.0%	10.0%	*6.0%*
Book Value	7.0%	5.5%	*1.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	456.0	586.4	716.8	501.9	2261.1
2018	492.7	567.0	698.8	511.8	2270.3
2019	490.0	513.7	755.4	472.5	2231.6
2020	431.3	*450*	*668.7*	*450*	*2000*
2021	*475*	*550*	*700*	*475*	*2200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.18	.52	.92	.30	1.92
2018	.27	.55	1.02	.27	2.12
2019	.24	.50	1.25	.26	2.24
2020	.23	*.58*	*1.11*	*.23*	*2.15*
2021	*.25*	*.60*	*1.15*	*.25*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.275	.275	.275	.3025	1.13
2017	.3025	.3025	.3025	.3325	1.24
2018	.3325	.3325	.3325	.365	1.36
2019	.365	.365	.365	.3875	1.48
2020	.3875	.3875			

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 858,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 25.5% of Enable Midstream Partners. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 10%; oilfield, 9%; other, 18%. Generating sources: gas, 35%; coal, 15%; wind, 5%; purchased, 45%. Fuel costs: 35% of revenues. '19 reported depreciation rate (utility): 2.7%. Has 2,400 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's stake in Enable Midstream Partners has been a drag on its stock price lately. The value of 25.5%-owned Enable, a midstream natural gas master limited partnership, has declined precipitously in 2020 due to depressed prices for gas and oil that have caused producers to reduce their activity. As a result, OGE took a nonrecurring $780 million pretax charge in the first quarter to write down its investment in Enable. So far this year, the price of OGE stock has declined 28%, making this issue one of the worst performers in the electric utility industry. Due to a decline in expected equity income from its stake in Enable, OGE lowered its 2020 share-net guidance from $2.19-$2.31 to $2.08-$2.18. We cut our 2020 and 2021 estimates by $0.10 each year, to $2.15 and $2.25, respectively, to reflect the likelihood of lower equity income from Enable.

Oklahoma Gas and Electric continues to perform well. Management has not changed its expectation for utility income this year, despite the weaker economy. At the start of April, OG&E received a $5.2 million increase in Arkansas under the state's formula rate plan. The utility is asking the Oklahoma commission to approve a plan to recover $810 million in modifications to the electric grid through a rider on customers' bills. A ruling is expected by yearend. There are few direct effects of the coronavirus problem. OG&E will be able to defer these costs for future recovery in Arkansas, and is asking for the same regulatory treatment in Oklahoma.

Finances are solid, even with the weak results at Enable. The aforementioned writedown was a noncash item. Although the distributions OGE gets from Enable have been halved, the company should still have ample cash to fund its capital bndget and pay dividends. We still expect a boost in the disbursement later this year. In April, the utility issued $300 million of 10-year notes at 3.25%, which will probably cover its financing needs through the end of 2021.

This stock has an attractive valuation. The dividend yield is well above the utility mean, and 18-month total return potential is strong. Total return prospects to 2023-2025 exceed those of most utility equities.

Paul E. Debbas, CFA *June 12, 2020*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '04, (3¢); '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.69); gains on discont. ops.: '05, 25¢; '06, 20¢. '18 & '19 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '19: $1.53/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '19: 11.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	40
Earnings Predictability	80

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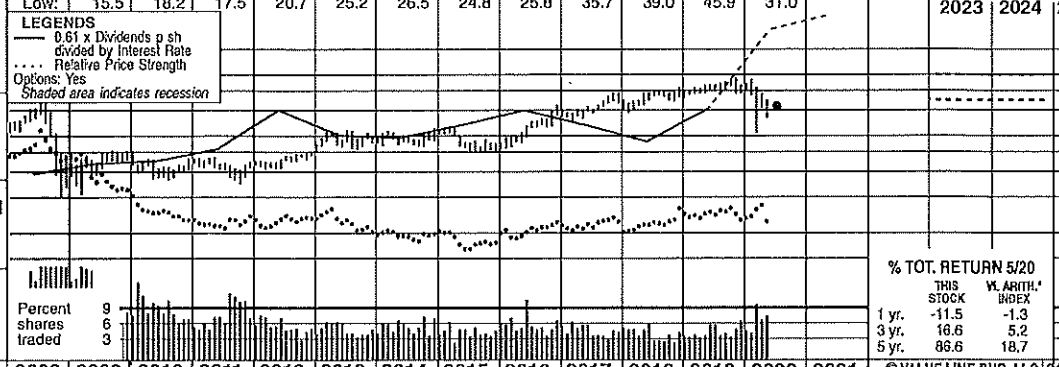
OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 42.00 | P/E RATIO 20.5 (Trailing: 19.8 Median: 22.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 3/1/19
SAFETY 2 Raised 6/17/16
TECHNICAL 3 Raised 5/8/20
BETA .85 (1.00 = Market)

High:	25.4	25.4	23.5	25.3	31.9	32.7	33.4	42.6	48.7	51.9	57.7	56.9
Low:	15.5	18.2	17.5	20.7	25.2	26.5	24.8	25.8	35.7	39.0	45.9	31.0

LEGENDS
— 0.61 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$37-$74	$56 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+45%)	12%
Low	45	(+5%)	6%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	88	85	78
to Sell	61	69	84
Hld's(000)	18133	18484	16228

Percent shares traded 9 6 3

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.5	-1.3
3 yr.	16.6	5.2
5 yr.	86.6	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	20.42	21.47	23.10	22.90	*20.70*	*22.60*	Revenues per sh	*26.50*
2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	3.70	3.96	4.11	*4.00*	*4.25*	"Cash Flow" per sh	*5.00*
1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	1.86	2.06	2.17	*2.05*	*2.20*	Earnings per sh A	*2.50*
1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	1.28	1.34	1.40	*1.48*	*1.56*	Div'd Decl'd per sh B ■	*1.60*
1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	3.36	2.66	5.16	*9.30*	*3.40*	Cap'l Spending per sh	*2.75*
14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	17.62	18.38	19.46	*20.60*	*21.20*	Book Value per sh C	*23.25*
28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	39.56	39.66	40.16	*41.50*	*41.60*	Common Shs Outst'g D	*41.50*
17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	18.2	20.2	22.1	22.2	23.5	*Bold figures are*		Avg Ann'l P/E Ratio	*20.5*
.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	.92	1.06	1.11	1.20	1.26	*Value Line*		Relative P/E Ratio	*1.15*
4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%	3.1%	2.9%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $744.5 mill. Due in 5 Yrs $190.3 mill.
LT Debt $724.3 mill. LT Interest $33.8 mill.
(LT interest earned: 4.1x)

Leases, Uncapitalized Annual rentals $22.3 mill.
Pension Assets-12/19 $329.8 mill. Oblig $384.8 mill.

Pfd Stock None

Common Stock 40,416,779 shs. as of 4/30/20

MARKET CAP: $1.7 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
1119.1	1077.9	859.2	893.3	799.3	779.8	803.5	849.4	916.4	919.5	*860*	*940*	Revenues ($mill)	*1115*
13.6	16.4	39.0	50.2	56.9	58.6	62.0	73.9	82.3	86.8	*85.0*	*90.0*	Net Profit ($mill)	*110*
--	14.5%	5.2%	21.3%	22.5%	27.0%	24.5%	25.5%	15.0%	16.7%	*18.0%*	*18.0%*	Income Tax Rate	*18.0%*
.6%	3.8%	1.7%	5.6%	3.9%	3.5%	2.2%	2.3%	4.1%	4.9%	*9.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
40.2%	44.6%	44.0%	42.1%	46.5%	42.4%	43.0%	41.3%	44.7%	46.9%	*42.0%*	*45.5%*	Long-Term Debt Ratio	*47.0%*
58.4%	54.0%	54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	*58.0%*	*54.5%*	Common Equity Ratio	*53.0%*
1083.3	1058.9	959.2	924.4	1071.3	1051.0	1175.4	1187.3	1318.9	1471.1	*1480*	*1615*	Total Capital ($mill)	*1850*
1108.7	1077.5	1049.5	1167.0	1268.5	1387.8	1477.2	1539.6	1581.1	1753.8	*2060*	*2115*	Net Plant ($mill)	*2275*
2.7%	3.2%	5.7%	6.8%	6.7%	6.8%	6.5%	7.3%	7.3%	7.0%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
2.1%	2.8%	7.3%	9.4%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	*10.0%*	*10.5%*	Return on Shr. Equity E	*11.0%*
2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	*10.0%*	*10.5%*	Return on Com Equity	*11.0%*
NMF	NMF	NMF	1.2%	2.2%	2.0%	2.1%	3.3%	4.0%	4.0%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
NMF	NMF	113%	87%	78%	79%	78%	69%	65%	64%	*72%*	*70%*	All Div'ds to Net Prof	*69%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+1.4	+3.4	-.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.26	5.97	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	917	912	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.2	+.1
Fixed Charge Cov. (%)	608	409	407

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-4.5%	-.5%	*3.0%*
"Cash Flow"	2.5%	6.0%	*4.0%*
Earnings	5.5%	9.0%	*3.5%*
Dividends	1.5%	2.5%	*5.0%*
Book Value	--	4.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	214.1	212.1	216.5	206.7	849.4
2018	241.2	226.3	227.7	221.2	916.4
2019	246.0	229.2	228.6	215.7	919.5
2020	234.7	*200*	*215*	*210.3*	*860*
2021	*250*	*235*	*235*	*220*	*940*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.49	.42	.45	.50	1.86
2018	.66	.47	.58	.35	2.06
2019	.66	.39	.62	.51	2.17
2020	.60	*.35*	*.60*	*.50*	*2.05*
2021	*.65*	*.40*	*.65*	*.50*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.3125	.3125	.3125	.3125	1.25
2017	.32	.32	.32	.32	1.28
2018	.335	.335	.335	.335	1.34
2019	.35	.35	.35	.35	1.40
2020	.37	.37			

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to 132,000 customers in Minnesota (52% of retail electric revenues), North Dakota (38%), and South Dakota (10%). Electric rev. breakdown: residential, 32%; commercial & farms, 36%; industrial, 30%; other, 2%. Generating sources: coal, 45%; wind & hydro, 8%; other, 1%; purchased, 46%. Fuel costs: 14% of revenues. Also has operations in manufacturing and plastics (38% of '18 income). '19 reported deprec. rate (utility): 2.8%. Has 2,300 employees. Chairman: Nathan I. Partain. President & CEO: Charles S. MacFarlane. Inc.: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Tel.: 866-410-8780. Internet: www.ottertail.com.

Otter Tail Corporation cut its earnings guidance for 2020. This is due to the effects of the weak economy, which is especially hurting the Manufacturing segment. Many customers of this division's businesses have had to close their facilities temporarily. Backlog is down, too. The division contributed $0.32 a share to the bottom line in 2019, and when management issued its 2020 earnings guidance of $2.22-$2.37 a share in February, it expected profits of $0.31-$0.35 a share from Manufacturing. In May, this was slashed to $0.14-$0.23 a share. As for Otter Tail Power, the economic troubles are hurting many of its industrial customers, and the suspension of shutoffs for nonpayment will cause bad-debt expense to rise. In response to these difficulties, the company is cutting costs. But there is only so much this can do, so Otter Tail reduced its 2020 earnings target to $2.00-$2.25 a share.

We lowered our 2020 and 2021 share-earnings estimates by $0.20 and $0.15, respectively. Demand from Otter Tail's customers isn't likely to bounce back to normal even as the economy continues to recover next year.

Otter Tail Power is building some significant capital projects. A $258 million, 150-megawatt wind project, the largest project in the company's history, is on budget but slightly behind schedule. An in-service date by yearend is still achievable, but there is an increased risk of supply-chain and labor-related delays due to coronavirus. This is significant because the company might lose production tax credits if the project is not completed by yearend. Otter Tail is also building a $158 million, 245-mw gas-fired facility. Completion is expected in late 2020 or early 2021. The company is financing these expenditures with a combination of long-term debt and common equity.

The reduction in earnings guidance didn't affect the stock price much. It came as no surprise to Wall Street that the economic troubles were hurting Otter Tail, especially its Manufacturing division. The price had already dropped significantly, and is down 18% in 2020. The dividend yield is about average for a utility. Total return potential is better for the 18-month span than for the 2023-2025 period.

Paul E. Debbas, CFA *June 12, 2020*

(A) Dil. EPS. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. '19 EPS don't sum due to rndg. Next egs. rept. due early Aug. (B) Div'ds histor. pd. in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $4.67/sh. (D) In mill. (E) Rate all'd on com. eq. In MN in '17: 9.41%; in ND in '18: 9.77%; in SD in '19: 8.75%; earn. avg. com. eq., '19: 11.6%. Reg. Clim.: MN, ND, Avg.; SD, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	85

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PORTLAND GENERAL NYSE-POR

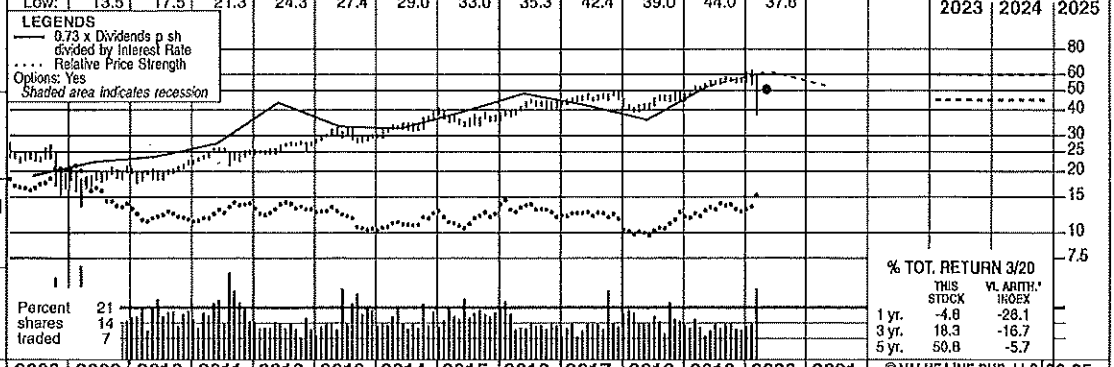
RECENT PRICE 50.84 | P/E RATIO 20.5 (Trailing: 21.3 Median: 17.0) | RELATIVE P/E RATIO 1.40 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 1 Raised 12/20/19
SAFETY 2 Raised 5/4/12
TECHNICAL 2 Raised 4/10/20
BETA .55 (1.00 = Market)

High:	21.4	22.7	26.0	28.1	33.3	40.3	41.0	45.2	50.1	50.4	58.4	63.1	
Low:	13.5	17.5	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0	44.0	37.6	

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$46-$68	$57 (10%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	7%
Low	45	(-10%)	1%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	142	151	160
to Sell	170	157	159
Hld's(000)	84749	84892	86645

Percent shares traded 21 14 7

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.8	-28.1
3 yr.	18.3	-16.7
5 yr.	50.8	-5.7

2004	2005F	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
--	23.14	24.32	27.87	27.69	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	23.75	*24.00*	*24.80*	Revenues per sh	*27.25*
--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	6.97	*7.25*	*7.65*	"Cash Flow" per sh	*9.00*
--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	2.39	*2.50*	*2.65*	Earnings per sh A	*3.00*
--	--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	1.52	*1.62*	*1.72*	Div'd Decl'd per sh B ■ †	*2.05*
--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	6.78	*10.15*	*6.80*	Cap'l Spending per sh	*5.75*
--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	28.99	*29.85*	*30.75*	Book Value per sh C	*33.75*
--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	89.39	*89.55*	*89.65*	Common Shs Outst'g D	*90.00*
--	--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	22.3	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
--	--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.21	*Value Line*		Relative P/E Ratio	*1.00*
--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $2748 mill. Due in 5 Yrs $316 mill.
LT Debt $2732 mill. LT Interest $137 mill.
Incl. $135 mill. capitalized leases.
(LT interest earned: 2.9x)
Leases, Uncapitalized Annual rentals $8 mill.
Pension Assets-12/19 $695 mill. Oblig $905 mill.

Pfd Stock None

Common Stock 89,463,547 shs. as of 2/28/20

MARKET CAP: $4.5 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
1783.0	1813.0	1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	*2150*	*2225*	Revenues ($mill)	*2450*
125.0	147.0	141.0	137.0	175.0	172.0	193.0	204.0	212.0	214.0	*225*	*240*	Net Profit ($mill)	*275*
30.5%	28.3%	31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	*11.0%*	*11.0%*	Income Tax Rate	*11.0%*
17.6%	5.4%	7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	*9.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
53.0%	49.6%	47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	*52.5%*	*53.5%*	Long-Term Debt Ratio	*52.5%*
47.0%	50.4%	52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	*47.5%*	*46.5%*	Common Equity Ratio	*47.5%*
3390.0	3298.0	3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	4684.0	5323.0	*5625*	*5915*	Total Capital ($mill)	*6375*
4133.0	4285.0	4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	*7645*	*7810*	Net Plant ($mill)	*7850*
5.4%	6.2%	5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	*8.5%*	*8.5%*	Return on Com Equity E	*9.0%*
3.0%	4.1%	3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
62%	54%	57%	61%	50%	56%	57%	58%	59%	63%	*64%*	*64%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+3.9	-2.5	+1.2
Avg. Indust. Use (MWH)	16041	16207	17827
Avg. Indust. Revs. per KWH (¢)	4.94	4.79	4.75
Capacity at Peak (Mw)	4743	4859	NA
Peak Load, Summer (Mw)	3976	3816	3765
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.1	+1.1
Fixed Charge Cov. (%)	298	266	265

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-1.5%	-1.0%	*3.0%*
"Cash Flow"	3.5%	4.0%	*5.5%*
Earnings	3.5%	4.0%	*4.0%*
Dividends	4.0%	5.5%	*6.0%*
Book Value	3.0%	3.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	530	449	515	515	2009
2018	493	449	525	524	1991
2019	573	460	542	548	2123
2020	*560*	*475*	*560*	*555*	*2150*
2021	*580*	*490*	*580*	*575*	*2225*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.82	.36	.44	.67	2.29
2018	.72	.51	.59	.55	2.37
2019	.82	.28	.61	.68	2.39
2020	*.85*	*.43*	*.52*	*.70*	*2.50*
2021	*.90*	*.45*	*.55*	*.75*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.30	.30	.32	.32	1.24
2017	.32	.32	.34	.34	1.32
2018	.34	.34	.3625	.3625	1.41
2019	.3625	.3625	.385	.385	1.50
2020	.385	.385			

BUSINESS: Portland General Electric Company (PGE) provides electricity to 895,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 30%; industrial, 9%; other, 14%. Generating sources: gas, 36%; coal, 19%; wind, 8%; hydro, 6%; purchased, 31%. Fuel costs: 29% of revenues. '19 reported depreciation rate: 3.6%. Has 2,900 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric's capital budget is higher than usual this year. The utility is spending $200 million to build an integrated operations center. This is expected to be completed in 2021. PGE is also a partner in a renewable-energy joint venture with NextEra Energy. PGE will pay $100 million for a one-third stake in a 300-megawatt windfarm, which is scheduled for completion by yearend. The utility chose not to file a general rate case this year, but will recover the cost of this project through a rider (surcharge) on customers' bills.

The company plans to add long-term debt this year. PGE's financing needs include the addition of up to $400 million of long-term debt (over and above what is needed for refinancing) this year. The company had no plans to issue equity, even before the market decline that began in late February.

We trimmed our 2020 share-earnings estimate by a nickel, to $2.50. This is the low end of PGE's guidance of $2.50-$2.65, which was issued in mid-February. We think a weakening economy will affect kilowatt-hour sales, so caution is in order. Although the utility operates under a regulatory mechanism that decouples revenues and volume, this only applies to kilowatt-hour sales declines resulting from energy efficiency, and not from economic weakness.

We estimate a 6% profit increase in 2021. PGE should benefit from rider recovery for the aforementioned windfarm. We figure kilowatt-hour sales will improve. The company's goal for earnings growth is 4%-6% annually.

The board of directors probably raised the dividend shortly after this report went to press. This is the usual timing of yearly increases. We look for a hike of $0.10 a share (6.5%) in the annual disbursement. PGE's goals for the dividend are yearly growth of 5%-7% and a payout ratio of 60%-70%.

This timely stock has a modest dividend yield, by utility standards. The stock's price decline of 9% this year is similar to that of other utility issues. Even among utilities, the equity doesn't stand out for total return potential for the 18-month or the 3- to 5-year period.

Paul E. Debbas, CFA *April 24, 2020*

(A) Diluted EPS. Excl. nonrecurring losses: '13, 42¢; '17, 19¢. Next earnings report due late July. (B) Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '19: $483 mill., $5.40/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '19: 9.5%; earned on avg. com. eq., '19: 8.4%. Regulatory Climate: Average. (F) '05 per-share data are pro forma, based on shs. outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	85

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PG&E CORP. NYSE-PCG

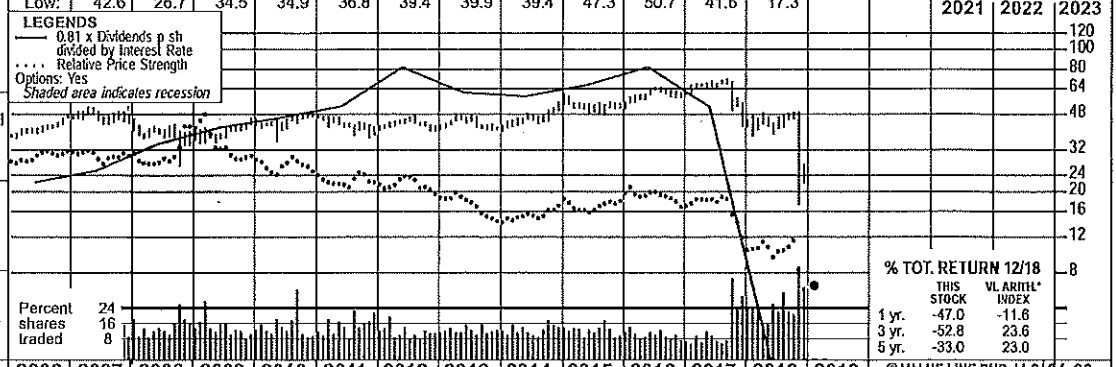
RECENT PRICE 6.91 | P/E RATIO NMF (Trailing: 12.6 Median: 18.0) | RELATIVE P/E RATIO NMF | DIV'D YLD Nil | VALUE LINE

TIMELINESS — Suspended 1/25/19
SAFETY 5 Lowered 1/18/19
TECHNICAL — Suspended 1/25/19
BETA .65 (1.00 = Market)

High:	52.2	45.7	45.8	48.6	48.0	47.0	48.5	55.2	60.2	65.4	71.6	49.4
Low:	42.6	26.7	34.5	34.9	36.8	39.4	39.9	39.4	47.3	50.7	41.6	17.3

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.81 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High		SEE	
Low		TEXT	

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	8	0	10	0	0	0	1	0	0
to Sell	3	0	0	1	0	0	0	0	0

Institutional Decisions

	1Q2018	2Q2018	3Q2018
to Buy	306	286	286
to Sell	302	297	291
Hld's(000)	418610	422304	430496

Percent shares traded 24 16 8

% TOT. RETURN 12/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-47.0	-11.6
3 yr.	-52.8	23.6
5 yr.	-33.0	23.0

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	36.28	34.92	34.16	35.91	34.21	34.85	33.29	*32.30*		Revenues per sh	
1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	8.08	7.32	6.33	8.13	7.29	8.23	9.03	*6.20*		"Cash Flow" per sh	
d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	2.78	2.07	1.63	3.06	2.00	2.83	3.50	*.45*		Earnings per sh A	
--	--	--	1.23	1.32	1.44	1.56	1.68	1.82	1.82	1.82	1.82	1.82	1.82	1.93	1.55	--	SEE	Div'd Decl'd per sh B	SEE
7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	9.79	10.74	11.40	10.16	10.51	11.26	10.96	*12.10*	TEXT	Cap'l Spending per sh	TEXT
9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	29.35	30.35	31.41	33.09	33.69	35.39	37.34	*37.80*		Book Value per sh C	
381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	412.26	430.72	456.67	475.91	492.03	506.89	514.76	*520.00*		Common Shs Outst'g D	
--	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	15.5	20.7	23.7	15.0	26.4	21.1	18.3	*NMF*		Avg Ann'l P/E Ratio	
--	.54	.73	.82	.80	.89	.73	.87	1.01	.97	1.32	1.33	.79	1.33	1.11	.92	*NMF*		Relative P/E Ratio	
--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%	4.2%	4.2%	4.2%	4.0%	3.4%	3.2%	2.4%	--		Avg Ann'l Div'd Yield	
						14628	13399	13841	14956	15040	15598	17090	16833	17666	17135	*16800*		Revenues ($mill)	
						1198.0	1168.0	1113.0	1132.0	893.0	828.0	1450.0	988.0	1431.0	1807.0	*240*		Net Profit ($mill)	
						26.2%	31.1%	33.0%	30.3%	23.9%	24.5%	19.2%	--	3.7%	16.8%	*NMF*		Income Tax Rate	
						9.5%	11.9%	14.4%	11.2%	17.5%	17.9%	10.0%	15.7%	11.4%	7.0%	*62.0%*		AFUDC % to Net Profit	
						52.2%	51.4%	49.6%	48.8%	48.7%	46.6%	48.5%	48.8%	47.1%	47.7%	*47.5%*		Long-Term Debt Ratio	
						46.5%	47.4%	49.3%	50.2%	50.4%	52.5%	50.7%	50.4%	52.1%	51.6%	*51.5%*	SEE	Common Equity Ratio	SEE
						20163	21793	22863	24119	25956	27311	31050	32858	34412	37225	*38050*	TEXT	Total Capital ($mill)	TEXT
						26261	28892	31449	33655	37523	41252	43941	46723	50581	53789	*57125*		Net Plant ($mill)	
						7.8%	6.7%	6.2%	5.9%	4.7%	4.2%	5.8%	4.1%	5.2%	5.9%	*1.5%*		Return on Total Cap'l	
						12.4%	11.0%	9.6%	9.2%	6.7%	5.7%	9.1%	5.9%	7.9%	9.3%	*1.0%*		Return on Shr. Equity	
						12.6%	11.2%	9.7%	9.2%	6.7%	5.7%	9.1%	5.9%	7.9%	9.3%	*1.0%*		Return on Com Equity E	
						6.8%	5.5%	3.9%	3.4%	1.0%	.2%	3.9%	.7%	2.8%	4.0%	*1.0%*		Retained to Com Eq	
						47%	52%	61%	63%	85%	96%	58%	88%	65%	57%	--		All Div'ds to Net Prof	

CAPITAL STRUCTURE as of 9/30/18
Total Debt $19350 mill. Due in 5 Yrs $4158 mill.
LT Debt $18407 mill. LT Interest $845 mill.
(Interest not earned.)
Leases, Uncapitalized Annual rentals $44 mill.
Pension Assets-12/17 $16652 mill.
Oblig $18757 mill.
Pfd Stock $252 mill. Pfd Div'd $14 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par. Div'ds suspended as of 12/17.
Common Stock 518,674,276 shs. as of 10/25/18
MARKET CAP: $3.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.5	-3.3	-1.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	9.73	9.90	10.55
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.7	+.7	+.7
Fixed Charge Cov. (%)	189	242	310

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	-.5%	
"Cash Flow"	.5%	1.0%	SEE
Earnings	.5%	1.5%	TEXT
Dividends	3.0%	-.5%	
Book Value	5.0%	4.0%	

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	3899	4217	4550	4167	16833
2016	3974	4169	4810	4713	17666
2017	4268	4250	4517	4100	17135
2018	4056	4234	4381	*4129*	*16800*
2019		SEE	TEXT		

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.27	.83	.63	.27	2.00
2016	.22	.46	.77	1.36	2.83
2017	1.13	.79	1.07	.51	3.50
2018	.86	d1.91	1.09	*.41*	*.45*
2019		SEE	TEXT		

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.455	.455	.455	.455	1.82
2016	.455	.455	.49	.49	1.89
2017	.49	.49	.53	.53	2.04
2018	--	--	--	--	--
2019					

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California (population 16 million). Has 5.4 million electric and 4.5 million gas customers. Electric revenue breakdown: residential, 41%; commercial, 39%; industrial, 12%; agricultural, 8%; other, less than 1%. Generating sources: nuclear, 27%; hydro, 17%; gas, 9%; purchased, 47%. Fuel costs: 30% of revenues. '17 reported depreciation rate (utility): 3.8%. Has 23,000 employees. Chairman: Richard C. Kelly. Interim President & CEO: John Simon. Incorporated: California. Address: 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. Telephone: 415-973-1000. Internet: www.pgecorp.com.

PG&E Corporation and its utility subsidiary, Pacific Gas and Electric, plan to file for protection under Chapter 11 of the U.S. Bankruptcy Code. This is expected to occur on or about January 29th, following a 15-day notice period mandated by California law. This stems from as-yet undetermined (but probably above $30 billion) liabilities associated with wildfires that occurred in 2017 and 2018 in the utility's service area in northern California. This is far greater than the sum of PG&E's insurance coverage and cash on hand. A state agency has blamed the utility for some of the 2017 wildfires; reports on other fires are pending. What makes this situation especially troublesome is California's inverse condemnation law. As the company stated in an 8-K filing with the SEC, "If the Utility's facilities . . . are determined to be the substantial cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, business interruption, interest and attorneys' fees without having been found negligent." The company's chief executive officer, Geisha Williams, stepped down, and the board appointed an interim CEO.

The price of PG&E's stock has fallen substantially. Following the latest wildfires, in November, investors became even more concerned about the prospective size of the liabilities. The price plummeted 47% in 2018, and is down more than 70% so far in 2019.

The utility filed a general rate case. PG&E requested a rate increase of more than $1 billion for 2020. Among other things, this reflects the soaring cost of wildfire insurance and measures PG&E is taking to address the wildfire problems. New tariffs will take effect at the start of 2020 (retroactively if an order has not been issued by then).

We advise investors to avoid this stock. Whether there will be anything left for common stockholders once the reorganization is completed is questionable. The equity's Timeliness rank is suspended due to the Chapter 11 filing.

This is our final report on PG&E stock. Due to the prospective bankruptcy filing, making estimates and projections beyond 2018 is virtually impossible.

Paul E. Debbas, CFA *January 25, 2019*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '04, $6.95; '09, 18¢; '11, (68¢); '12, (15¢); '15, (21¢); '16, (5¢); '17, (29¢); gain from discontinued operations: '08, 41¢. '16 EPS don't sum due to change in shares outstanding. Next earnings report due mid-Feb. (B) Dividends suspended 12/17. (C) Incl. intangibles. In '17: $7.37/sh. (D) In mill. (E) Rate base: net original cost. Rate allowed on com. eq. in '15: 10.4%; earned on avg. com. eq., '17: 9.6%. Regulatory Climate: Average.

Company's Financial Strength	C
Stock's Price Stability	80
Price Growth Persistence	25
Earnings Predictability	35

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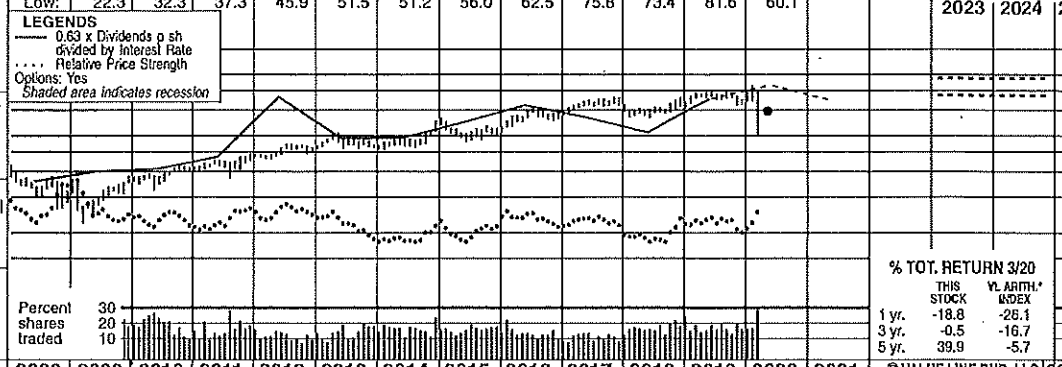
PINNACLE WEST NYSE-PNW

RECENT PRICE 79.61 | P/E RATIO 15.9 (Trailing: 16.7 Median: 16.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Lowered 8/30/19
SAFETY 1 Raised 5/3/13
TECHNICAL 3 Raised 3/13/20
BETA .45 (1.00 = Market)

High:	38.0	42.7	48.9	54.7	61.9	71.1	73.3	82.8	92.5	92.6	99.8	105.5
Low:	22.3	32.3	37.3	45.9	51.5	51.2	56.0	62.5	75.8	73.4	81.6	60.1

LEGENDS
—— 0.63 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$61-$130	$96 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+45%)	13%
Low	95	(+20%)	8%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	266	245	221
to Sell	188	225	251
Hld's(000)	100901	98235	98387

Percent shares traded 30 20 10

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-18.8	-26.1
3 yr.	-0.5	-16.7
5 yr.	39.9	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	32.93	30.87	*31.05*	*32.75*	Revenues per sh	*35.50*
6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.79	11.41	11.13	*11.50*	*12.35*	"Cash Flow" per sh	*14.50*
2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	4.54	4.77	*4.75*	*5.15*	Earnings per sh A	*6.00*
1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	2.87	3.04	*3.22*	*3.41*	Div'd Decl'd per sh B ■	*4.00*
5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	10.73	10.76	*12.25*	*15.20*	Cap'l Spending per sh	*11.75*
32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	46.59	48.30	*49.75*	*51.35*	Book Value per sh C	*58.00*
91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	112.10	112.44	*112.70*	*113.00*	Common Shs Outst'g D	*118.00*
15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	17.8	19.4	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	.97	.96	1.05	*Value Line*		Relative P/E Ratio	*.95*
4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%	3.5%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $5747.2 mill. Due in 5 Yrs $1279.8 mill.
LT Debt $4832.6 mill. LT Interest $198.7 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $14.7 mill.
Pension Assets-12/19 $3318.4 mill. Oblig $3613.1 mill.

Pfd Stock None

Common Stock 112,439,441 shs. as of 2/14/20
MARKET CAP: $9.0 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
3263.6	3241.4	3301.8	3454.6	3491.6	3495.4	3498.7	3565.3	3691.2	3471.2	*3500*	*3700*	Revenues ($mill)	*4200*
330.4	328.2	387.4	406.1	397.6	437.3	442.0	497.8	511.0	538.3	*535*	*585*	Net Profit ($mill)	*710*
31.9%	34.0%	36.2%	34.4%	34.2%	34.3%	33.9%	32.5%	20.2%	20.2%	*14.0%*	*14.0%*	Income Tax Rate	*14.0%*
11.7%	12.8%	9.7%	10.0%	11.6%	11.8%	14.1%	13.9%	15.2%	9.3%	*7.0%*	*12.0%*	AFUDC % to Net Profit	*7.0%*
45.3%	44.1%	44.6%	40.0%	41.0%	43.0%	45.6%	48.9%	47.0%	47.1%	*53.0%*	*53.0%*	Long-Term Debt Ratio	*51.5%*
54.7%	55.9%	55.4%	60.0%	59.0%	57.0%	54.4%	51.1%	53.0%	52.9%	*47.0%*	*47.0%*	Common Equity Ratio	*48.5%*
6729.1	6840.9	7171.9	6990.9	7398.7	8046.3	8825.4	9796.4	9861.1	10263	*11900*	*12325*	Total Capital ($mill)	*14125*
9578.8	9962.3	10396	10889	11194	11809	12714	13445	14030	14523	*15150*	*16050*	Net Plant ($mill)	*17800*
6.5%	6.4%	6.8%	7.1%	6.4%	6.4%	6.0%	6.1%	6.2%	6.3%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	*9.5%*	*10.0%*	Return on Shr. Equity	*10.5%*
9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	*9.5%*	*10.0%*	Return on Com Equity E	*10.5%*
3.1%	2.8%	4.1%	4.1%	3.5%	3.9%	3.5%	4.2%	3.9%	3.8%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
66%	68%	58%	58%	62%	59%	62%	58%	60%	61%	*67%*	*66%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	--	-.3	-.3
Avg. Indust. Use (MWH)	620	662	714
Avg. Indust. Revs. per KWH (¢)	8.34	8.40	7.88
Capacity at Peak (Mw)	8438	8643	8241
Peak Load, Summer (Mw)	7363	7320	7115
Annual Load Factor (%)	46.3	47.0	47.1
% Change Customers (yr-end)	+1.8	+2.0	+2.0
Fixed Charge Cov. (%)	425	318	286

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-.5%	.5%	*2.0%*
"Cash Flow"	2.5%	6.0%	*5.0%*
Earnings	6.5%	5.0%	*4.5%*
Dividends	3.0%	3.5%	*5.5%*
Book Value	3.0%	4.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	677.7	944.6	1183.3	759.7	3565.3
2018	692.7	974.1	1268.0	756.4	3691.2
2019	740.5	869.5	1190.8	670.4	3471.2
2020	*700*	*900*	*1200*	*700*	*3500*
2021	*750*	*950*	*1250*	*750*	*3700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.21	1.49	2.46	.27	4.43
2018	.03	1.48	2.80	.23	4.54
2019	.16	1.28	2.77	.57	4.77
2020	*.05*	*1.45*	*2.95*	*.30*	*4.75*
2021	*.10*	*1.55*	*3.15*	*.35*	*5.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.625	.625	.625	.655	2.53
2017	.655	.655	.655	.695	2.66
2018	.695	.695	.695	.7375	2.82
2019	.7375	.7375	.7375	.7825	3.00
2020	.7825				

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.3 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 51%; commercial, 38%; industrial, 5%; other, 6%. Generating sources: nuclear, 28%; gas & other, 28%; coal, 24%; purchased, 20%. Fuel costs: 30% of revenues. '19 reported deprec. rate: 2.8%. Has 6,200 employees. Chairman, President & CEO: Jeffrey B. Guldner. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary has a rate case pending. Arizona Public Service filed for an increase of $184 million (5.6%), based on a 10.5% return on equity and a 54.7% common-equity ratio. Included in the application is a request to place a $390 million upgrade to a coal-fired station in the rate base. The utility also wants the Arizona Corporation Commission (ACC) to grant it some regulatory mechanisms, such as one that would defer for future recovery any increases in property taxes. The initial schedule had indicated that an order might come as early as December 1st, but it now appears as if this won't occur until the first or second quarter of 2021. Even before the coronavirus-related disruptions to normal operations emerged, the ACC's staff was seeking a delay in the schedule. Unless the delay lasts well into the June quarter next year, this won't have a large effect on the company's earnings because the first and fourth quarters are seasonally weak because there is less use of air conditioning.

We have trimmed our 2020 earnings estimate by $0.10 a share, to $4.75. This is the low end of Pinnacle West's targeted range of $4.75-$4.95. Management reaffirmed this when the company reported fourth-quarter results in late February, but this was before the state of the economy began to decline. We think a decline in commercial sales will hurt the utility, even if residential sales improve partially because people are staying home. Certain costs, such as bad-debt expense, are also headed higher, so attaining the company's operating and maintenance expense target might well be challenging.

We estimate a solid profit increase in 2021. We figure the economy will be in better condition. The utility should also benefit from rate relief. However, if an order on the pending rate case doesn't come until well into the second quarter of 2021, our estimate might well prove to be too high.

This stock is of interest for conservative, income-oriented investors. The equity is ranked 1 (Highest) for Safety. The dividend yield is a cut above the utility mean. Total return potential for the 18-month and 3- to 5-year periods is also better than those of most utility issues.

Paul E. Debbas, CFA *April 24, 2020*

(A) Diluted EPS. Excl. nonrec. gain (loss): '09, ($1.45); '17, 8¢; gains (losses) from discont. ops.: '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '19 EPD don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '19: $14.00/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '17: 10.0%; earned on avg. com. eq., '19: 10.1%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	95

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PNM RESOURCES NYSE-PNM

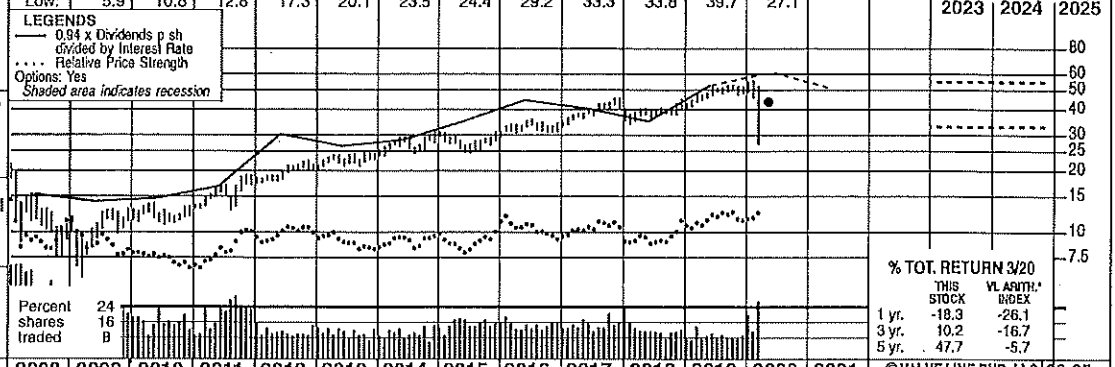
RECENT PRICE 43.79 | P/E RATIO 23.0 (Trailing: 19.2 Median: 18.0) | RELATIVE P/E RATIO 1.58 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 4/24/20
SAFETY 3 Lowered 5/9/08
TECHNICAL 3 Lowered 4/17/20
BETA .50 (1.00 = Market)

High:	13.1	14.0	19.2	22.5	24.5	31.6	31.2	36.2	46.0	45.3	53.0	56.1
Low:	5.9	10.8	12.8	17.3	20.1	23.5	24.4	29.2	33.3	33.8	39.7	27.1

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.94 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$34-$78	$56 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	9%
Low	33	(-25%)	-3%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	105	116	135
to Sell	124	130	116
Hld's(000)	72648	72521	73262

Percent shares traded 24 16 8

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-18.3	-26.1
3 yr.	10.2	-16.7
5 yr.	47.7	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14	16.04	16.30	*16.30*	*16.90*	Revenues per sh	*18.00*
3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	5.13	6.07	*5.40*	*6.20*	"Cash Flow" per sh	*7.25*
1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	1.66	2.28	*1.80*	*2.25*	Earnings per sh A	*2.75*
.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	1.09	1.18	*1.24*	*1.30*	Div'd Decl'd per sh B ■ †	*1.50*
2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28	6.29	7.74	*9.80*	*11.55*	Cap'l Spending per sh	*6.00*
18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	21.28	21.20	21.08	*23.40*	*24.35*	Book Value per sh C	*29.25*
60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	*85.83*	*85.83*	Common Shs Outst'g D	*92.00*
15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	23.4	21.1	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.79	.93	.84	1.89	NMF	1.21	.69	.91	.95	.90	.98	.94	1.18	1.03	1.26	1.14	*Value Line*		Relative P/E Ratio	*.90*
2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.6%	3.0%	2.8%	2.5%	2.8%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $3192.8 mill. Due in 5 Yrs $1663.4 mill.
LT Debt $2517.5 mill. LT Interest $112.2 mill.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $30.7 mill.
Pension Assets-12/18 $545.0 mill.
Oblig $624.8 mill.
Pfd Stock $11.5 mill. Pfd Div'd $.5 mill.
115,293 shs. 4.56%, $100 par without mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 2/21/20
MARKET CAP: $3.5 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
1673.5	1700.6	1342.4	1387.9	1435.9	1439.1	1363.0	1445.0	1436.6	1457.6	*1400*	*1450*	Revenues ($mill)	*1650*
80.5	97.1	106.1	114.0	116.8	118.8	117.4	154.4	133.4	182.8	*160*	*210*	Net Profit ($mill)	*265*
32.6%	38.8%	31.4%	31.6%	34.8%	36.9%	32.4%	33.0%	13.8%	9.4%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
7.1%	8.7%	7.1%	1.3%	10.7%	17.0%	11.0%	11.9%	14.5%	9.2%	*13.0%*	*12.0%*	AFUDC % to Net Profit	*7.0%*
50.4%	51.5%	50.9%	50.0%	47.8%	54.1%	55.7%	56.1%	61.1%	59.8%	*48.5%*	*54.0%*	Long-Term Debt Ratio	*50.5%*
49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	*51.0%*	*46.0%*	Common Equity Ratio	*49.0%*
3100.3	3245.6	3277.9	3344.0	3437.1	3633.3	3806.8	3887.5	4370.0	4207.7	*3940*	*4565*	Total Capital ($mill)	*5450*
3444.4	3627.1	3746.5	3933.9	4270.0	4535.4	4904.7	4980.2	5234.6	5466.0	*5985*	*6635*	Net Plant ($mill)	*7475*
4.2%	4.5%	5.1%	5.2%	5.1%	4.8%	4.7%	5.3%	4.3%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.0%	7.8%	10.8%	*7.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	7.9%	10.9%	*7.0%*	*9.0%*	Return on Com Equity E	*9.5%*
2.2%	3.3%	3.8%	3.8%	3.2%	3.3%	2.6%	4.5%	2.9%	5.4%	*2.0%*	*4.0%*	Retained to Com Eq	*4.5%*
57%	47%	43%	45%	51%	54%	61%	51%	64%	51%	*72%*	*58%*	All Div'ds to Net Prof	*54%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+.3	+7.3	+5.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2580	2661	2761
Peak Load, Summer (Mw)	1843	1885	1937
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+1.1	NA
Fixed Charge Cov. (%)	243	218	228

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-2.0%	1.0%	*Nil*
"Cash Flow"	9.5%	8.5%	*4.5%*
Earnings	15.0%	7.0%	*6.0%*
Dividends	5.0%	10.0%	*5.5%*
Book Value	.5%	--	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	330.2	362.3	419.9	332.6	1445.0
2018	317.9	352.3	422.7	343.7	1436.6
2019	349.7	330.2	433.6	344.1	1457.6
2020	333.6	*320*	*415*	*331.4*	*1400*
2021	*345*	*330*	*430*	*345*	*1450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.29	.47	.92	.25	1.92
2018	.19	.48	1.09	d.10	1.66
2019	.23	.36	1.29	.40	2.28
2020	d.19	*.45*	*1.24*	*.30*	*1.80*
2021	*.18*	*.47*	*1.30*	*.30*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.22	.22	.22	.22	.88
2017	.2425	.2425	.2425	.2425	.97
2018	.265	.265	.265	.265	1.06
2019	.29	.29	.29	.29	1.16
2020	.3075				

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 532,000 customers in north central New Mexico, incl. Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 257,000 customers in Texas. Electric revenue breakdown: residential, 40%; commercial, 35%; industrial, 6%; other, 19%. Generating sources not available. Fuel costs: 28% of revenues. '19 reported deprec. rates: 2.5%-7.9%. Has 1,700 employees. Chairman, President & CEO: Patricia K. Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources' utility subsidiary in New Mexico received a key regulatory decision. P.S. of New Mexico proposed closing the San Juan coal-fired plant in mid-2022. The utility intends to issue securitized bonds to recover the undepreciated cost of the facility and other related expenses, and replace the plant's capacity with a combination of purchased-power contracts and company-owned assets. The New Mexico commission approved the closing of San Juan and the issuance of up to $361 million of securitized bonds when the plant is closed in 2022. By the end of April, a ruling is expected on purchased-power agreements for 410 megawatts of solar and battery storage capacity. By the start of October, a decision is expected on PNM's request to build 280 mw of gas-fired capacity and 70 mw of battery storage—a $278 million investment.

Our 2020 earnings estimate requires an explanation. The first quarter fell into the red due to sizable unrealized losses ($0.37 a share) on the company's decommissioning and reclamation trusts. We *include* these items even though PNM Resources excludes them from its targeted range of $2.16-$2.26 a share. Aside from this, the weak economy will hurt commercial kilowatt-hour sales. However, PNM Resources has stated that its guidance will be hard to attain if the shutdowns last well beyond the end of May.

PNM's next rate case might be delayed. The utility had planned to file in the current quarter, but it re-evaluating this in view of the worsening economy. Any significant delay in filing will likely affect the company's earning power in 2021. Even so, we expect earnings to advance solidly next year, assuming the economy will be in better shape.

The company sold stock under a forward sale. This occurred in early 2020, before the market downturn. The issuance of 6.18 million shares will raise $290 million when exercised, probably in late 2020.

PNM Resources stock has a low dividend yield, by utility standards. In fact, the yield is equal to the median of all dividend-paying stocks under our coverage. The equity does not stand out for total return potential, either for the 18-month or 3- to 5-year period.

Paul E. Debbas, CFA *April 24, 2020*

(A) Dil. EPS. Excl. nonrec. gain (losses): '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢); '18, (59¢); '19, ($1.31). Excl. gains from disc. ops.: '08, 42¢; '09, 78¢. '17 EPS don't sum due to rounding. Next egs. report due late July. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $11.81/sh. (D) In mill., adj. for split. (E) Rate base: net orig. cost. Rate all'd on com. eq. in NM in '18: 9.575%; in TX in '11: 10.125%; earned on avg. com. eq., '19: 10.2%. Regulatory Climate: NM, Below Avg.; TX, Avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	75

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PPL CORPORATION NYSE-PPL

RECENT PRICE 24.96 | P/E RATIO 10.4 (Trailing: 10.5 Median: 13.0) | RELATIVE P/E RATIO 0.63 | DIV'D YLD 6.7% | VALUE LINE

TIMELINESS 3 Lowered 4/3/20
SAFETY 2 Raised 8/21/15
TECHNICAL 3 Lowered 4/10/20
BETA 1.05 (1.00 = Market)

High:	34.4	33.1	30.3	30.2	33.6	38.1	36.7	39.9	40.2	32.5	36.3	36.8
Low:	24.3	23.8	24.1	26.7	28.4	29.4	29.2	32.1	30.7	25.3	27.8	18.1

18-Month Target Price Range

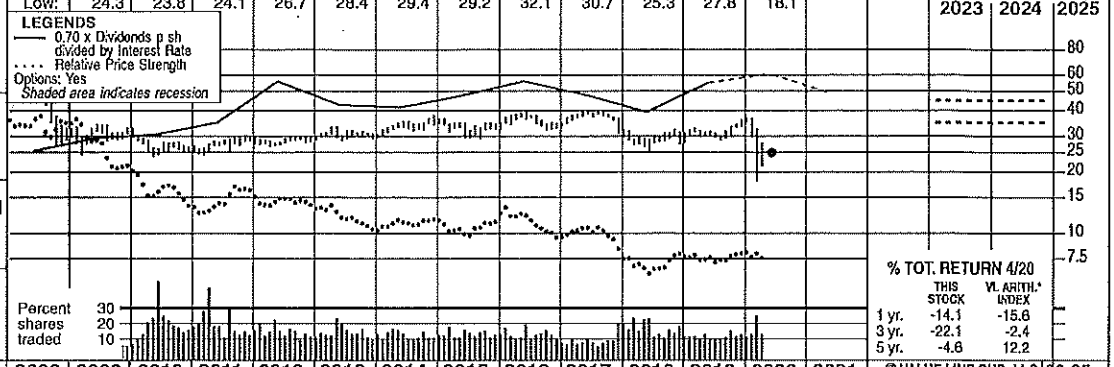
Low-High	Midpoint (% to Mid)
$22-$42	$32 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+80%)	20%
Low	35	(+40%)	14%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	374	390	425
to Sell	358	335	349
Hld's(000)	522107	514363	526640



% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.1	-15.6
3 yr.	-22.1	-2.4
5 yr.	-4.6	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
15.37	16.36	17.92	17.41	21.47	20.03	17.63	22.02	21.11	18.82	17.27	11.38	11.06	10.74	10.81	10.13	*10.30*	*10.45*	Revenues per sh	*11.25*
3.59	3.84	4.26	5.10	4.71	3.47	3.66	4.59	4.84	4.64	4.58	3.78	4.28	3.68	4.16	3.94	*4.20*	*4.35*	"Cash Flow" per sh	*5.00*
1.87	1.92	2.29	2.63	2.45	1.19	2.29	2.61	2.61	2.38	2.38	2.37	2.79	2.11	2.58	2.37	*2.40*	*2.45*	Earnings per sh A	*2.75*
.82	.96	1.10	1.22	1.34	1.38	1.40	1.40	1.44	1.47	1.49	1.50	1.52	1.58	1.64	1.65	*1.66*	*1.67*	Div'd Decl'd per sh B ■	*1.80*
1.94	2.13	3.62	4.51	3.79	3.25	3.30	4.30	5.34	6.68	6.14	5.24	4.30	4.52	4.50	4.02	*4.35*	*4.05*	Cap'l Spending per sh	*3.25*
11.21	11.62	13.30	14.88	13.55	14.57	16.98	18.72	18.01	19.78	20.47	14.72	14.56	15.52	16.18	16.93	*17.75*	*18.55*	Book Value per sh C	*21.25*
378.14	380.15	385.04	373.27	374.58	377.18	483.39	578.41	581.94	630.32	665.85	673.86	679.73	693.40	720.32	767.23	*771.00*	*775.00*	Common Shs Outst'g D	*780.00*
12.5	15.1	14.1	17.3	17.6	25.7	11.9	10.5	10.9	12.8	14.1	13.9	12.8	17.6	11.3	13.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.66	.80	.76	.92	1.06	1.71	.76	.66	.69	.72	.74	.70	.67	.89	.61	.72	*Value Line*		Relative P/E Ratio	*.80*
3.5%	3.3%	3.4%	2.7%	3.1%	4.5%	5.1%	5.1%	5.1%	4.8%	4.4%	4.5%	4.2%	4.2%	5.6%	5.2%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $23044 mill. Due in 5 Yrs $8357 mill.
LT Debt $20721 mill. LT Interest $867 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 3.2x)

Leases, Uncapitalized Annual rentals $29 mill.
Pension Assets-12/19 $12530 mill. Oblig $12661 mill.

Pfd Stock None
Common Stock 767,813,625 shs. as of 1/31/20
MARKET CAP: $19 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
8521.0	12737	12286	11860	11499	7669.0	7517.0	7447.0	7785.0	7769.0	*7950*	*8100*	Revenues ($mill)	*8800*
1009.0	1456.0	1536.0	1541.0	1583.0	1603.0	1902.0	1449.0	1827.0	1746.0	*1860*	*1895*	Net Profit ($mill)	*2100*
22.0%	31.0%	26.2%	23.1%	33.0%	22.5%	25.4%	24.2%	20.0%	19.0%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
3.5%	4.0%	4.1%	3.7%	2.8%	1.6%	1.6%	1.9%	2.0%	1.9%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
59.0%	61.9%	64.1%	62.3%	58.0%	65.2%	64.3%	64.8%	63.3%	61.5%	*60.0%*	*59.5%*	Long-Term Debt Ratio	*57.5%*
39.8%	37.2%	35.9%	37.7%	42.0%	34.8%	35.7%	35.2%	36.7%	38.5%	*40.0%*	*40.5%*	Common Equity Ratio	*42.5%*
20621	29071	29205	33058	32484	28482	27707	30608	31726	33712	*34325*	*35550*	Total Capital ($mill)	*39200*
20858	27266	30032	33087	34597	30382	30074	33092	34458	36482	*38475*	*40150*	Net Plant ($mill)	*42900*
6.1%	6.5%	7.0%	6.2%	6.5%	7.1%	8.4%	6.2%	7.2%	6.6%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
11.9%	13.1%	14.7%	12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	*13.5%*	*13.0%*	Return on Shr. Equity	*12.5%*
12.0%	13.3%	14.6%	12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	*13.5%*	*13.0%*	Return on Com Equity E	*12.5%*
5.2%	6.4%	6.7%	5.3%	4.5%	6.0%	8.8%	3.5%	6.0%	4.3%	*4.5%*	*4.0%*	Retained to Com Eq	*4.0%*
58%	52%	54%	57%	61%	63%	54%	74%	62%	68%	*69%*	*68%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-1.5	+2.0	-3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	336	292	283

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-6.0%	-11.0%	*1.0%*
"Cash Flow"	-1.0%	-3.5%	*4.0%*
Earnings	1.0%	-1.0%	*2.5%*
Dividends	2.0%	2.0%	*2.0%*
Book Value	1.0%	-3.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1951	1725	1845	1926	7447.0
2018	2126	1848	1872	1939	7785.0
2019	2079	1803	1933	1954	7769.0
2020	*2150*	*1850*	*2000*	*1950*	*7950*
2021	*2200*	*1900*	*2050*	*1950*	*8100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.59	.43	.51	.58	2.11
2018	.65	.73	.62	.57	2.58
2019	.64	.60	.65	.48	2.37
2020	*.70*	*.55*	*.60*	*.55*	*2.40*
2021	*.65*	*.60*	*.65*	*.55*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.3775	.38	.38	.38	1.52
2017	.38	.395	.395	.395	1.57
2018	.395	.41	.41	.41	1.63
2019	.41	.4125	.4125	.4125	1.65
2020	.4125	.415			

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to 1.4 million customers in eastern & central PA. Acq'd Kentucky Utilities and Louisville Gas and Electric (1.3 mill. customers) 11/10. Has electric distribution sub. in U.K. (7.9 mill. customers). Sold gas distribution subsidiary in '08. Spun off power-generating subsidiary in '15. The company no longer breaks out data on electric operating statistics. Fuel costs: 18% of revs. '19 reported depr. rate: 2.8%. Has 12,300 empls. Chairman & CEO: William H. Spence. President & COO: Vincent Sorgi. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

PPL Corporation has the highest dividend yield of any electric utility stock under our coverage, by far. This is nearly three percentage points above the utility average. The share price has fallen 30% so far this year, much more than most utility equities. Investors are concerned about a negative shift in exchange rates between the dollar and the British pound, which will affect reported income from PPL's utilities in the United Kingdom. In fact, due to the company's revised expectation for exchange rates, management reduced its 2021 earnings guidance from $2.50-$2.80 a share to $2.40-$2.60. PPL's U.K. business is mostly hedged for 2020, but not for 2021.

Apart from exchange rates, investors have concerns about the long-term earning power of the U.K. operations. A new regulatory scheme will take effect in April of 2023, and it might well be less favorable for the company than the current plan. The performance of PPL stock so far this year indicates that the market's worries have not gone away.

We look for just slight growth in share net in 2020 and 2021. We think the weak economy will affect PPL's ntilities. In addition, average shares outstanding will be significantly higher because a forward stock sale was settled in November of 2019. Finally, the unfavorable move in exchange rates will hurt reported income from the portion of the U.K. business that is not hedged. Our estimate of $2.40 a share, which we reduced by $0.15 a share, is at the low end of PPL's targeted range of $2.40-$2.60. We cut our 2021 estimate by $0.20 a share, to $2.45.

The board of directors raised the dividend at its February meeting, effective with the April payment. The increase was a token one, a cent a share (0.6%) annually. The board's action was taken when the company had lowered its expectation for 2021, but before the state of the economy and the stock market plummeted. Even so, we think the payout will hold at the current level.

PPL stock has an attractive valuation compared with most utilities. Besides the lofty dividend yield, total return potential is better than most other utilities for the 18-month and 3- to 5-year periods.

Paul E. Debbas, CFA *May 15, 2020*

(A) Diluted EPS. Excl. nonrec. gain (losses): '07, (12¢); '10, (8¢); '11, 8¢; '13, (62¢); gains (losses) on disc. ops.: '07, 19¢; '08, 3¢; '09, (10¢); '10, (4¢); '12, (1¢); '14, 23¢; '15, ($1.36). '18 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds paid in early Jan., Apr., July, & Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '19: $7.08/sh. (D) In mill., adj. for split. (E) Rate base: Fair value. Rate all'd on com. eq. in PA in '16: none spec.; in KY in '19: 9.725%; earned on avg. com. eq., '19: 14.3%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	15
Earnings Predictability	70

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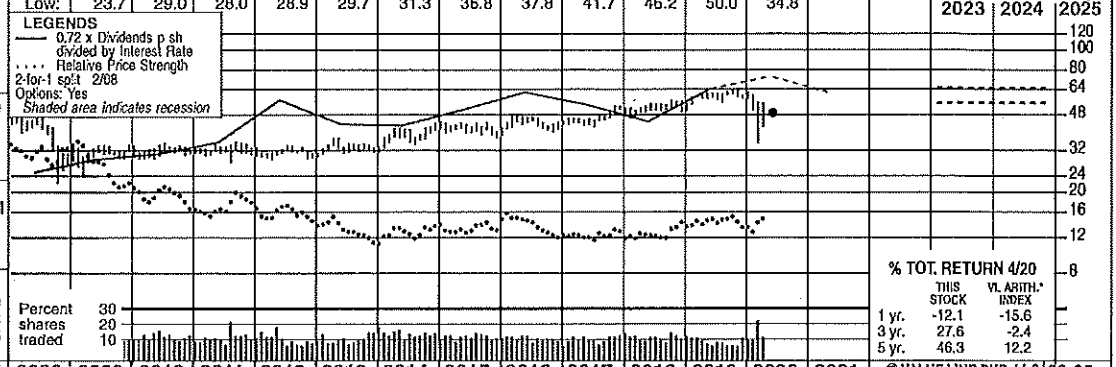
P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE 49.14 | P/E RATIO 15.4 (Trailing: 14.5 Median: 14.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 2 Raised 4/10/20
SAFETY 1 Raised 11/23/12
TECHNICAL 4 Raised 5/8/20
BETA .90 (1.00 = Market)

High:	34.1	34.9	35.5	34.1	37.0	43.8	44.4	47.4	53.3	56.7	63.9	62.1
Low:	23.7	29.0	28.0	28.9	29.7	31.3	36.8	37.8	41.7	46.2	50.0	34.8



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$38-$80	$59 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+30%)	11%
Low	55	(+10%)	7%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	364	336	415
to Sell	352	365	315
Hld's(000)	353668	353397	351159

Target Price Range
2023 | 2024 | 2025

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.1	-15.6
3 yr.	27.6	-2.4
5 yr.	46.3	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
23.09	24.74	24.07	25.28	27.94	24.57	23.31	22.42	19.33	19.71	21.52	20.61	18.22	18.14	19.24	19.99	*18.60*	*19.40*	Revenues per sh	*22.00*
3.02	3.42	3.91	4.36	4.68	4.98	5.27	5.36	4.87	5.17	5.82	6.15	5.07	5.30	5.44	6.76	*6.15*	*6.60*	"Cash Flow" per sh	*7.50*
1.52	1.79	1.85	2.59	2.90	3.08	3.07	3.11	2.44	2.45	2.99	3.30	2.83	2.82	2.76	3.90	*3.20*	*3.55*	Earnings per sh A	*4.25*
1.10	1.12	1.14	1.17	1.29	1.33	1.37	1.37	1.42	1.44	1.48	1.56	1.64	1.72	1.80	1.88	*1.96*	*2.04*	Div'd Decl'd per sh B ■†	*2.30*
2.64	2.04	2.01	2.65	3.50	3.55	4.27	4.12	5.09	5.56	5.58	7.65	8.32	8.30	7.76	6.28	*5.65*	*5.25*	Cap'l Spending per sh	*5.25*
12.05	11.99	13.35	14.35	15.36	17.37	19.04	20.30	21.31	22.95	24.09	25.66	26.01	27.42	28.53	29.94	*31.15*	*32.70*	Book Value per sh C	*38.00*
476.20	502.33	505.29	508.52	506.02	505.99	505.97	505.95	505.89	505.86	505.84	505.28	504.87	505.00	504.00	504.00	*505.00*	*505.00*	Common Shs Outst'g D	*505.00*
14.3	16.5	17.8	16.5	13.6	10.0	10.4	10.4	12.8	13.5	12.6	12.4	15.3	16.3	18.7	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.76	.88	.96	.88	.82	.67	.66	.65	.81	.76	.66	.62	.80	.82	1.01	.81	*Value Line*		Relative P/E Ratio	*.80*
5.1%	3.8%	3.5%	2.7%	3.3%	4.3%	4.3%	4.2%	4.6%	4.4%	3.9%	3.8%	3.8%	3.7%	3.5%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $16767 mill. Due in 5 Yrs $8130 mill.
LT Debt $14040 mill. LT Interest $527 mill.
(LT interest earned: 5.2x)

Leases, Uncapitalized Annual rentals $44 mill.

Pension Assets-12/19 $5929 mill.
Oblig $6892 mill.

Pfd Stock None

Common Stock 505,625,328 shs.
as of 4/21/20
MARKET CAP: $25 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
11793	11343	9781.0	9968.0	10886	10415	9198.0	9161.0	9696.0	10076	*9400*	*9800*	Revenues ($mill)	*11150*
1557.0	1577.0	1239.0	1243.0	1518.0	1679.0	1436.0	1431.0	1399.0	1979.0	*1625*	*1810*	Net Profit ($mill)	*2125*
40.5%	40.4%	36.2%	39.5%	38.2%	37.4%	31.7%	37.3%	22.3%	15.9%	*9.0%*	*9.0%*	Income Tax Rate	*9.0%*
5.5%	2.7%	4.8%	4.6%	4.5%	5.5%	8.4%	10.6%	9.8%	5.5%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
44.8%	42.1%	38.3%	40.4%	40.4%	40.3%	45.3%	46.6%	47.8%	47.7%	*48.0%*	*48.5%*	Long-Term Debt Ratio	*50.0%*
55.2%	57.9%	61.7%	59.6%	59.6%	59.7%	54.7%	53.4%	52.2%	52.3%	*52.0%*	*51.5%*	Common Equity Ratio	*50.0%*
17452	17731	17467	19470	20446	21900	24025	25915	27545	28832	*30375*	*32150*	Total Capital ($mill)	*38500*
16390	17849	19736	21645	23589	26539	29286	31797	34363	35844	*37300*	*38475*	Net Plant ($mill)	*41700*
10.4%	10.2%	8.1%	7.5%	8.4%	8.6%	6.8%	6.4%	6.0%	7.8%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
16.2%	15.4%	11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	9.7%	13.1%	*10.5%*	*11.0%*	Return on Shr. Equity	*11.0%*
16.2%	15.4%	11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	9.7%	13.1%	*10.5%*	*11.0%*	Return on Com Equity E	*11.0%*
9.0%	8.6%	4.8%	4.4%	6.3%	6.8%	4.6%	4.1%	3.4%	6.8%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
45%	44%	58%	59%	49%	47%	58%	61%	65%	48%	*61%*	*57%*	All Div'ds to Net Prof	*54%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.0	+2.8	-2.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	9567	9978	9753
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	503	413	361

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-3.0%	-1.0%	*2.5%*
"Cash Flow"	2.0%	2.0%	*4.5%*
Earnings	1.0%	4.0%	*5.0%*
Dividends	3.5%	4.5%	*4.0%*
Book Value	6.0%	4.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2647	2155	2263	2096	9161.0
2018	2818	2016	2394	2468	9696.0
2019	2980	2316	2302	2478	10076
2020	2781	*2019*	*2200*	*2400*	*9400*
2021	*2900*	*2100*	*2300*	*2500*	*9800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.94	.69	.78	.42	2.82
2018	1.10	.53	.81	.32	2.76
2019	1.38	.86	.80	.86	3.90
2020	.88	*.72*	*.95*	*.65*	*3.20*
2021	*1.15*	*.75*	*1.00*	*.65*	*3.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.41	.41	.41	.41	1.64
2017	.43	.43	.43	.43	1.72
2018	.45	.45	.45	.45	1.80
2019	.47	.47	.47	.47	1.88
2020	.49				

BUSINESS: Public Service Enterprise Group Incorporated is a holding company for Public Service Electric and Gas Company (PSE&G), which serves 2.3 million electric and 1.8 million gas customers in New Jersey, and PSEG Power LLC, a nonregulated power generator with nuclear, gas, and coal-fired plants in the Northeast. PSEG Energy Holdings is involved in renewable energy. The company no longer breaks out data on electric and gas operating statistics. Fuel costs: 33% of revenues. '19 reported depreciation rates (utility): 1.9%-2.5%. Has 13,000 employees. Chairman, President & Chief Executive Officer: Dr. Ralph Izzo. Inc.: New Jersey. Address: 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101-1171. Telephone: 973-430-7000. Internet: www.pseg.com.

Investors should not be overly worried about the modest earnings decline we estimate for Public Service Enterprise Group this year. In 2019, mark-to-market accouuting gains and unrealized gains on the company's nuclear decommissioning trusts boosted pretax income by a total of $540 million. These two items swung to a deficit of $112 million in the first quarter of 2020. Although PSEG excludes these items from its 2020 earnings guidance of $3.30-$3.50 a share, we include them because they are an ongoing part of the company's results. Management has not changed its expectations for its businesses this year, despite the decline in kilowatt-hour sales stemming from the weak economy. PSEG has initiated cost-cutting measures to offset the effects of the current economic troubles.

The company's utility subsidiary, Public Service Electric and Gas, should continue to increase its earnings despite a fall in electric sales. Weather-adjusted electric volume fell 5%-7% from late March through April. As mentioned above, cost-reduction measures should compensate for this. Also, some of PSE&G's income comes from electric transmission, which has a growing rate base and is not affected by a decline in volume. And the utility has programs to modernize its gas system and make its electric and gas systems more resilient, and most of these expenditures are recoverable without the need to file a general rate case. Growth from PSE&G should enable earnings to advance in 2021.

PSEG Power, the main nonutility subsidiary, is dealing with difficult market conditions. The merchant-power producer is experiencing lower output and margins. The company is addressing the tough climate by hedging its output. A full year of zero-emission credits from New Jersey (to subsidize the company's nuclear units) will help. And PSEG Power has additional capacity from gas-fired generating units that began operating last year.

This timely and top-quality stock has a dividend yield that is about average for a utility. The price is down 17% this year, in line with many utility issues. Total return potential doesn't stand out for the 18-month or 3- to 5-year period.

Paul E. Debbas, CFA *May 15, 2020*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '06, (35¢); '08, (96¢); '09, 6¢; '11, (34¢); '12, 7¢; '16, (30¢); '17, 28¢ (net); '18, 8¢; '19, (62¢); gains (loss) from disc. ops.: '05, (33¢); '06, 12¢; '07, 3¢; '08, 40¢; '11, 13¢. '17 EPS don't sum due to rounding. Next egs. report due early Aug. (B) Div'ds histor. paid in late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $7.59/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '18: 9.6%; earned on avg. com. eq., '19: 13.2%. Regul. Climate: Avg.

Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	70

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SCANA CORP. NYSE-SCG

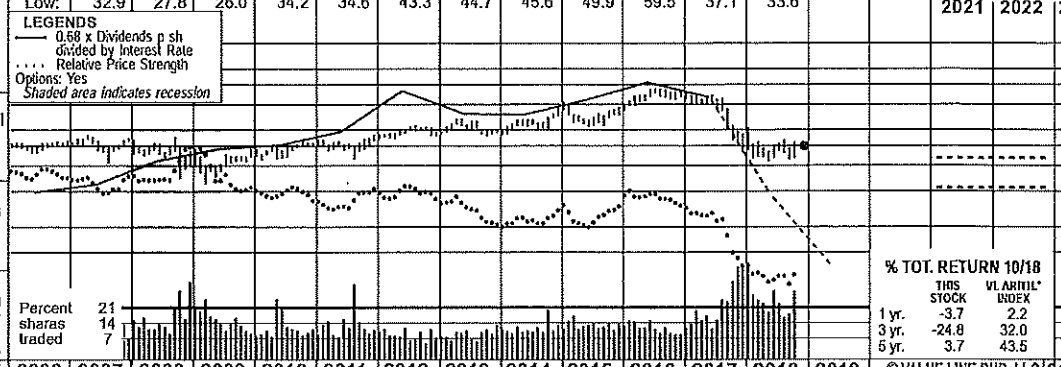
RECENT PRICE 40.05 | P/E RATIO 31.8 (Trailing: 14.7 Median: 14.0) | RELATIVE P/E RATIO 1.90 | DIV'D YLD 1.2- 0/ Nil /0 | VALUE LINE

TIMELINESS 4 Lowered 5/4/18
SAFETY 3 Lowered 10/13/17
TECHNICAL 4 Raised 11/16/18
BETA .65 (1.00 = Market)

High:	45.5	44.1	38.6	42.0	45.5	50.3	54.4	63.4	65.6	76.4	74.1	49.4	
Low:	32.9	27.8	26.0	34.2	34.6	43.3	44.7	45.6	49.9	59.5	37.1	33.6	

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.68 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(-15%)	-1%
Low	25	(-40%)	-9%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	5	0	0	3	0	0	4	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2017	1Q2018	2Q2018
to Buy	207	222	187
to Sell	222	253	231
Hld's(000)	100765	97437	100076

% TOT. RETURN 10/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.7	2.2
3 yr.	-24.8	32.0
5 yr.	3.7	43.5

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
26.65	30.85	34.53	41.86	39.11	39.61	45.16	34.35	36.10	33.95	31.63	31.88	34.70	30.65	29.58	30.82	*27.60*	*27.25*	Revenues per sh	*29.25*
4.56	4.95	5.28	7.43	5.68	5.73	5.86	5.63	5.91	6.01	6.30	6.53	6.91	6.70	7.28	7.35	*5.10*	*4.75*	"Cash Flow" per sh	*5.75*
2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.85	2.98	2.97	3.15	3.39	3.79	3.81	4.16	4.20	*1.80*	*1.25*	Earnings per sh A	*1.75*
1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.90	1.94	1.98	2.03	2.10	2.18	2.30	2.45	*.98*	*.49*	Div'd Decl'd per sh B ■ †	*.70*
6.41	6.94	4.86	3.38	4.52	6.21	7.68	7.41	6.87	6.81	8.16	7.84	7.65	8.07	11.05	8.57	*6.10*	*6.05*	Cap'l Spending per sh	*6.50*
19.64	20.82	21.78	23.35	24.39	25.37	25.85	27.63	29.05	29.94	31.47	33.08	34.95	38.09	40.06	36.75	*37.55*	*38.35*	Book Value per sh C	*41.25*
110.83	110.74	112.52	114.67	116.67	116.67	117.78	123.34	127.45	129.88	132.01	141.00	142.70	142.90	142.90	143.00	*143.00*	*143.00*	Common Shs Outst'g D	*143.00*
12.2	13.0	13.6	14.4	15.4	15.0	12.7	11.6	12.9	13.7	14.8	14.4	13.7	14.7	16.8	14.5	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.67	.74	.72	.77	.83	.80	.76	.77	.82	.86	.94	.81	.72	.74	.88	.73	*Value Line*		Relative P/E Ratio	*.95*
4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	5.7%	4.9%	4.8%	4.2%	4.2%	4.1%	3.9%	3.3%	4.0%	*estimates*		Avg Ann'l Div'd Yield	*2.3%*

CAPITAL STRUCTURE as of 9/30/18
Total Debt $7067 mill. Due in 5 Yrs $2200mill.
LT Debt $6735 mill. LT Interest $368 mill.
(LT interest earned: 2.5x)

Leases, Uncapitalized Annual rentals $34 mill.
Pension Assets-12/17 $849.6 mill. Oblig $933.2 mill.

Pfd Stock None

Common Stock 142,619,243 shs.
as of 10/26/18
MARKET CAP: $5.7 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
5319.0	4237.0	4601.0	4409.0	4176.0	4495.0	4951.0	4380.0	4227.0	4407.0	*3950*	*3900*	Revenues ($mill)	*4200*
353.0	357.0	376.0	387.0	420.0	471.0	538.0	544.0	595.0	601.0	*255*	*180*	Net Profit ($mill)	*260*
35.4%	32.0%	29.8%	30.3%	30.2%	32.1%	31.6%	31.8%	31.3%	32.2%	*23.5%*	*23.5%*	Income Tax Rate	*23.5%*
8.5%	14.3%	8.0%	5.4%	7.6%	8.7%	9.1%	7.7%	8.1%	6.8%	*10.0%*	*11.0%*	AFUDC % to Net Profit	*8.0%*
58.0%	56.8%	52.9%	54.3%	54.4%	53.6%	52.6%	51.9%	53.1%	52.9%	*55.5%*	*53.5%*	Long-Term Debt Ratio	*53.5%*
40.5%	43.2%	47.1%	45.7%	45.6%	46.4%	47.4%	48.1%	46.9%	47.1%	*44.5%*	*46.5%*	Common Equity Ratio	*46.5%*
7519.0	7891.0	7854.0	8511.0	9103.0	10059	10518	11325	12198	11161	*12075*	*11800*	Total Capital ($mill)	*12700*
8305.0	9009.0	9662.0	10047	10896	11643	12232	13425	14324	10648	*11050*	*11400*	Net Plant ($mill)	*12500*
6.2%	6.1%	6.5%	6.2%	6.3%	6.2%	6.6%	6.2%	6.3%	7.0%	*3.5%*	*3.0%*	Return on Total Cap'l	*3.5%*
11.2%	10.5%	10.2%	10.0%	10.1%	10.1%	10.8%	10.0%	10.4%	11.4%	*5.0%*	*3.5%*	Return on Shr. Equity	*4.5%*
11.4%	10.2%	10.2%	10.0%	10.1%	10.1%	10.8%	10.0%	10.4%	11.4%	*5.0%*	*3.5%*	Return on Com Equity E	*4.5%*
4.4%	3.6%	3.8%	3.6%	3.9%	4.1%	4.9%	4.3%	4.7%	4.9%	*2.0%*	*2.0%*	Retained to Com Eq	*2.5%*
62%	66%	63%	64%	61%	60%	55%	57%	55%	57%	*55%*	*39%*	All Div'ds to Net Prof	*39%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.9	+1.6	-2.5
Avg. Indust. Use (MWH)	NA	7991	7959
Avg. Indust. Revs. per KWH (¢)	NA	7.07	7.20
Capacity at Year-end (Mw)	5234	5233	5233
Peak Load, Summer (Mw)	4970	4807	4701
Annual Load Factor (%)	NA	58.5	58.6
% Change Customers (yr-end)	+1.5	+1.6	+1.3
Fixed Charge Cov. (%)	323	319	313

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-3.0%	-2.0%	-.5%
"Cash Flow"	1.0%	3.0%	-3.5%
Earnings	4.0%	6.0%	-13.0%
Dividends	3.5%	3.5%	-18.0%
Book Value	4.5%	5.0%	1.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1389	967	1068	956	4380.0
2016	1172	905	1093	1057	4227.0
2017	1173	1001	1076	1157	4407.0
2018	1180	843	926	*1001*	*3950*
2019	*1050*	*850*	*950*	*1050*	*3900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.39	.69	1.04	.69	3.81
2016	1.23	.74	1.32	.87	4.16
2017	1.19	.85	1.15	1.01	4.20
2018	1.18	.06	.47	*.14*	*1.85*
2019	*.55*	*.10*	*.40*	*.20*	*1.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.5075	.525	.525	.525	2.08
2015	.525	.545	.545	.545	2.16
2016	.545	.575	.575	.575	2.27
2017	.575	.6125	.6125	.6125	2.41
2018	.6125	.6125	.1237	.1237	

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 723,000 customers in central, southern, and southwestern South Carolina. Supplies gas service to 1.4 million customers in North Carolina, South Carolina, and Georgia. Electric revenue breakdown: residential, 46%; commercial, 33%; industrial, 17%; other, 4%. Generating sources: coal, 35%; gas & oil, 33%; nuclear, 19%; hydro & other, 4%; purchased, 9%. Fuel costs: 40% of revenues. '17 reported depreciation rate: 2.6%. Has 5,200 employees. CEO: Jimmy Addison. Incorporated: South Carolina. Address: 100 SCANA Parkway, Cayce, South Carolina 29033. Telephone: 803-217-9000. Internet: www.scana.com.

SCANA stock has been weak of late due to the market's concerns about a possible unfavorable judicial ruling. Last year, the company's utility subsidiary, South Carolina Electric & Gas, canceled its nuclear construction project due to extensive cost overruns and delays. The utility had been recovering construction work in progress for this project thanks to the state's Base Load Review Act (BLRA). Recovering monies for a canceled project resulted in significant criticism from customers and politicians, and it appears as if a state judge is about to overturn the BLRA. This might result in a write-off of $5.0 billion for revenues SCE&G has collected for the project to date. Moreover, as of year-end 2017, the utility had $4 billion of unrecovered costs. Already, the state commission has reduced rates 15% through the end of 2018, and the regulators might make this cut permanent. This is why profits plummeted in the second and third quarters, and will be significantly lower this year.

An unfavorable court ruling would probably threaten the proposed acquisition of SCANA by Dominion Energy. This calls for Dominion to issue .669 of a share (valued at $47.28) for each share of SCANA. However, the recent price of its stock is 15% below the value of Dominion's offer. This indicates the market's expectation that the deal will fall through. Dominion has offered an alternative proposal for SCE&G's customers, but this might not be enough to win approval.

The board of directors slashed the dividend 80% earlier this year, and we don't rule out a suspension. The decision was made to correspond to the portion of the payout that is attributable to SCE&G's electric business. Further bad news might prompt the board to eliminate the payout, in our view. Even if the dividend holds at the current level, the yield is not high enough to appeal to income-oriented investors.

We advise investors to avoid this stock. It's true that shareholders will be amply rewarded if the Dominion acquisition goes through, but we think the potential reward is not worth the risk of additional rate reductions and/or refunds of previously collected revenues.

Paul E. Debbas, CFA *November 16, 2018*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢; '15, $1.41; '17, ($5.03). Next earnings report due late Feb. (B) Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intangibles. In '17: $39.02/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in SC: 10.25% elec. in '13, 10.25% gas in '05; in NC: 9.7% in '16; earned on avg. com. eq., '17: 10.3%. Regulatory Climate: Above Average.

Company's Financial Strength	B
Stock's Price Stability	75
Price Growth Persistence	30
Earnings Predictability	80

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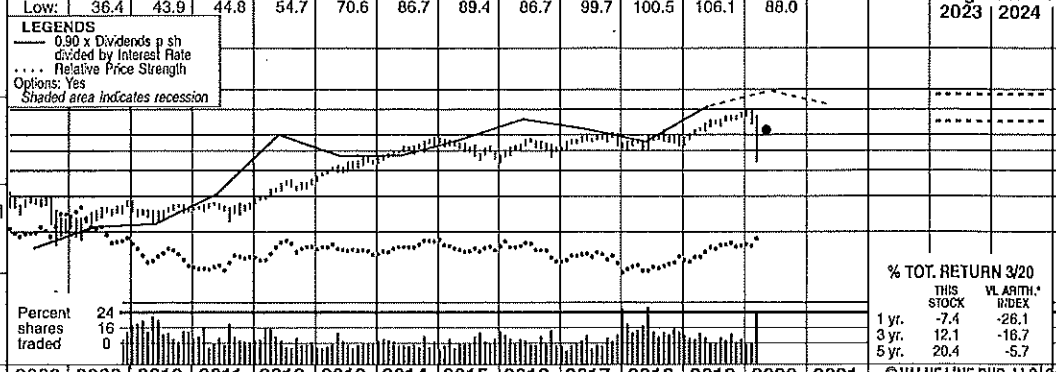
SEMPRA ENERGY NYSE-SRE

RECENT PRICE 126.98 | P/E RATIO 19.7 (Trailing: 21.3 Median: 20.0) | RELATIVE P/E RATIO 1.35 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 6/21/19
SAFETY 2 Raised 7/29/16
TECHNICAL 2 Raised 3/13/20
BETA .65 (1.00 = Market)

High:	57.2	57.2	56.0	72.9	93.0	116.3	116.2	114.7	123.0	127.2	154.5	161.9
Low:	36.4	43.9	44.8	54.7	70.6	86.7	89.4	86.7	99.7	100.5	106.1	88.0

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$120-$174	$147 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	190	(+50%)	13%
Low	140	(+10%)	6%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	338	368	424
to Sell	316	293	276
Hld's(000)	257637	253080	248880

Percent shares traded 24 16 0

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.4	-26.1
3 yr.	12.1	-16.7
5 yr.	20.4	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
40.18	45.64	44.89	43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.80	41.20	40.71	44.59	42.69	37.12	38.00	36.90	Revenues per sh	41.25
6.58	5.96	6.74	6.93	7.40	7.94	7.76	8.58	8.92	8.87	9.41	10.32	9.50	10.57	11.07	11.14	12.30	12.95	"Cash Flow" per sh	15.75
3.93	3.52	4.23	4.26	4.43	4.78	4.02	4.47	4.35	4.22	4.63	5.23	4.24	4.63	5.48	5.97	6.85	7.75	Earnings per sh A	9.50
1.00	1.16	1.20	1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	2.80	3.02	3.29	3.58	3.87	4.18	4.50	Div'd Decl'd per sh B ■	5.60
4.62	5.46	7.28	7.70	8.47	7.76	8.58	11.85	12.20	10.52	12.68	12.71	16.85	15.71	13.82	12.71	18.10	16.00	Cap'l Spending per sh	12.00
20.78	23.95	28.66	31.87	32.75	36.54	37.54	41.00	42.42	45.03	45.98	47.56	51.77	50.41	54.35	60.58	72.05	76.65	Book Value per sh C	88.25
234.18	257.19	262.01	261.21	243.32	246.51	240.45	239.93	242.37	244.46	246.33	248.30	250.15	251.36	273.77	291.71	300.00	325.00	Common Shs Outst'g D	340.00
8.6	11.8	11.5	14.0	11.8	10.1	12.6	11.8	14.9	19.7	21.9	19.7	24.4	24.3	20.4	22.5	Bold figures are		Avg Ann'l P/E Ratio	17.5
.45	.63	.62	.74	.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	1.22	1.10	1.21	Value Line		Relative P/E Ratio	.95
2.9%	2.8%	2.5%	2.1%	2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%	2.7%	2.9%	2.9%	3.2%	2.9%	estimates		Avg Ann'l Div'd Yield	3.4%

CAPITAL STRUCTURE as of 12/31/19
Total Debt $25816 mill. Due in 5 Yrs $10486 mill.
LT Debt $20785 mill. LT Interest $831 mill.
Incl. $1275 mill. capitalized leases.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $75 mill.
Pension Assets-12/19 $2662 mill. Oblig $3768 mill.
Pfd Stock $2278 mill. Pfd Div'd $142 mill.
17.25 mill. shs. 6% mandatorily convertible pfd.;
5.75 mill. shs. 6.75% mandatorily convertible pfd.;
811,073 shs. 6% cum., $25 par.
Common Stock 292,383,645 shs. as of 3/2/20
MARKET CAP: $37 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
9003.0	10036	9647.0	10557	11035	10231	10183	11207	11687	10829	11400	12000	Revenues ($mill)	14000
1008.0	1088.0	1079.0	1060.0	1162.0	1314.0	1065.0	1169.0	1607.0	1825.0	2300	2580	Net Profit ($mill)	3400
26.5%	25.3%	18.2%	26.5%	19.7%	19.2%	14.4%	24.5%	20.1%	17.9%	18.0%	18.0%	Income Tax Rate	18.0%
11.3%	15.2%	17.2%	11.2%	14.4%	15.3%	22.2%	21.9%	12.6%	10.0%	8.0%	7.0%	AFUDC % to Net Profit	6.0%
49.4%	50.4%	52.8%	50.5%	51.7%	52.6%	52.7%	56.4%	55.7%	51.0%	48.0%	48.5%	Long-Term Debt Ratio	48.5%
49.6%	49.2%	46.7%	49.4%	48.2%	47.3%	47.3%	43.5%	38.4%	43.4%	47.0%	51.5%	Common Equity Ratio	51.5%
18186	20015	22002	22281	23513	24963	27400	29135	38769	40734	46075	48550	Total Capital ($mill)	58300
19876	23572	25191	25460	25902	28039	32931	36503	36796	36452	40200	43625	Net Plant ($mill)	49900
6.8%	6.7%	6.1%	6.0%	6.1%	6.4%	5.0%	5.1%	5.1%	5.5%	6.0%	6.5%	Return on Total Cap'l	7.0%
10.9%	10.9%	10.4%	9.6%	10.2%	11.1%	8.2%	9.2%	9.4%	9.1%	9.0%	10.0%	Return on Shr. Equity	11.0%
11.1%	11.0%	10.4%	9.6%	10.3%	11.1%	8.2%	9.2%	10.0%	9.5%	9.5%	10.0%	Return on Com Equity E	11.0%
7.0%	6.5%	5.1%	4.1%	5.0%	5.8%	2.9%	3.3%	4.1%	3.9%	4.0%	4.0%	Retained to Com Eq	4.5%
37%	41%	52%	58%	52%	48%	65%	65%	62%	62%	64%	58%	All Div'ds to Net Prof	59%

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-.2	-3.2	-4.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.8	+.9	+.8
Fixed Charge Cov. (%)	264	186	181

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	.5%	-.5%	Nil
"Cash Flow"	4.0%	4.0%	6.5%
Earnings	2.0%	4.0%	10.0%
Dividends	10.0%	7.5%	7.5%
Book Value	5.0%	4.5%	8.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	3031	2533	2679	2964	11207
2018	2962	2564	2940	3221	11687
2019	2898	2230	2758	2943	10829
2020	3050	2350	2900	3100	11400
2021	3200	2500	3050	3250	12000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.75	1.20	.22	1.46	4.63
2018	1.43	1.27	1.23	1.55	5.48
2019	1.78	.85	2.00	1.34	5.97
2020	2.00	1.50	1.60	1.75	6.85
2021	2.25	1.75	1.80	1.95	7.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.70	.755	.755	.755	2.97
2017	.755	.8225	.8225	.8225	3.22
2018	.8225	.895	.895	.895	3.51
2019	.895	.9675	.9675	.9675	3.80
2020	.9675	1.045			

BUSINESS: Sempra Energy is a holding co. for San Diego Gas & Electric Company, which sells electricity & gas mainly in San Diego County, & Southern California Gas Company, which distributes gas to most of Southern California. Owns 80% of Oncor (acq'd 3/18), which distributes electricity in Texas. Customers: 5.2 million electric, 6.9 million gas. Electric revenue breakdown not available. Purchases most of its power; the rest is gas. Has nonutility subsidiaries, incl. IEnova (67% owned) in Mexico. Sold commodities business in '10. Power costs: 25% of revenues. '19 reported deprec. rates: 2.5%-6.6%. Has 14,000 employees. Chairman, President & CEO: Jeffrey W. Martin. Inc.: CA. Address: 488 8th Ave., San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

Sempra Energy expects to complete the sales of its South American utilities soon. These are the company's last transactions in a series of moves it made to make its strategic and geographic focus narrower. The sales will raise some $4.7 billion in cash, which will be earmarked for debt reduction. Sempra will record a gain on the sale (estimated at $1.81 billion-$1.96 billion after taxes). We will *exclude* this from our earnings presentation as income from discontinued operations. We will also exclude the income provided by these businesses (which Sempra estimates at $70 million-$85 million after taxes), even though the company includes this in its 2020 earnings guidance of $6.70-$7.50 a share.

Earnings are likely to advance significantly in 2020. San Diego Gas & Electric and Southern California Gas received rate increases of $134 million and $220 million, respectively, at the start of the year. Oncor, the 80%-owned utility in Texas, benefits from regulatory mechanisms that provide additional revenues annually. Sempra's subsidiary in Mexico is increasing its contribution. Even if the utilities see lower volume as the economy worsens, this should not affect the company's results because its utilities operate under a regulatory mechanism that decouples sales and revenues.

We expect another material profit increase in 2021. SDG&E and SoCalGas will benefit from rate increases of $102 million and $150 million, respectively. But the key factor will be the first full year of operation for a liquefied natural gas facility. This is expected to provide net profit of $400 million-$450 million annually. Sempra's contracts are long-term, take-or-pay with creditworthy counterparties. It takes no commodity or volumetric risk.

The board of directors raised the annual dividend $0.31 a share (8.0%). We project similar growth over the 3- to 5-year period. However, Sempra hasn't stated its dividend goals for beyond this year.

Sempra stock has an average yield for a utility. The share price has fallen 16%, more than most utilities, this year. It offers about average 18-month and 2023-2025 total return potential compared with other utility equities.

Paul E. Debbas, CFA *April 24, 2020*

(A) Diluted EPS. Excl. nonrec. gains (losses): '09, (26¢); '10, ($1.05); '11, $1.15; '12, (98¢); '13, (30¢); '15, 14¢; '16, $1.23; '17, (17¢); '18, ($2.06); '19, 16¢; gain (losses) from disc. ops.: '06, $1.21; '07, (10¢); '19, 95¢; '20, *$6.65*. Next earnings report due early May. (B) Div'ds paid mid-Jan., Apr., July, Oct. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '19: $13.37/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '20: 10.2%; SoCalGas in '20: 10.05%; earned on avg. com. eq., '19: 10.4%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	70

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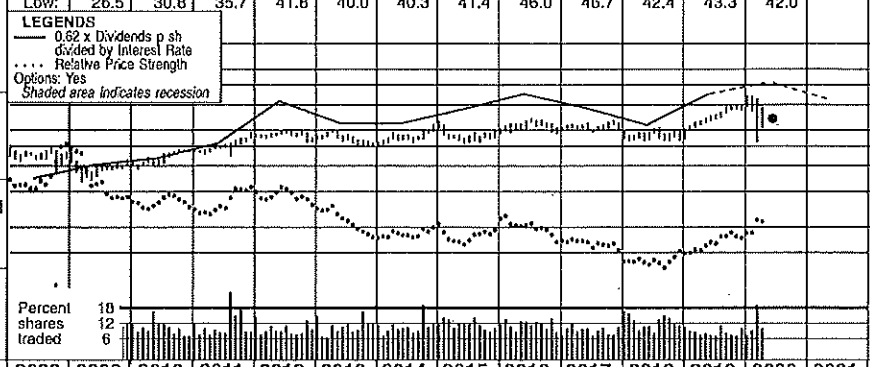
SOUTHERN COMPANY NYSE-SO

RECENT PRICE 54.92 | P/E RATIO 17.7 (Trailing: 17.0 Median: 16.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 3 Raised 3/2/18
SAFETY 2 Lowered 2/21/14
TECHNICAL 1 Raised 5/15/20
BETA .90 (1.00 = Market)

High:	37.6	38.6	46.7	48.6	48.7	51.3	53.2	54.6	53.5	49.4	64.3	71.1
Low:	26.5	30.8	35.7	41.8	40.0	40.3	41.4	46.0	46.7	42.4	43.3	42.0

Target Price Range 2023 | 2024 | 2025



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$40-$94	$67 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	10%
Low	50	(-10%)	3%

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	592	592	661
to Sell	507	531	564
Hld's(000)	612834	623889	633480

% TOT. RETURN 4/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.1	-15.6
3 yr.	30.0	-2.4
5 yr.	60.3	12.2

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	22.86	22.73	20.34	*18.85*	*19.80*	Revenues per sh	*22.75*
3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	6.64	6.41	6.33	*6.40*	*6.75*	"Cash Flow" per sh	*7.75*
2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	3.21	3.00	3.17	*3.10*	*3.25*	Earnings per sh A	*3.75*
1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	2.38	2.46	*2.54*	*2.62*	Div'd Decl'd per sh B ■	*2.86*
2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	7.37	7.74	7.17	*8.70*	*7.45*	Cap'l Spending per sh	*6.50*
13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	23.98	23.92	26.11	*26.65*	*27.30*	Book Value per sh C	*30.75*
741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	907.78	911.72	990.39	1007.6	1033.8	1053.3	*1060.0*	*1060.0*	Common Shs Outst'g D	*1090.0*
14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	15.5	15.1	17.6	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.78	.85	.87	.85	.97	.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.95	*Value Line*		Relative P/E Ratio	*.90*
4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%	5.3%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $47754 mill. Due in 5 Yrs $12821 mill.
LT Debt $44235 mill. LT Interest $1583 mill.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $289 mill.
Pension Assets-12/19 $14057 mill.
Oblig $14788 mill.
Pfd Stock $291 mill. Pfd Div'd $15 mill.
Incl. 10 mill. shs. 5.83% cum. pfd. ($25 stated value); 475,115 shs. 4.2%-5.44% cum. pfd. ($100 par).

Common Stock 1,055,955,711 shs.
MARKET CAP: $58 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
17456	17657	16537	17087	18467	17489	19896	23031	23495	21419	*20000*	*21000*	Revenues ($mill)	*24300*
2040.0	2268.0	2415.0	2439.0	2567.0	2647.0	2757.0	3269.0	3096.0	3354.0	*3310*	*3495*	Net Profit ($mill)	*4200*
33.5%	35.0%	35.6%	34.8%	33.8%	33.4%	28.5%	25.2%	21.3%	15.9%	*15.5%*	*15.5%*	Income Tax Rate	*15.5%*
13.7%	10.2%	9.4%	11.6%	13.9%	13.2%	11.9%	7.6%	6.8%	6.0%	*8.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
51.2%	50.0%	49.9%	51.5%	49.5%	52.8%	61.5%	64.5%	62.0%	60.1%	*60.5%*	*61.5%*	Long-Term Debt Ratio	*60.0%*
45.7%	47.1%	47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	*39.0%*	*38.0%*	Common Equity Ratio	*39.5%*
35438	37307	38653	41483	42142	46788	69359	68953	65750	69594	*72375*	*76125*	Total Capital ($mill)	*84300*
42002	45010	48390	51208	54868	61114	78446	79872	80797	83080	*88775*	*93025*	Net Plant ($mill)	*103500*
7.0%	7.2%	7.3%	6.8%	7.1%	6.6%	4.9%	5.9%	5.9%	6.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
11.8%	12.2%	12.5%	12.1%	12.1%	12.0%	10.3%	13.3%	12.4%	12.1%	*11.5%*	*12.0%*	Return on Shr. Equity	*12.5%*
12.2%	12.5%	12.8%	12.5%	12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	*11.5%*	*12.0%*	Return on Com Equity E	*12.5%*
3.0%	3.4%	3.6%	3.2%	3.2%	3.1%	2.5%	3.9%	2.6%	2.8%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
77%	73%	73%	75%	75%	76%	76%	72%	79%	77%	*82%*	*80%*	All Div'ds to Net Prof	*75%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.6	+3.6	-8.5
Avg. Indust. Use (MWH)	3016	3048	2947
Avg. Indust. Revs. per KWH (¢)	6.18	6.04	6.03
Capacity at Yearend (Mw)	46936	45824	41940
Peak Load, Summer (Mw) F	34874	36429	34209
Annual Load Factor (%)	61.4	61.2	60.3
% Change Customers (yr-end)	+1.0	+1.0	-8.9
Fixed Charge Cov. (%)	318	280	281

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	.5%	2.5%	*Nil*
"Cash Flow"	4.0%	4.5%	*3.0%*
Earnings	3.0%	3.0%	*3.0%*
Dividends	3.5%	3.5%	*3.0%*
Book Value	3.5%	3.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	5771	5430	6201	5629	23031
2018	6372	5627	6159	5337	23495
2019	5412	5098	5995	4914	21419
2020	5018	*4482*	*5500*	*5000*	*20000*
2021	*5200*	*4800*	*5800*	*5200*	*21000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.73	.73	1.08	.67	3.21
2018	.99	.71	1.13	.17	3.00
2019	.75	.85	1.25	.32	3.17
2020	.81	*.64*	*1.25*	*.40*	*3.10*
2021	*.85*	*.70*	*1.30*	*.40*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.5425	.56	.56	.56	2.22
2017	.56	.58	.58	.58	2.30
2018	.58	.60	.60	.60	2.38
2019	.60	.62	.62	.62	2.46
2020	.62	.64			

BUSINESS: The Southern Company, through its subs., supplies electricity to 4.3 mill. customers in GA, AL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.3 mill. customers in GA, NJ, IL, VA, & TN) 7/16. Sold Gulf Power 1/19. Electric rev. breakdown: residential, 37%; commercial, 30%; industrial, 19%; other, 14%. Retail revs. by state: GA, 56%; AL, 38%; MS, 6%. Generating sources: gas, 47%; coal, 20%; nuclear, 15%; other, 9%; purchased, 9%. Fuel costs: 34% of revs. '19 reported depr. rates (util.): 2.6%-3.7%. Has 27,900 empls. Chairman, Pres. and CEO: Thomas A. Fanning. Inc.: DE. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, GA 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

Southern Company's Georgia Power subsidiary believes it can complete its nuclear construction project on schedule and on budget, despite the disruption caused by coronavirus. The utility is adding two units (45.7%-owned) at the site of the Vogtle station. Units 3 and 4 are scheduled to be completed by November of 2021 and 2022, respectively. As of March 31st, the expected capital cost to complete the project was $2.2 billion. This includes the company's entire cost contingency, which is expected to absorb the effects of the coronavirus-related workforce reduction of 20%. But there is no margin for error in the construction cost if other unanticipated problems emerge.

The weak economy will hurt kilowatt-hour sales and the company's profitability. Management estimates a $250 million-$400 million reduction in margin, mostly in the second and third quarters. Accordingly, we have lowered our 2020 earnings estimate by $0.10 a share, to $3.10. This is the low end of Southern Company's targeted range of $3.10-$3.22, which was issued in February. At least the company is benefiting from rate increases at Georgia Power, Atlanta Gas Light, and Nicor Gas (in Illinois).

We estimate an earnings increase in a mid-single-digit range in 2021. The economy should be in better shape next year. Georgia Power will also benefit from the second phase ($181 million) of a three-year rate increase. Even so, we trimmed our estimate by $0.10 a share, as any economic growth will come of a lower base.

The board of directors raised the dividend in the second quarter. The increase was $0.02 a share (3.2%) quarterly, continuing the practice of the past three years. We project similar dividend growth over the 2023-2025 period.

Southern Company stock was the top performer in the electric utility industry in 2019, but has moved in line with the group so far this year. The price has declined 14%. The dividend yield is roughly one percentage point above the utility mean. However, total return potential for the 18-month and 3- to 5-year periods is unexciting. What's more, investors must be willing to accept the risks associated with the nuclear construction project.

Paul E. Debbas, CFA *May 15, 2020*

(A) Diluted EPS. Excl. nonrec. gain (losses): '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37); '18, (78¢); '19, $1.30. Next earnings report due late July. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. (C) Incl. def'd charges. In '19: $17.64/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on common equity (blended): 12.5%; earned on avg. com. eq., '19: 13.0%. Regulatory Climate: GA, AL Above Average; MS, FL Average. (F) Winter peak in '18.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	30
Earnings Predictability	85

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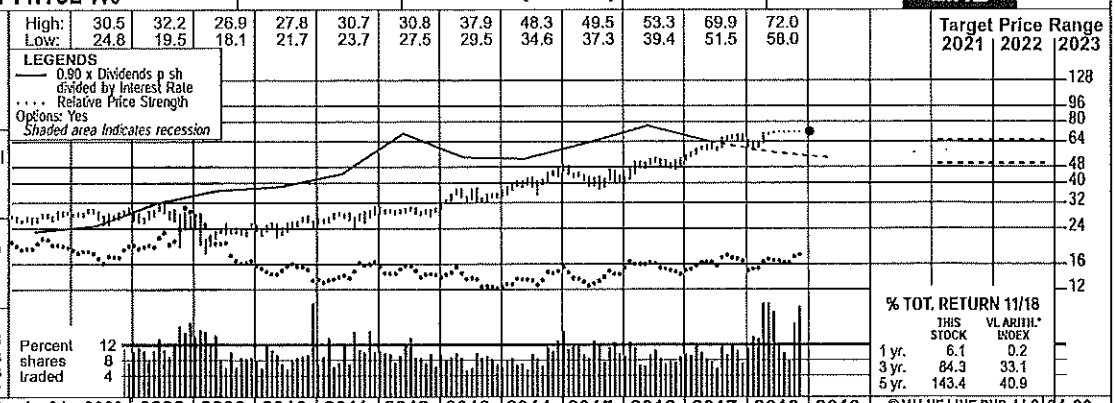
VECTREN CORP. NYSE-VVC

RECENT PRICE 71.91 | P/E RATIO 28.5 (Trailing: 27.3 Median: 17.0) | RELATIVE P/E RATIO 1.75 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS — G Suspended 5/4/18
SAFETY 2 Lowered 1/5/01
TECHNICAL — G Suspended 5/4/18
BETA .60 (1.00 = Market)

High:	30.5	32.2	26.9	27.8	30.7	30.8	37.9	48.3	49.5	53.3	69.9	72.0
Low:	24.8	19.5	18.1	21.7	23.7	27.5	29.5	34.6	37.3	39.4	51.5	58.0

Target Price Range 2021 | 2022 | 2023



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(-10%)	1%
Low	50	(-30%)	-5%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	4	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2018	2Q2018	3Q2018
to Buy	146	155	128
to Sell	178	185	158
Hld's(000)	55239	54724	53569

% TOT. RETURN 11/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.1	0.2
3 yr.	84.3	33.1
5 yr.	143.4	40.9

Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren.

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
30.67	25.76	26.06	28.39	27.16	30.23	31.62	29.40	29.53	32.02	31.75	33.05	Revenues per sh	39.55
3.97	4.40	4.44	4.71	5.03	5.03	5.33	5.48	5.69	5.93	5.95	6.50	"Cash Flow" per sh	7.85
1.63	1.79	1.65	1.73	1.94	1.66	2.02	2.39	2.55	2.60	2.45	2.85	Earnings per sh A	3.50
1.31	1.35	1.37	1.39	1.41	1.43	1.46	1.54	1.62	1.71	1.83	1.95	Div'd Decl'd per sh B■†	2.35
4.83	5.33	3.39	3.92	4.45	4.77	5.43	5.76	6.54	7.26	7.50	8.05	Cap'l Spending per sh	9.90
16.68	17.23	17.61	17.89	18.57	18.86	19.45	20.34	21.33	22.28	23.05	25.00	Book Value per sh C	29.05
81.03	81.10	81.70	81.90	82.20	82.40	82.60	82.80	82.90	83.00	83.50	84.00	Common Shs Outst'g D	86.00
16.8	12.9	15.0	15.8	15.0	20.7	20.0	17.9	19.2	23.5	Bold figures are		Avg Ann'l P/E Ratio	16.0
1.01	.86	.95	.99	.95	1.16	1.05	.90	1.01	1.15	Value Line		Relative P/E Ratio	.90
4.8%	5.9%	5.5%	5.1%	4.8%	4.2%	3.6%	3.6%	3.3%	2.8%	estimates		Avg Ann'l Div'd Yield	4.2%
2484.7	2088.9	2129.5	2325.2	2232.8	2491.2	2611.7	2434.7	2448.3	2657.3	2650	2775	Revenues ($mill)	3400
129.0	145.0	133.7	141.6	159.0	136.6	166.9	197.3	211.6	216.0	205	240	Net Profit ($mill)	300
37.1%	26.5%	35.8%	37.9%	34.2%	32.9%	32.7%	33.6%	34.8%	17.7%	21.0%	21.0%	Income Tax Rate	21.0%
2.9%	4.1%	--	--	--	--	--	--	4.1%	4.0%	4.0%	4.0%	AFUDC % to Net Profit	4.0%
48.0%	52.4%	49.9%	51.6%	50.4%	53.3%	46.7%	50.6%	47.3%	48.5%	51.0%	49.5%	Long-Term Debt Ratio	48.5%
52.0%	47.6%	50.1%	48.4%	49.6%	46.7%	53.3%	49.4%	52.7%	51.5%	49.0%	50.5%	Common Equity Ratio	51.5%
2599.5	2937.7	2874.1	3025.1	3079.5	3331.4	3013.9	3406.6	3358.0	3588.0	3925	4150	Total Capital ($mill)	4850
2720.3	2878.8	2955.4	3032.6	3119.6	3224.3	3439.0	4089.5	4406.8	4740.8	5000	5400	Net Plant ($mill)	6200
6.5%	6.3%	6.1%	6.2%	6.4%	5.4%	6.8%	7.0%	7.4%	7.0%	6.0%	6.5%	Return on Total Cap'l	7.0%
9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.4%	11.7%	12.0%	11.7%	10.5%	11.5%	Return on Shr. Equity	12.0%
9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.4%	11.7%	12.0%	11.7%	10.5%	11.5%	Return on Com Equity E	12.0%
2.0%	2.6%	1.6%	1.9%	2.9%	1.2%	2.9%	4.2%	4.4%	4.0%	2.5%	3.5%	Retained to Com Eq	4.0%
80%	75%	83%	80%	73%	86%	72%	65%	63%	66%	75%	68%	All Div'ds to Net Prof	67%

CAPITAL STRUCTURE as of 9/30/18
Total Debt $2364.2 mill. Due in 5 Yrs $644.1 mill.
LT Debt $1978.9 mill. LT Interest $80.0 mill.
(Total interest earned: 2.9x)

Pension Assets-12/17 $316.1 mill. Oblig. $366.5 mill.

Pfd Stock None

Common Stock 83,080,695 shs. as of 10/31/18

MARKET CAP: $6.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.4	+.3	-13.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1357	1360	1337
Peak Load, Summer (Mw)	1088	1096	1042
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.8	-.5
Fixed Charge Cov. (%)	428	446	363

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	1.0%	2.0%	4.5%
"Cash Flow"	3.5%	4.0%	5.5%
Earnings	4.0%	7.0%	5.5%
Dividends	3.0%	3.0%	6.5%
Book Value	3.0%	3.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.)F Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	706.2	551.0	573.5	604.0	2434.7
2016	584.8	533.7	631.0	699.0	2448.3
2017	624.5	630.7	691.2	710.9	2657.3
2018	658.4	644.3	665.0	682.3	2650
2019	650	660	720	745	2775

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	.69	.43	.48	.79	2.39
2016	.58	.39	.74	.84	2.55
2017	.67	.45	.75	.74	2.60
2018	.76	.42	.61	.66	2.45
2019	.70	.55	.78	.82	2.85

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.360	.360	.360	.380	1.46
2015	.380	.380	.380	.400	1.54
2016	.400	.400	.400	.420	1.62
2017	.420	.420	.420	.450	1.71
2018	.450	.450	.450	.480	

BUSINESS: Vectren Corp. is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two-thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base exceeding 1.1 million. 2017 Electricity revenues: residential, 38%; commercial, 29%; industrial, 31%; other, 2%. 2017 Gas revenues: residential, 67%; commercial, 22%; other, 11%. Nonutility operations include Infrastructure Services and Energy Services. Est'd plant age: electric, 10 years. '17 depreciation rate: 3.9%. Has about 5,500 employees. Chairman, President, & CEO: Carl L. Chapman. Incorporated: Indiana. Address: One Vectren Square, Evansville, Indiana 47708. Telephone: 812-491-4000. Internet: www.vectren.com.

Vectren Corporation's merger with CenterPoint Energy draws closer. Earlier in the year, the company agreed to be acquired by CenterPoint in a $6 billion deal. Vectren stockholders are to receive $72 in cash for each share owned. CenterPoint would assume all of Vectren's outstanding net debt. The deal has been unanimously approved by the boards of directors of both companies. Shareholders of Vectren have also given the nod. The Federal Energy Regulatory Commission (FERC) has approved the deal, as well.

Following the acquisition, CenterPoint Energy would be a leading energy delivery, infrastructure, and services company. It would have more than seven million customers and assets of about $29 billion. Considerably greater scale ought to allow for increased efficiency in the delivery of services. The combined entity would operate regulated utility businesses in eight states with a combined footprint in more than 40 states.

Vectren posted unimpressive results for the third quarter. The company reported a top-line decline of about 4%, on a year-over-year basis. Share net of $0.61 were no match for the prior-year tally. Our bottom-line presentation includes $8.8 million ($0.10 per share) in expenses related to the upcoming merger with CenterPoint Energy. Excluding these charges, earnings per share would have been $0.71. A measure of unevenness will likely persist in the near term. But on a stand-alone basis, we expect growth to resume in 2019. Ongoing investment in gas infrastructure programs in both Indiana and Ohio ought to drive growth at the utility group. Elsewhere, the company's infrastructure services and energy services businesses should benefit from healthy demand.

The board has increased the dividend nearly 7%. Beginning with the December payout, the quarterly dividend is now $0.48 per share. The dividend will likely increase at a good pace going forward.

Subscribers should look elsewhere at this time. The shares are trading close to the price that CenterPoint Energy will likely pay to acquire Vectren. On its own, this equity lacks appreciation potential for the pull to early next decade, and the dividend yield does not stand out for a utility.

Michael Napoli, CFA *December 14, 2018*

(A) Diluted EPS. Excl. nonrecur. gain (loss): '09, 15¢. Next egs report due late February.
(B) Div'ds historically paid in early March, June, September, and December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '17, $8.56/sh. (D) In millions. (E) Electric rate base determination: fair value. Rates allowed on elect. common equity range from 10.15% to 10.4%. Regulatory Climate: Above Average. (F) Totals may not sum due to rounding. (G) Unranked due to pending merger.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	80

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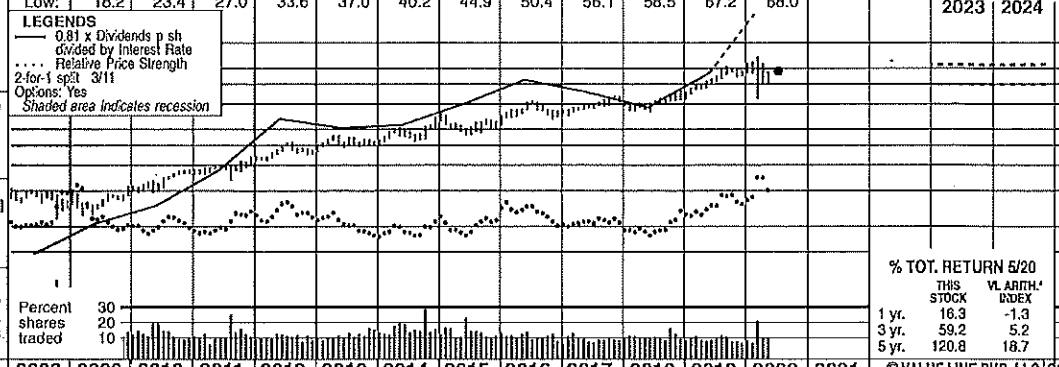
WEC ENERGY GROUP NYSE-WEC

RECENT PRICE 93.13 | P/E RATIO 24.8 (Trailing: 25.3 Median: 18.0) | RELATIVE P/E RATIO 1.26 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Lowered 6/16/19
SAFETY 1 Raised 3/23/12
TECHNICAL 1 Raised 4/24/20
BETA .80 (1.00 = Market)

High:	25.3	30.5	35.4	41.5	45.0	55.4	58.0	66.1	70.1	75.5	98.2	109.5
Low:	18.2	23.4	27.0	33.6	37.0	40.2	44.9	50.4	56.1	58.5	67.2	68.0

LEGENDS
— 0.81 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/11
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

16-Month Target Price Range

Low-High	Midpoint (% to Mid)
$65-$150	$108 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+5%)	5%
Low	80	(-15%)	Nil

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	392	403	383
to Sell	359	361	426
Hld's(000)	246256	246035	234743

Percent shares traded 30 20 10

% TOT. RETURN 5/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.3	-1.3
3 yr.	59.2	5.2
5 yr.	120.8	18.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
14.66	16.31	17.08	18.12	18.95	17.65	17.98	19.46	18.54	20.00	22.16	18.77	23.68	24.24	24.34	23.85	*22.20*	*23.30*	Revenues per sh	*27.00*
2.58	2.89	2.90	2.98	2.95	3.11	3.30	3.68	4.01	4.33	4.47	3.87	5.39	5.69	6.04	6.53	*6.85*	*7.35*	"Cash Flow" per sh	*9.00*
.93	1.26	1.32	1.42	1.52	1.60	1.92	2.18	2.35	2.51	2.59	2.34	2.96	3.14	3.34	3.58	*3.75*	*3.95*	Earnings per sh A	*4.75*
.42	.44	.46	.50	.54	.68	.80	1.04	1.20	1.45	1.56	1.74	1.98	2.08	2.21	2.36	*2.53*	*2.70*	Div'd Decl'd per sh B ■	*3.20*
2.85	3.40	4.17	5.28	4.86	3.50	3.41	3.60	3.09	3.04	3.26	4.01	4.51	6.21	6.71	7.17	*10.00*	*9.30*	Cap'l Spending per sh	*7.75*
10.65	11.46	12.35	13.25	14.27	15.26	16.26	17.20	18.05	18.73	19.60	27.42	28.29	29.98	31.02	32.06	*33.10*	*34.25*	Book Value per sh C	*38.25*
233.97	233.96	233.94	233.89	233.84	233.82	233.77	230.49	229.04	225.96	225.52	315.68	315.62	315.57	315.52	315.43	*315.50*	*315.50*	Common Shs Outst'g D	*315.50*
17.5	14.5	16.0	16.5	14.8	13.3	14.0	14.2	15.8	16.5	17.7	21.3	19.9	20.0	19.6	23.5	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.92	.77	.86	.88	.89	.89	.89	.89	1.01	.93	.93	1.07	1.04	1.01	1.06	1.26	*Value Line*		Relative P/E Ratio	*1.05*
2.6%	2.4%	2.2%	2.1%	2.4%	3.2%	3.0%	3.3%	3.2%	3.5%	3.4%	3.5%	3.4%	3.3%	3.4%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $12716 mill. Due in 5 Yrs $3874.9 mill.
LT Debt $11195 mill. LT Interest $526.2 mill.
Incl. $12.1 mill. capitalized leases.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $6.8 mill.
Pension Assets-12/19 $3007.0 mill.
Oblig $3123.7 mill.
Pfd Stock $30.4 mill. Pfd Div'd $1.2 mill.
260,000 shs. 3.60%, $100 par, callable. $101;
44,498 shs. 6%, $100 par.
Common Stock 315,434,531 shs.

MARKET CAP: $29 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
4202.5	4486.4	4246.4	4519.0	4997.1	5926.1	7472.3	7648.5	7679.5	7523.1	*7000*	*7350*	Revenues ($mill)	*8500*
455.6	514.0	547.5	578.6	589.5	640.3	940.2	998.2	1060.5	1134.2	*1185*	*1260*	Net Profit ($mill)	*1520*
35.4%	33.9%	35.9%	36.9%	38.0%	40.4%	37.6%	37.2%	13.8%	9.9%	*16.5%*	*16.5%*	Income Tax Rate	*16.5%*
18.6%	16.8%	9.4%	4.5%	1.3%	4.5%	3.8%	1.6%	2.1%	1.8%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.6%	53.6%	51.7%	50.6%	48.5%	51.2%	50.5%	48.0%	50.4%	52.5%	*50.5%*	*53.0%*	Long-Term Debt Ratio	*51.5%*
49.0%	46.0%	48.0%	49.1%	51.2%	48.6%	49.3%	51.9%	49.4%	47.4%	*49.5%*	*47.0%*	Common Equity Ratio	*48.0%*
7764.5	8608.0	8619.3	8626.6	8636.5	17809	18118	18238	19813	21355	*21100*	*23050*	Total Capital ($mill)	*25100*
9601.5	10160	10572	10907	11258	19190	19916	21347	22001	23620	*25800*	*27675*	Net Plant ($mill)	*31700*
7.5%	7.5%	7.9%	8.1%	8.1%	4.5%	6.3%	6.6%	6.5%	6.5%	*7.0%*	*6.5%*	Return on Total Cap'l	*7.5%*
11.9%	12.9%	13.1%	13.6%	13.2%	7.4%	10.5%	10.5%	10.8%	11.2%	*11.5%*	*11.5%*	Return on Shr. Equity	*12.5%*
12.0%	12.9%	13.2%	13.6%	13.3%	7.4%	10.5%	10.5%	10.8%	11.2%	*11.5%*	*11.5%*	Return on Com Equity E	*12.5%*
7.0%	6.8%	6.5%	5.9%	5.3%	2.1%	3.5%	3.6%	3.7%	3.8%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
41%	47%	51%	57%	60%	71%	67%	66%	66%	66%	*67%*	*68%*	All Div'ds to Net Prof	*68%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-3.0	+2.5	-2.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Lg. C&I Revs. per KWH (¢)	7.13	7.05	7.25
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.7	+.6
Fixed Charge Cov. (%)	422	323	300

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	3.0%	3.5%	*2.0%*
"Cash Flow"	7.5%	7.5%	*6.5%*
Earnings	8.5%	6.0%	*6.0%*
Dividends	14.5%	9.5%	*6.5%*
Book Value	8.0%	10.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2304	1631	1657	2055	7648.5
2018	2286	1672	1643	2076	7679.5
2019	2377	1590	1608	1947	7523.1
2020	2109	*1491*	*1500*	*1900*	*7000*
2021	*2250*	*1600*	*1550*	*1950*	*7350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.12	.63	.68	.71	3.14
2018	1.23	.73	.74	.65	3.34
2019	1.33	.74	.74	.77	3.58
2020	1.43	.62	.90	.80	*3.75*
2021	*1.50*	*.75*	*.90*	*.80*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.495	.495	.495	.495	1.98
2017	.52	.52	.52	.52	2.08
2018	.5525	.5525	.5525	.5525	2.21
2019	.59	.59	.59	.59	2.36
2020	.6325	.6325			

BUSINESS: WEC Energy Group, Inc. (formerly Wisconsin Energy) is a holding company for utilities that provide electric, gas & steam service in WI & gas service in IL, MN, & MI. Customers: 1.6 mill. elec., 2.9 mill. gas. Acq'd Integrys Energy 6/15. Sold Point Beach nuclear plant in '07. Electric revenue breakdown: residential, 35%; small commercial & industrial, 32%; large commercial & industrial, 21%; other, 12%. Generating sources: coal, 36%; gas, 29%; renewables, 4%; purchased, 31%. Fuel costs: 36% of revenues. '19 reported deprec. rates: 2.3%-3.2%. Has 7,500 employees. Chairman: Gale E. Klappa. President & CEO: Kevin Fletcher. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wecenergygroup.com.

WEC Energy appears to be well positioned to deal with the effects of the weak economy. Wisconsin was one of the first states to allow utilities to defer for future recovery costs associated with the coronavirus, such as increased bad-debt expense. From March 24th (the start of the stay-at-home order in Wisconsin) and May 2nd, kilowatt-hour sales declined 7%. Management estimated that the kilowatt-hour sales decline resulting from the economic turmoil will reduce pretax margin by $70 million-$80 million. However, management believes it can make up for this by cutting costs. The company's capital projects are on track, too. Accordingly, WEC Energy is maintaining its 2020 earnings guidance at $3.71-$3.75 a share, and continues to project long-term annual profit and dividend growth of 5%-7%. We left our 2020 estimate unchanged at $3.75 a share. However . . .

We trimmed our 2021 earnings estimate by $0.05 a share, to $3.95. Although the economy will likely be in better shape next year, any growth will come off a lower base. Also, Michigan Gas changed its plan to file a rate case that would have seen new tariffs take effect at the start of the new year. Our revised estimate would produce an increase of 5%, at the low end of WEC Energy's yearly target.

The company is asking the Wisconsin commission for approval to build two liquefied natural gas facilities. The total cost would be $370 million. Construction is expected to begin in the summer of 2021, with completion planned for late 2023.

WEC Energy is increasing its investment in three nonregulated wind projects. It has agreed to pay $118 million to boost its stake from 80% to 90%, an additional 75 megawatts. The company's total investment in the three wind farms will exceed $1 billion. WEC Energy expects to earn a higher return on equity from these projects than it does in its regulated utility operations.

This high-quality stock has outperformed most utility issues this year. The price has risen 1%. The dividend yield is below the utility mean, and the stock's 3- to 5-year total return potential is unspectacular.

Paul E. Debbas, CFA *June 12, 2020*

(A) Diluted EPS. Excl. gains on discont. ops.: '04, 77¢; '11, 6¢; nonrecurring gain: '17, 65¢. '18 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '19: $20.80/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '15: 10.0%-10.3%; in IL in '15: 9.05%; in MN in '19: 9.7%; in MI in '16: 9.9%; earned on avg. com. eq., '19: 11.4%. Regulatory Climate: WI, Above Avg.; IL, Below Avg.; MN & MI, Avg.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	75
Earnings Predictability	90

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WESTAR ENERGY NYSE-WR

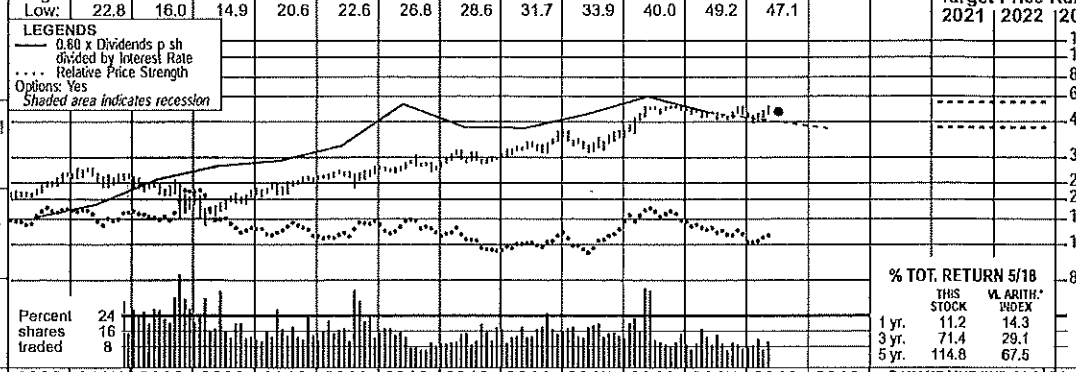
RECENT PRICE 54.00 | P/E RATIO 20.8 (Trailing: 23.8 Median: 16.0) | RELATIVE P/E RATIO 1.14 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS — Suspended 6/10/16
SAFETY 2 Raised 4/1/05
TECHNICAL — Suspended 6/10/16
BETA .65 (1.00 = Market)

High:	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0	57.5	57.3	57.4	
Low:	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9	40.0	49.2	47.1	

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	See Text		
Low			

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	16	8	0	0
to Sell	4	0	0	5	0	0	0	5	0

Institutional Decisions

	3Q2017	4Q2017	1Q2018
to Buy	164	141	150
to Sell	146	130	167
Hld's(000)	118474	107206	106985

% TOT. RETURN 5/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.2	14.3
3 yr.	71.4	29.1
5 yr.	114.8	67.5

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	17.40	18.07	18.09			Revenues per sh	
4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	4.26	4.83	4.90			"Cash Flow" per sh	
1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	2.09	2.43	2.27	See	See	Earnings per sh A	See
1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	1.44	1.52	1.60	Text	Text	Div'd Decl'd per sh B■†	Text
1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	4.95	7.67	5.38			Cap'l Spending per sh	
13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	25.87	26.84	27.50			Book Value per sh C	
71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	141.35	141.79	142.09			Common Shs Outst'g E	
14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	18.5	21.6	23.4			Avg Ann'l P/E Ratio	
.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	.93	1.13	1.15			Relative P/E Ratio	
8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%	3.7%	2.9%	3.0%			Avg Ann'l Div'd Yield	

CAPITAL STRUCTURE as of 3/31/18
Total Debt $3978.1 mill. Due in 5 Yrs $725 mill.
LT Debt $3688.3 mill. LT Interest $170.0 mill.
(LT interest earned: 3.8x)

Pension Assets 12/17 $719 mill. Oblig. $1.1 bill.

Pfd Stock None

Common Stock 142,233,103 shs.
MARKET CAP: $7.7 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	2459.2	2562.1	2571.0			Revenues ($mill)	
136.8	141.3	203.9	214.0	275.1	292.5	313.3	291.9	346.6	323.9			Net Profit ($mill)	
24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	33.5%	33.8%	31.0%			Income Tax Rate	
--	--	--	--	--	--	--	10.4%	10.4%	10.1%			AFUDC % to Net Profit	
49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	47.5%	47.9%	51.0%			Long-Term Debt Ratio	
49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	52.5%	52.1%	49.0%	See	See	Common Equity Ratio	See
4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	6958.8	7305.8	7595.7	Text	Text	Total Capital ($mill)	Text
5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	8793.1	9506.3	9553.8			Net Plant ($mill)	
4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	5.3%	5.7%	4.3%			Return on Total Cap'l	
6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	8.0%	9.1%	8.3%			Return on Shr. Equity	
6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	8.0%	9.1%	8.3%			Return on Com Equity D	
1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	2.9%	3.7%	2.4%			Retained to Com Eq	
80%	87%	63%	65%	57%	56%	55%	69%	63%	70%			All Div'ds to Net Prof	

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.5	+3.5	-1.3
Avg. Indust. Use (MWH)	5654	5761	5689
Avg. Indust. Revs. per KWH (¢)	6.68	6.77	6.71
Capacity at Peak (Mw)	7187	7523	7834
Peak Load, Summer (Mw)	5167	5184	5242
Annual Load Factor (%)	56.1	56.4	56.8
% Change Customers (yr-end)	+.2	+.3	+.6
Fixed Charge Cov. (%)	330	335	305

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	0.5%	1.0%	2.5%
"Cash Flow"	3.0%	3.0%	6.5%
Earnings	4.0%	7.0%	7.5%
Dividends	5.0%	3.0%	4.0%
Book Value	4.5%	4.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	590.8	589.6	732.8	546.0	2459.2
2016	569.5	621.4	764.7	606.5	2562.1
2017	572.6	609.3	794.3	594.8	2571.0
2018	600.2	See Text			
2019					

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.38	.46	.97	.28	2.09
2016	.46	.51	1.08	.38	2.43
2017	.42	.50	1.11	.24	2.27
2018	.42	See Text			
2019					

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.34	.35	.35	.35	1.39
2015	.35	.36	.36	.36	1.43
2016	.38	.38	.38	.38	1.52
2017	.40	.40	.40	.40	1.60
2018	.40	.40			

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 708,000 customers mostly in Kansas. 2017 Electric revenue sources: residential and rural, 32%; commercial and business, 28%; industrial, 16%; other, 24%. The company sold its investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2017 depreciation rate: 2.5%. Estimated plant age: 17 years. Fuels: coal, 41%; nuclear, 7%; gas, 30%; renewable, 22%. Has 2,205 employees. Chief Executive Officer and President: Mark A. Ruelle. Chairman: Charles Q. Chandler. Incorporated: Kansas. Address: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

The proposed merger of equals between Westar Energy and Great Plains Energy has finally closed. Under the agreement, no premium was paid and no cash was exchanged with respect to either entity. A holding company (named Evergy) was created in which Westar stockholders received one share for each of their individual shares, and Great Plains stockholders received 0.5981 shares for each share that they owned. The merger created a utility with a combined equity value of about $15 billion, with roughly one million customers in Kansas and 600,000 in Missouri. The transaction was completed in June and Evergy began trading on the NYSE shortly thereafter.

The combination of the adjacent utilities should offer opportunities for cost efficiencies. The companies are targeting average annual earnings and dividend growth of 6%-8%, with a targeted payout ratio of 60%-70%. The utilities also expect to save $550 million in the first five years upon completion of the deal, and $140 million to $170 million annually thereafter.

The combined entity expects to set its initial dividend at a level that maintains the current payout for Great Plains stockholders. This would result in an increase of about 15% for Westar stockholders.

Evergy is expected to maintain a strong balance sheet and solid investment-grade credit profile. The transaction involves no cash, so a heavy debt load will not be an issue. Additional updates on the company's capital structure will be provided on its next earnings call.

Rate cases are pending in Kansas. Westar has asked the Kansas Corporation Commission to approve a net $52.6 million (2.6%) tariff increase for it retail electric customers. The application was filed earlier this year, and a decision by the KCC is expected by September. If approved, the rate hikes would go into effect in February of 2019.

With the merger of equals now complete, this will be our final report on Westar Energy. It took almost two years for the companies to close this deal, but the combination has finally come to fruition.

Daniel Henigson, CFA *June 15, 2018*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next earnings report due early August.
(B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2017: $5.66/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '17: 10.0%; earned on avg. com. eq., '17: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	85

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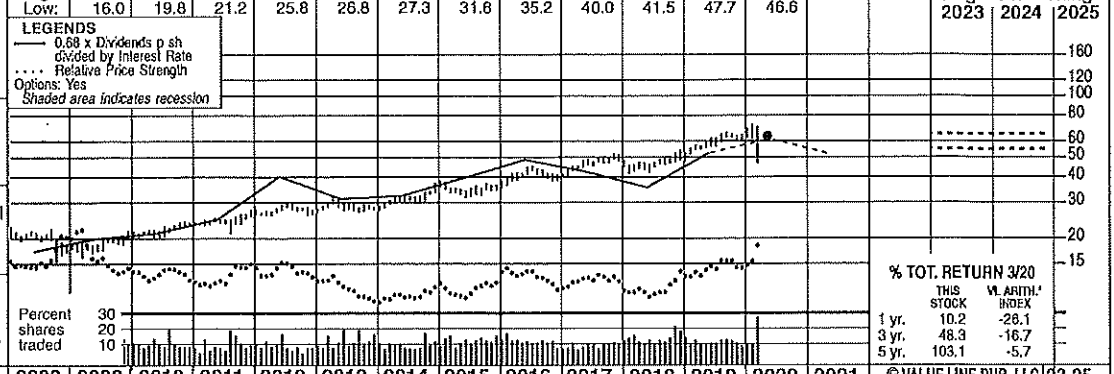
XCEL ENERGY NDQ-XEL

RECENT PRICE 63.66 | P/E RATIO 22.7 (Trailing: 24.1 Median: 16.0) | RELATIVE P/E RATIO 1.55 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 3 Lowered 9/20/19
SAFETY 1 Raised 5/1/15
TECHNICAL 1 Raised 4/24/20
BETA .45 (1.00 = Market)

High:	21.9	24.4	27.8	29.9	31.8	37.6	38.3	45.4	52.2	54.1	66.1	72.1
Low:	16.0	19.8	21.2	25.8	26.8	27.3	31.6	35.2	40.0	41.5	47.7	46.6

LEGENDS
— 0.68 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$54-$79 $67 (5%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(Nil)	4%
Low	55	(-15%)	Nil

Institutional Decisions

	2Q2019	3Q2019	4Q2019
to Buy	352	347	395
to Sell	308	333	320
Hld's(000)	404643	407757	409339

Percent shares traded 30 20 10

% TOT. RETURN 3/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.2	-26.1
3 yr.	48.3	-16.7
5 yr.	103.1	-5.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	21.98	*22.25*	*23.05*	Revenues per sh	*25.50*
3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	*6.50*	*7.00*	"Cash Flow" per sh	*8.75*
1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.64	*2.75*	*2.90*	Earnings per sh A	*3.50*
.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	*1.72*	*1.82*	Div'd Decl'd per sh B ■	*2.15*
3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	8.05	*6.70*	*7.05*	Cap'l Spending per sh	*8.50*
12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	25.24	*27.20*	*28.45*	Book Value per sh C	*32.75*
400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	524.54	*539.00*	*542.00*	Common Shs Outst'g D	*548.00*
13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	22.3	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.21	*Value Line*		Relative P/E Ratio	*.95*
4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 12/31/19
Total Debt $18704 mill. Due in 5 Yrs $3820 mill.
LT Debt $17407 mill. LT Interest $731 mill.
Incl. $77 mill. capitalized leases.
(LT interest earned: 3.0x)

Leases, Uncapitalized Annual rentals $262 mill.
Pension Assets-12/19 $3184 mill.
Oblig $3701 mill.

Pfd Stock None

Common Stock 524,669,024 shs.
as of 2/13/20
MARKET CAP: $33 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
10311	10655	10128	10915	11686	11024	11107	11404	11537	11529	*12000*	*12500*	Revenues ($mill)	*14000*
727.0	841.4	905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	*1440*	*1565*	Net Profit ($mill)	*1955*
37.5%	35.8%	33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	*Nil*	*Nil*	Income Tax Rate	*Nil*
11.7%	9.4%	10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
53.1%	51.1%	53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	*57.0%*	*57.0%*	Long-Term Debt Ratio	*57.0%*
46.3%	48.9%	46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	*43.0%*	*43.0%*	Common Equity Ratio	*43.0%*
17452	17331	19018	20477	21714	23092	25216	25975	28025	30646	*34050*	*35825*	Total Capital ($mill)	*41800*
20663	22353	23809	26122	28757	31206	32842	34329	36944	39483	*41025*	*42600*	Net Plant ($mill)	*48300*
5.7%	6.5%	6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	*10.0%*	*10.0%*	Return on Shr. Equity	*11.0%*
8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	*10.0%*	*10.0%*	Return on Com Equity E	*11.0%*
3.6%	4.3%	4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	*3.5%*	*4.0%*	Retained to Com Eq	*4.5%*
59%	56%	54%	54%	55%	57%	61%	62%	58%	58%	*64%*	*63%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-.7	+3.2	-1.2
Large C & I Use (MWH)	22642	23004	NA
Large C & I Revs. per KWH (¢)	6.36	5.91	5.96
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	19591	20293	20146
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+1.1	+1.0
Fixed Charge Cov. (%)	330	281	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-.5%	.5%	*2.5%*
"Cash Flow"	5.5%	7.5%	*7.0%*
Earnings	5.5%	5.0%	*6.0%*
Dividends	5.0%	6.5%	*6.0%*
Book Value	4.5%	4.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2946	2645	3017	2796	11404
2018	2951	2658	3048	2880	11537
2019	3141	2577	3013	2798	11529
2020	*3250*	*2700*	*3150*	*2900*	*12000*
2021	*3350*	*2850*	*3300*	*3000*	*12500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.47	.45	.97	.42	2.30
2018	.57	.52	.96	.42	2.47
2019	.61	.46	1.01	.56	2.64
2020	*.63*	*.52*	*1.10*	*.50*	*2.75*
2021	*.67*	*.55*	*1.15*	*.53*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.32	.34	.34	.34	1.34
2017	.34	.36	.36	.36	1.42
2018	.36	.38	.38	.38	1.50
2019	.38	.405	.405	.405	1.60
2020	.405	.43			

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; P.S. of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.7 mill. elec., 2.1 mill. gas. Elec. rev. breakdown: res'l, 31%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 18%; other, 15%. Generating sources not avail. Fuel costs: 39% of revs. '19 reported depr. rate: 3.3%. Has 11,300 empls. Chairman & CEO: Ben Fowke. President & COO: Bob Frenzel. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy's utility in Colorado received an electric rate order. In February, the state commission granted Public Service of Colorado a rate hike of $35 million, based on a return on equity of 9.3% and a common-equity ratio of 55.6%. New tariffs took effect in February. The utility had sought an increase of $108 million, and asked the regulators for reconsideration.

P.S. of Colorado filed a gas rate application. The company requested an increase of $127 million, based on an ROE of 9.95% and a common-equity ratio of 55.8%. New rates are expected to take effect in the fourth quarter.

Southwestern Public Service reached a settlement of its rate case in New Mexico and is trying to do so in Texas, as well. The agreement in New Mexico, if approved by the state commission, will raise rates by $31 million, based on an ROE of 9.45% and a common-equity ratio of 54.8%. A ruling is expected in the second or third quarter. In Texas, the utility requested a hike of $136.5 million, based on an ROE of 10.35% and a common-equity ratio of 54.7%. New tariffs are expected to take effect in the third quarter. SPS plans to file rate cases in each state in early 2021 in order to recover the costs of wind projects that are scheduled for completion in late 2020.

Rate relief should help boost earnings in 2020 and 2021. We are sticking with our 2020 share-net estimate of $2.75, which is near the low end of Xcel's guidance of $2.73-$2.83. Any decline in kilowatt-hour sales will affect 55% of the company's electric business, as this portion lacks regulatory mecbanisms that decouple revenues and volume.

Xcel has agreed to sell a nonutility gas-fired plant. The buyer has agreed to pay $680 million for the facility. Xcel will use the proceeds for debt reduction. The asset sale is expected to be completed in the third quarter and will have little effect on the company's earnings.

This stock is priced expensively. Unlike most utility issues, the price is virtually unchanged in 2020. The dividend yield is below average, and total return potential does not stand out for the 18-month or 2023-2025 period.

Paul E. Debbas, CFA *April 24, 2020*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (losses) on discontinued ops.: '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '17 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '19: $5.60/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.6%; earned on avg. com. eq., '19: 10.8%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

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July 24, 2020

Aluminum Glut Revives Crisis-Era Storage Trade

by Joe Wallace – WSJ – Jun. 13, 2020

Wall Street banks and investors are joining commodity traders in **stockpiling aluminum**, an unconventional way to make money at a time when returns on bonds are historically low.

The coronavirus pandemic hit the aluminum market hard by triggering a downturn in the auto and aerospace industries, two big buyers. A surfeit pushed benchmark **aluminum prices down 12% this year**, to **$1,582 a metric ton** on the **London Metal Exchange**.

It also revived interest in **hoarding aluminum** to **sell at a later date**, a trade that became **controversial after** the **2008-09 financial crisis**.

"This is a really telling signal that we're in a **really massive surplus,"** said Oliver Nugent, a commodities strategist at Citigroup Inc. "There's money on the table because the market is paying people to clear markets of this glut."

At current prices, **traders can earn an annualized return** of **about 2%** from **stashing aluminum in** a **warehouse**, Mr. Nugent calculated. The trade is particularly popular in Europe and Asia, but less widespread in the U.S. because of tariffs on aluminum imports that aren't from certain countries, he said.

It works like this: With metal readily available, the **price** of **buying aluminum** has **fallen below** the **cost** of **paying for** the **material now** and **taking delivery later**.

That means traders can buy aluminum on the cheap, typically using borrowed money, and lock in a higher price for selling the metal on the LME through later-dated contracts. If the discount for purchasing aluminum exceeds a trader's borrowing costs and the expense of keeping the metal in a warehouse, a profit can be made. To maximize earnings, financiers often truck the aluminum to a warehouse that charges cheaper rent.

Traders draw parallels with the recent crash in energy markets, when the collapse in demand caused by the pandemic dragged down spot oil prices. Commodity houses including U.K.-listed Glencore PLC and Switzerland-based Vitol Group cashed in by pouring crude into storage and waiting to sell it to buyers at a higher price when demand recovered.

For financial institutions, the physical **aluminum** market can be more accessible than oil. The metal **isn't flammable** and warehouse space is relatively easy to come by. Aluminum **can be kept outside** because it **doesn't rust**.

Sitting on aluminum isn't the same money-spinner that it was in **2008-09**, when the **gap between spot prices** and **futures** was **wider than** it is **now**.

In the **current market**, a company with low funding costs could make around **$30 a metric ton each year storing aluminum**, according to a U.S.based metals trader. That equates to an **annual profit of $3 million for storing 100,000 tons of metal**.

JPMorgan Chase & Co. and **Citigroup** are particularly active in the aluminum-storage trade, according to market participants. Both banks declined to comment.

There is another incentive for banks to stockpile aluminum. Doing so enables them to hedge large positions they have from selling long-term metal forwards to clients such as auto makers.

Wall Street also got involved in aluminum storage after the last financial crisis. That prompted complaints by beer and soda companies that banks were artificially pushing up prices for end consumers, as the material is used in food-and drink packaging. A key difference now is that lenders aren't major owners of metal warehouses, following investigations by U.S. regulators.

But buying aluminum to stockpile comes at a price, and profits aren't guaranteed.

Purchasing enough to make the play worthwhile is expensive: on top of the LME price, traders pay a premium that varies with the quality and where in the world they buy it. Getting out of the position can be tricky, and warehouse fraud poses a danger.

–

CBO Downgrades Economic Forecast

by Kate Davidson – WSJ – Jul. 3, 2020

Unemployment is likely to remain in double digits through yearend, and the **economic downturn will be more severe than previously forecast**, according to projections released Thursday by the **Congressional Budget Office**. The **CBO** estimates the **jobless rate** will end the year at 10.5%, lower than its earlier forecast of 11.5%. Nevertheless, it is **likely** to **remain above** the **pre-coronavirus pandemic level** of about **3.5% through** the **end** of the decade. Gross domestic product, the broadest measure of economic output, is expected to grow rapidly in the second half of 2020 as social-distancing measures are lifted and trillions of dollars in stimulus spending takes effect.

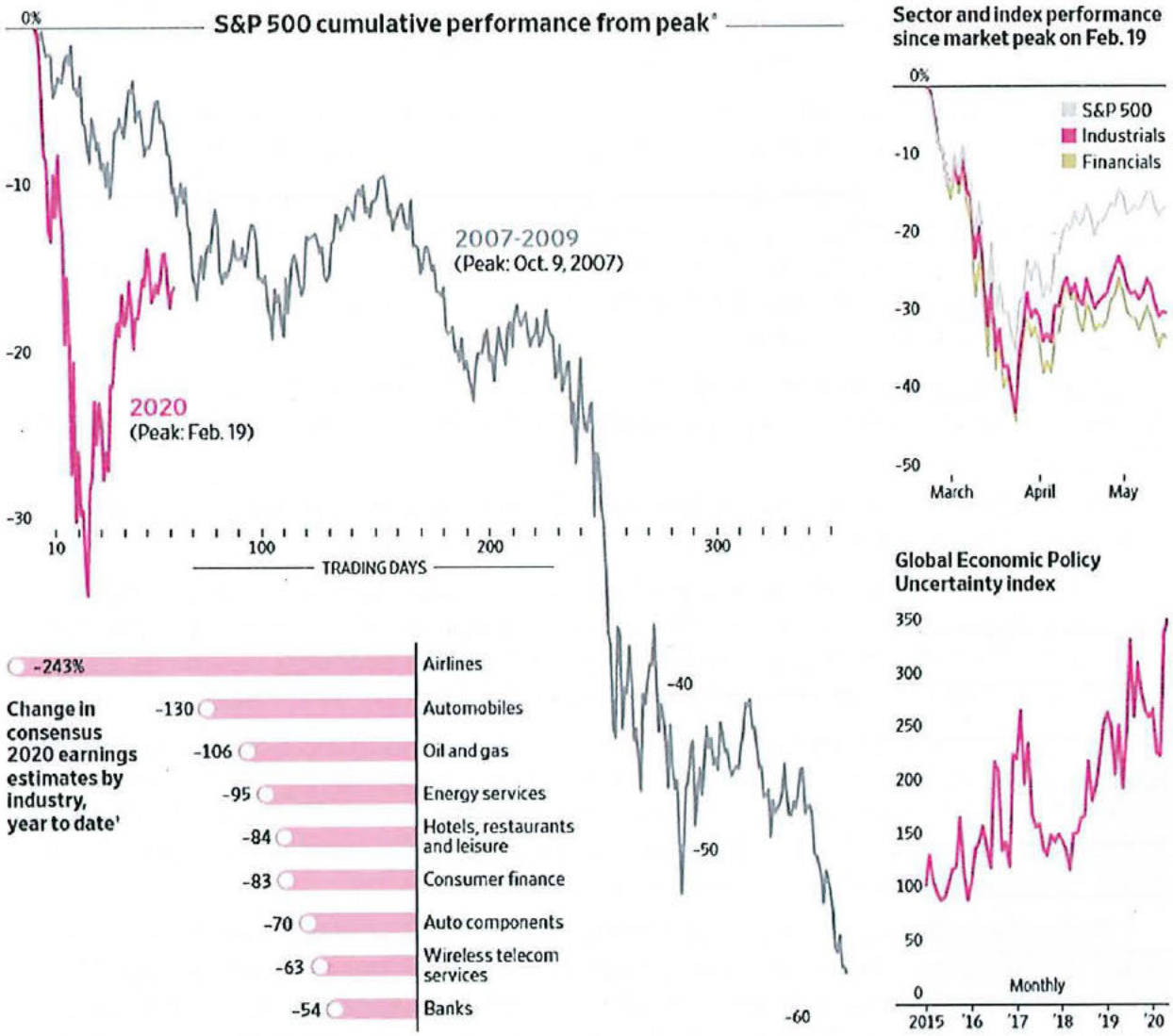
But that won't be enough to overcome the impact of widespread business closures earlier in the year.

Output in the **fourth quarter of 2020** will be **5.9% lower than** a **year earlier**, the agency said, worse than the 5.6% drop it projected in May. "The economic outlook for 2020 to 2030 has deteriorated significantly since the agency last published its full baseline economic projections in January," CBO director Phillip Swagel said in Thursday's report.

Bets on Slow Recovery Challenge Stocks

by Amrith Ramkumar – WSJ – May 18, 2020

Investors increasingly believe fallout from virus will last longer than they first thought.



*Continues until S&P 500 hit its low point in 2009 †As of May 11

Sources: Dow Jones Market Data (S&P 500 cumulative performance), Goldman Sachs (earnings estimates) via FactSet (sector and index performance); Economic Policy Uncertainty (index)

Stocks recorded their **biggest weekly percentage drop** in **nearly two months last week**, a **sign** that recent gains are just one step of what many **analysts say** will be a **long** and **painful recovery**.

While many investors remain hopeful that stimulus measures from central banks and governments will ease pressure on the world economy, there is a growing belief that the fallout from the **coronavirus pandemic will last longer than anticipated**.

Fueling the caution: the prospect that lockdowns could linger or stimulus measures could prove insufficient to keep pace with job losses and business closures.

The S&P 500 fell 2.3% last week, recording its biggest weekly drop since the extreme volatility of mid-March. **Stocks** have **bounced 28% above** their **multiyear lows** from that month **but remain 15% below** their **February records**.

Many investors caution against reading too much into the moves at this point. Markets are only a few months into what could be a lengthy crisis punctuated by the **sharpest U.S. economic contraction since** the **Great Depression**.

"This is going to be a bit of a marathon for the economy to look like it did pre-crisis," said Mona Mahajan, U.S. investment strategist at Allianz Global Investors.

During the financial crisis, stocks went through several ups and downs between peaking in October 2007 and hitting a low point in March 2009. They shook off early signs of the burgeoning mortgage crisis only to tumble a few months later, posting swings that included a 24% rise through the end of 2008. Stocks then collapsed again before bottoming in March 2009.

Many analysts say the speed of this year's market moves and economic crash make the coronavirus crisis unique, adding to the challenge of forecasting where stocks will go next.

"A lot of information still has to flow through the markets," said Nela Richardson, an investment strategist at Edward Jones. "It's going to be bumpy."

Investors this week will monitor weekly jobless claims data for the latest gauge of U.S. unemployment, as well as IHS Markit purchasing managers indexes that assess activity in the services and manufacturing segments of the economy. Earnings from retailers including Walmart Inc. and Home Depot Inc. will also be in focus.

Shares of economically sensitive companies were among the worst performers last week, with the S& P 500 industrial and financial sectors each falling 5.7% or more. Shares of Bank of America Corp. slid 9%, while manufacturer Deere & Co. declined 8%. Companies more tied to the health of the economy have struggled lately with millions of people practicing social distancing and unemployment soaring.

Their recent declines came after Anthony Fauci, director of the National Institute of Allergy and Infectious Diseases, warned against reopening the economy too quickly. Federal Reserve Chairman Jerome Powell also called the economic outlook "highly uncertain" and said more congressional stimulus might be needed to support growth.

The House of Representatives narrowly passed a roughly $3 trillion spending bill late Friday, but Republican leaders have said the legislation has no prospect of advancing in the GOP-led Senate.

Investors are waiting to see whether the fast-growing technology companies that have powered the recent market rebound can continue supporting major indexes. Because of **ultralow interest rates around** the **world**, some say there is little alternative to holding large tech companies that can still grow sales, even with

consumers stuck at home. But some analysts caution that even companies like Apple Inc. or Microsoft Corp. will be hurt by a longer economic malaise.

Firms across industries have been forced to curtail spending and rein in forward-looking profit targets, highlighting the potential long-term threat facing stocks. On recent first-quarter earnings calls, 180 S& P 500 companies discussed withdrawing their financial projections, according to a Goldman Sachs Group analysis of transcripts through May 11.

"There's so many ifs out there that we just don't know what's going to happen," United Parcel Service Inc. Chief Executive David Abney said on the company's earnings call last month. UPS slashed spending and suspended share buybacks for the year to protect its finances, even as home deliveries by the shipping company surge. Shares fell 4% last week.

Earnings estimates for the full year have tumbled across sectors, but analysts say a range of possible outcomes are making such projections hard to interpret.

In April, an **index** of **global economic-policy uncertainty developed** by **professors** at **Northwestern** University, **Stanford** University **and** the **University** of **Chicago rose** to its **highest level on record** in data **going back to 1997**.

At the same time, some investors remain optimistic that stimulus measures will eventually support corporate profits, regardless of how long the crisis lasts. Those hopes will continue to be weighed against fresh data illustrating the economic damage. There's less and less folks who view the economic recovery as a V," Ms. Richardson said, referring to bets from earlier in the year on a speedy rebound in growth.

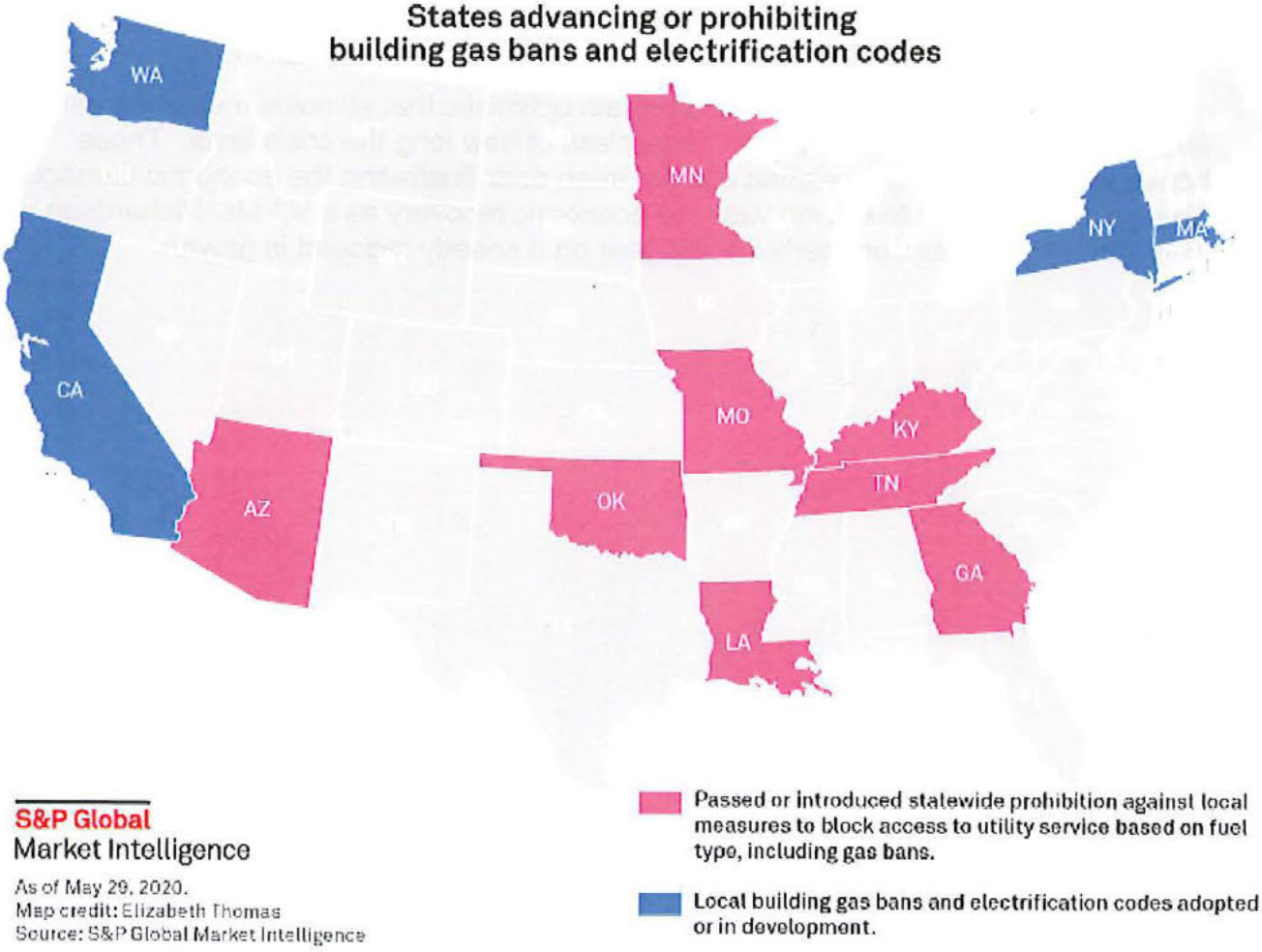
Report Identifies 20 Utilities Most At Risk From Rising Anti-Gas Sentiment

by Tom DiChristopher – S&P Global Market Intelligence – Jul. 13, 2020

Nearly one-third of large **gas utilities** are at risk of rising sentiment against natural gas, according to market research firm CreditSights.

Companies with **large service territories in coastal areas** are **most at risk, while many utilities** in the **interior U.S. remain** at **relatively low risk, CreditSights concluded** in a July 13 research note. The anti-gas sentiment is evident in recent **pipeline project cancellations**, **gas plant application denials** and **measures to require building electrification**, the report authors said.

"This ongoing debate is something investors should continue to be cognizant of, especially as state-level clean energy mandates continue to grow," CreditSights analysts Nick Moglia and Andrew DeVries wrote, although they stressed that their purpose was not to recommend securities.



The firm screened for gas utilities that had at least 100,000 residential customers at the end of 2019, turning up 58 pure-play local distribution companies and classifying 20 as at risk.

The at-risk list included National Grid PLC subsidiaries Brooklyn Union Gas Co., Boston Gas Co., KeySpan Gas East Corp. and Colonial Gas Co. The firm cited National Grid USA's 2019 dispute over gas planning with New York as a prime example of regulatory and political pushback on gas use. It also pointed to a recent rate case settlement that saw two of Avangrid Inc.'s New York utilities agree to net-zero growth in gas use as "a clear push to curb overall gas usage."

New York City Mayor Bill de Blasio set a goal of eliminating gas use in city buildings by 2030, following a push in several Boston area towns and cities to adopt building gas bans modeled after a pioneering Berkeley, Calif., ordinance.

CreditSights also counted NiSource Inc. subsidiaries Columbia Gas of Pennsylvania Inc. and Columbia Gas of Massachusetts, officially known as Bay State Gas Co., as at risk. **Eversource Energy**, which **agreed** to **buy Columbia Gas** of **Massachusetts in February**, has two current subsidiaries on CreditSights' list: NSTAR Gas Co. and Yankee Gas Services Co.

Also in Pennsylvania, CreditSights sees municipal utility Philadelphia Gas Works Co. and UGI Corp.'s UGI Penn Natural Gas Inc. as at risk. Building electrification backers regularly float Philadelphia Gas Works as a candidate for distribution system retirement, but UGI executives recently said they see no signs that building electrification requirements will catch on in the Keystone State, a major shale gas producer.

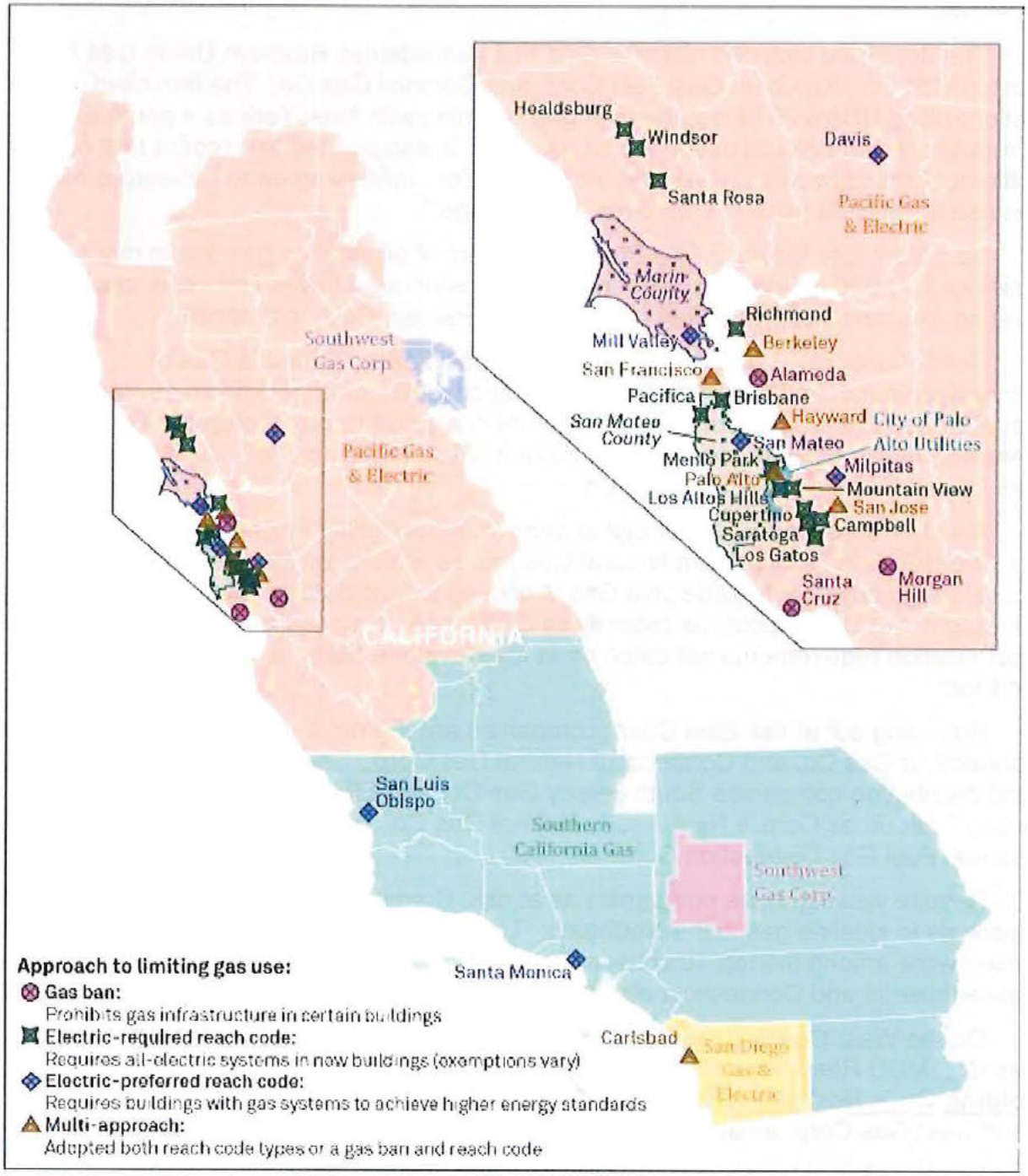
Rounding out at-risk East Coast companies are Iberdrola SA subsidiaries Southern Connecticut Gas Co. and Connecticut Natural Gas Corp., South Jersey Industries Inc.'s local distribution companies South Jersey Gas Co. and Elizabethtown Gas Co., New Jersey Resources Corp.'s New Jersey Natural Gas Co., and National Fuel Gas Co.'s National Fuel Gas Distribution Corp.

Despite viewing these companies as at risk, CreditSights questioned the viability of proposals to sideline gas in the Northeast. The analysts noted that New York and New Jersey were among the top 10 consumers of residential gas in 2018, while Massachusetts and Connecticut also ranked relatively high on the list.

On the West Coast, **CreditSights included** Sempra Energy's Southern California Gas Co., MDU Resources Group Inc.'s Cascade Natural Gas Corp., **Northwest Natural Holding Co.'s Northwest Natural Gas Co.**, and Southwest Gas Holdings Inc.'s Southwest Gas Corp. as at risk.

Notably absent from the list was PG&E Corp., which serves parts of the Bay Area, the epicenter of the movement to retire gas use in buildings. PG&E Corp. has expressed support for building electrification at the local and state level.

Building gas bans and all-electric reach codes passed in California
Natural gas utility service areas as defined by California Energy Commission



Data as of April 3, 2020.
Map credit: Elizabeth Thomas and Jose Miguel Fidel C. Javier
Sources: Building Decarbonization Coalition; Sierra Club; California Energy Commission

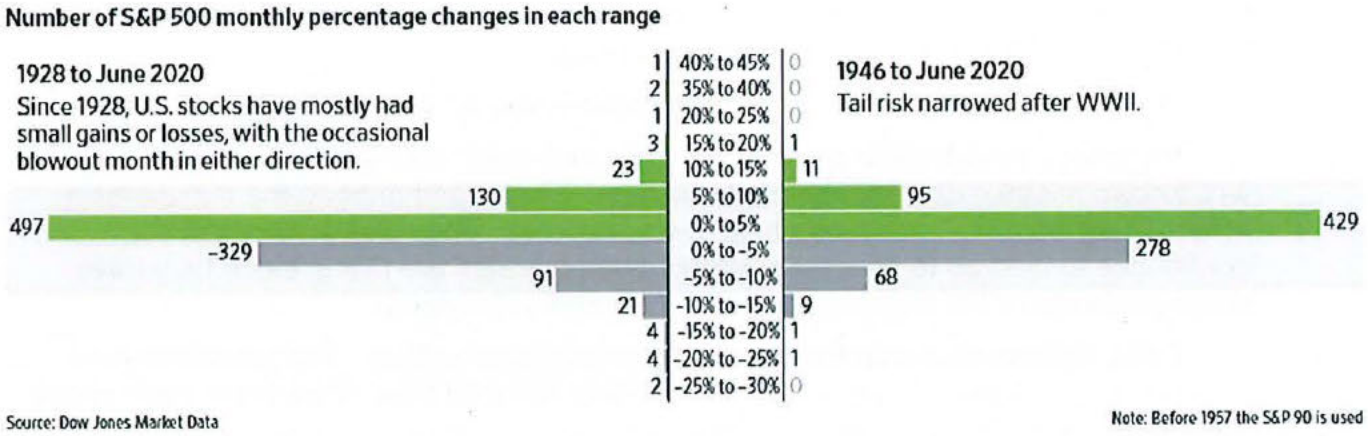
S&P Global
Market Intelligence

Investors Have Deep Fear of Missing Out

by James Mackintosh – WSJ Streetwise Column – Jun. 15, 2020

After the **financial crisis** there was a **rush** to **buy "tail risk" funds** designed to **protect against** a **crash** by providing outsize returns when markets fall. They **mostly worked well this year as** the spread of the **coronavirus hammered stock prices**.

But **now investors have** the **opposite problem**: They want to hold nice safe assets but have a **deep fear of missing out FOMO** – if the markets resume their rebound, interrupted this week. One solution: a FOMO fund.



So far as I can tell, there is only one FOMO fund and it is private with only one external institutional investor. It is run as a sideline to the main tail-risk business of California-based LongTail Alpha LLC, and, according to a letter shown to The Wall Street Journal by its investor, by the start of this month the fund gained 93.9% from when it put money in at the end of March.

The idea is to use options to gain heavier exposure to jumps in the market while limiting losses to the premium paid to own those options. That frees the investor to be more cautious with the rest of the portfolio – the exact opposite of the standard tail-risk fund.

Call options, which give the right but not the obligation to buy at a predetermined price in the future, are standard fare for investors making active decisions. But systematically using them to gain exposure to any rise in the markets has been a money-losing strategy in the past. Call options expire worthless if the market goes sideways or down. They make most money when the market suddenly jumps, which it has done in the past far less often than suddenly falling. Vineer Bhansali, chief investment officer at LongTail, said he couldn't discuss the fund itself because it is private. But he said times had changed. "**Melt-ups** are just as likely as meltdowns in this environment of central bank money printing," he said.

If the Federal Reserve gives you a free put option to protect against losses – because we know policy makers will step in and help if the market plunges – then it makes sense to sell a put, collecting the premium and profiting as long as the market doesn't fall more than a predefined amount. But **selling puts** is **far too dangerous** a **strategy for most**. It brings with it **potentially huge losses if markets crash before**

central banks get their **act** together, because the seller of a put has to buy stocks at the predefined price, even if the shares are trading much lower. A better way to make a similar bet on the Fed is to buy a call, where the potential loss is limited to the premium paid.

MR. Bhansali's fund just caught a **record melt-up** in the **S&P 500**, which **rose 39.6% in 50 days** (the S&P's narrower predecessor index rose even more in the false start of 1932). The twin questions for investors wanting to use options are whether we will see more melt-ups, and whether the market is mispricing the melt-up likelihood. If the answers are "yes" and "yes," a FOMO fund makes perfect sense. If we return to the norms of history, then the answers are "no" and "no," and it will bleed money for long periods when markets go sideways or rise slowly.

However, there is a deeper question about **investor psychology**.

Investors tend to **take profits too early** and **hold losing positions too long**, a well-known mistake documented by behavioral finance and dubbed the **disposition effect**. Traditional tail-risk funds help to counter that. They give an investor the confidence to hold on to their risky assets when markets are rising, since they have some protection if the worst happens and markets fall sharply.

CALL options also help to overcome the disposition effect: The predetermined expiration date makes it easy to let your winners run until then. One could cash in any gains early by selling the option, but the psychology of having committed up front helps to counter this. On top of that, the losses are defined as the entire premium, which allows an investor to run the rest of her portfolio in the knowledge of exactly what potential losses this upside bet brings. Unfortunately, the options market is complex and for most people too hard to trade directly.

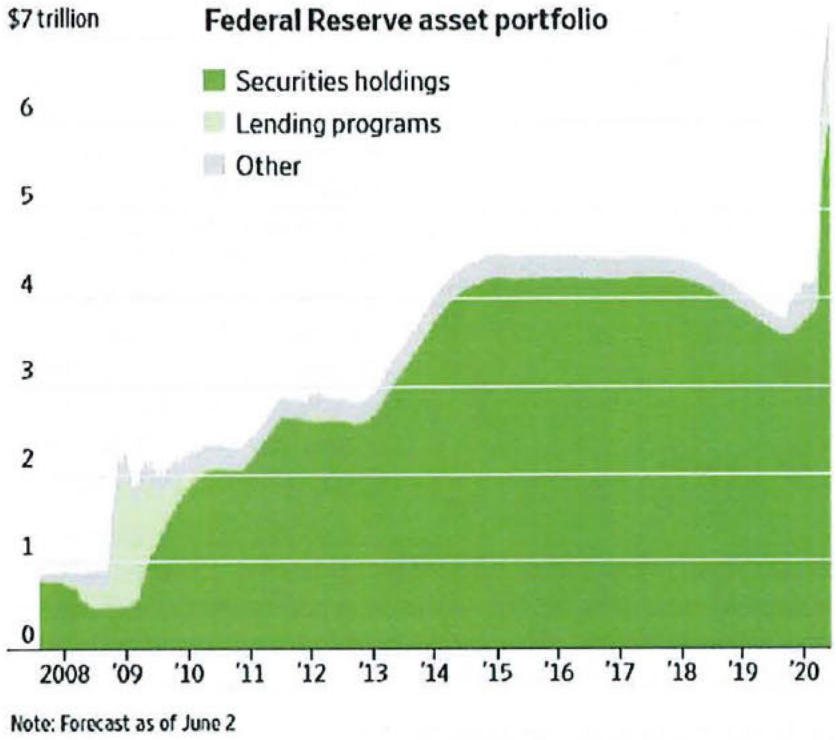
I recommended taking profits on the short bull market at the end of April, which in retrospect looks like it was too early. Maybe stocks can keep going up, propelled by continued easy money and a fast-recovering economy, albeit not in a straight line. But the risk that something goes wrong seems to me to be bigger than the market is acknowledging.

I'm happy to miss out on fleeting gains. But a FOMO fund would let me access any return to upward momentum for a defined upfront cost. That is better than feeling pressured to put an entire portfolio at risk.

Fed Looks to Put Cap on Treasury Yields

by Caitlin Ostroff and Sebastian
Paul J. Davies contributed to this article.

Investors are preparing for the **Fed**eral Reserve to tap a **policy tool untouched since** the **aftermath** of **World War II**, a move that **could change how key financial markets behave** and give an even bigger boost to the stock market's best performers.



Members of the Fed are embracing the idea of putting **caps on government bond yields**. The **Fed** would **buy Treasurys** in **whatever amount necessary** to **keep borrowing costs from getting above** a **specific range** or **maximum yield**. It last introduced yield caps during the **1940s**, when the Treasury needed help **financing war expenditures**, **exiting** them in **1951**.

The **Fed** has offered trillions of dollars to quell the economic shock of the coronavirus shutdown. The caps would be a way to make sure those efforts aren't undermined by rising yields. On Wednesday, **Chair**man Jerome **Powell said** central bank officials reviewed whether interest-rate caps would complement current monetary policy tools, adding that it **remains** an "**open question**."

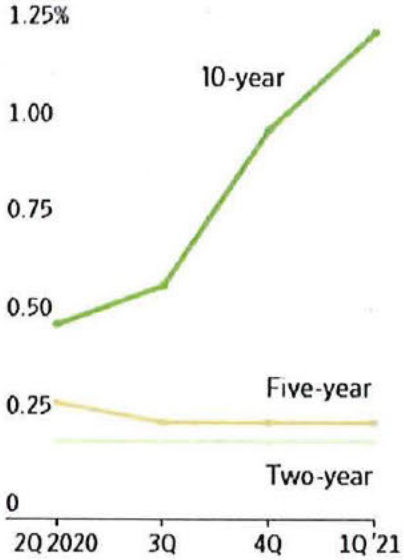
Such a move raises worries that in suppressing medium-term yields, the market loses an important benchmark against which much of the investment universe is measured. Such caps are also known as **yield-curve control** since the central bank **takes control from** the **market** in **determining both short-term and longer-term bond yields**.

"We are in the same situation as we were in the 1940s, minus the war," says Peter Garnry, head of equity strategy at Saxo Bank, noting the government is issuing large quantities of bonds it will have to pay back to buyers. "The only way you can get out of this debt mountain is **creating growth and inflation** at the same time. The yield-curve control is the necessary evil to do that."

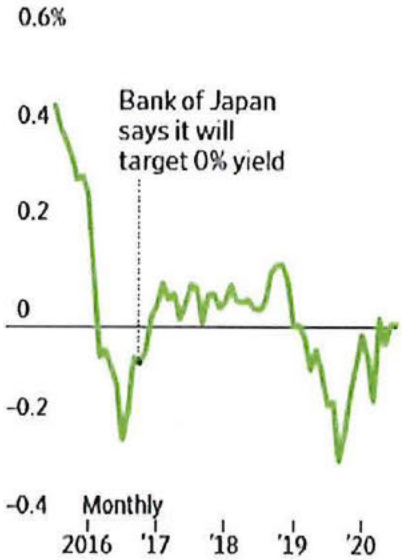
Analysts at **Bank of America** and **Goldman Sachs**, among others, now **both expect yield-curve control policies** in the **near future**. Many suspect that if the

central bank does employ controls, yields would be capped on either the two-year, three-year or five-year Treasury bonds.

Bank of America's U.S. rates forecasts with yield-curve control expectations



Yield on Japan's 10-year government bond



The Fed might use the policy to **avoid** repeating the so-called "**taper tantrum**" in **2013**, when **borrowing costs spiked after** the **Fed indicated** it **would gradually wind down** its bond-buying program. That reaction took something out of the already tepid postcrisis recovery, said Gennadiy Goldberg, U.S. rates strategist at TD Securities. He expects the Fed could announce controls in the second half of the year.

If the Fed implements yield-curve control, it would join two the ranks of two other central banks. Since 2016, the Bank of Japan has targeted a yield near 0% for the 10-year government bond, while short-term bond yields were in negative territory. The move marked another step in the country's effort to spur economic growth and inflation, which has still remained elusive.

More recently, the Reserve Bank of Australia in March said it would target a yield of 0.25% on its three-year bond to help support the country's economy. Fed officials have expressed interest in a similar policy calibration, as opposed to Japan's approach of targeting longer- dated bond yields.

In theory, capped yields, combined with a rebound in growth and inflation, would make it unattractive to own bonds. But the **Fed** has been **attempting** to **generate inflation** with **various tools** for **over** a **decade without** much effect.

So far, bond yields haven't shown a strong reaction to the prospect, since investors don't know yet exactly where the caps will be placed.

Yet some bond investors have sought to get ahead of any announcement. James Athey, senior investment manager at Aberdeen Standard Investments, purchased Treasury bonds that mature between two and 10 years in recent months, expecting yields to fall further amid weak near-term economic growth prospects and the potential for yield curve control. "Nobody's going to be pricing hawkish monetary policy," he said.

Others are holding off on buying Treasurys, expecting the Fed won't actually implement yield curve control in part because it could be a difficult policy to exit.

Skeptics of yield curve control contend that artificially holding down yields removes a key function of bond markets: Investors demand higher yields when they think prices

will rise in the future, since those price rises will erode the value of the bond. That makes them a measure of investor expectations of growth and inflation.

Some investors fear the Fed turning off that mechanism could distort prices in debt and derivatives markets, as well as the stock market, which take their cue from Treasurys.

"You're really losing information about where the market is going to be, and you're losing information for investors," said Robert Tipp, chief investment strategist for PGIM Fixed Income. He doesn't see yield-curve control as likely, with Fed members instead emphasizing to investors that they will not raise interest rates in the near future. **Capped yields** are **likely** to benefit "growth" stocks that have powered the market higher such as tech giants like **Facebook, Amazon** and **Netflix**, said Saxo's Mr. Garnry. **Low yields** tend to signal that growth is slow and so investors pay a premium for shares in companies that can grow quickly despite economic headwinds. **In discounted cash-flow models widely used by investors to value stocks, future earnings are worth more when rates are low**.

Beaten-down "value" stocks, which trade at a low multiple of their net worth, could **suffer**, especially if caps on medium-term yields also pulls down longer-term yields. **Value stocks** have shown a **strong relationship with Treasury yields** in recent years. When long-term yields rise faster than shorter-term yields, known in financial speak as a steeper yield curve, value stocks have rallied.

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CBO Sees Recovery Going Through 2021

by Paul Kiernan – WSJ – May 20, 2020

The **Congressional Budget Office said** the economy's recovery from the **downturn** related to **coronavirus responses will drag on through** the **end** of **next year**, **as investment collapses** and the **labor market experiences** its **sharpest deterioration since** the **1930s**.

Gross domestic product will **likely** be **5.6% smaller** in the **fourth quarter** of **2020 than** a **year earlier**, the CBO said Tuesday, despite an expected pickup in economic activity in the coming months. Though the CBO raised its projection for GDP growth in the fourth quarter of 2021 to 4.2% from 2.8% in an April forecast, the outlook continued to depict a long road to recovery.

That owes to the suddenness and severity of the current downturn, as well as expectations that social-distancing measures will remain in place, to some degree, for at least another year. The **CBO estimated GDP will shrink 11.2%** in the **current quarter from** the **January-to-March period**.

Central Bank Finds No Bond Sellers

by Matt Wirz – WSJ – Jun. 4, 2020

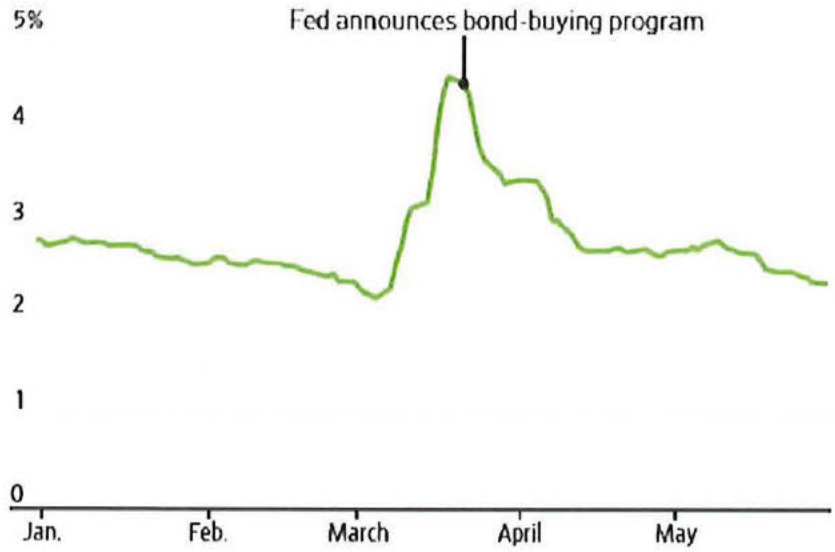
The **Federal Reserve** thawed credit markets in **March** by **promising** a **whatever-it-takes program** to **buy corporate bonds**. **Ten weeks later**, the **Fed** has **yet** to **buy** a **single bond**.

Just the **announcement of** the **backstop ended panic selling**, **boosted prices** and **fueled** a **record surge** of **new corporate-bond sales**. Companies are reluctant to sign up for Fed purchases because such a move could be seen as a sign of weakness during a market rebound, some bond fund managers and bank executives said.

"I really don't think the market needs it anymore," said Columbia Threadneedle Investments portfolio manager Thomas Murphy. "They are the victim of their own success."

The cost of borrowing for U.S. companies has returned to prepandemic levels.

Yield of Bloomberg Barclays U.S. Corporate Investment Grade Index



Source: FactSet

The Fed has yet to officially launch the initiative, which enables it to buy limited amounts of new and pre-existing bonds of companies, in part because it is hashing out the technical details. **Only companies** that **certify** they are **U.S.-based and haven't received other** aid **under** the **Cares Act** – a **$2 trillion financial- relief package** that includes loans and grants to businesses – **can participate in** the **program**, **which would disclose** their **names**, **amount** of their **bonds** that the **Fed would purchase** and **prices paid**.

Those terms "could give bond issuers pause, especially those that already have access to the markets," said Arvind Narayanan, co-head of investment- grade credit at Vanguard Group, which manages $1.8 trillion of fixed-income assets.

The Fed indirectly bolstered corporate- bond prices in May by purchasing $3 billion in shares of exchange-traded bond funds. But that is a fraction of the up to $750 billion earmarked for corporate-debt purchases.

The program should be "ready to go by the end of this month," Fed Chairman Jerome Powell said in Senate testimony in May. "I don't say that it won't be a day or

two into June, but that's our expectation." A spokeswoman for the Federal Reserve Bank of New York declined to comment beyond Mr. Powell's statement.

Fear of stigma isn't the only thing deterring participation. Some companies don't want the Fed buying their bonds now because that would limit how much the central bank could purchase if another wave of coronavirus roils markets, said one investment banker who covers large U.S. corporations. The **Fed can't use more than 1.5%** of its **backstop funds to lend directly to any single company**, according to disclosures by the New York Fed.

Still, the Fed needs to launch the program soon so that it can start making purchases quickly if markets seize up again, Mr. Narayanan said.

Some investors who bought investment-grade bonds in March and April with plans to sell them eventually to the Fed are growing weary of waiting, said Hans Mikkelsen, a bond strategist at Bank of America.

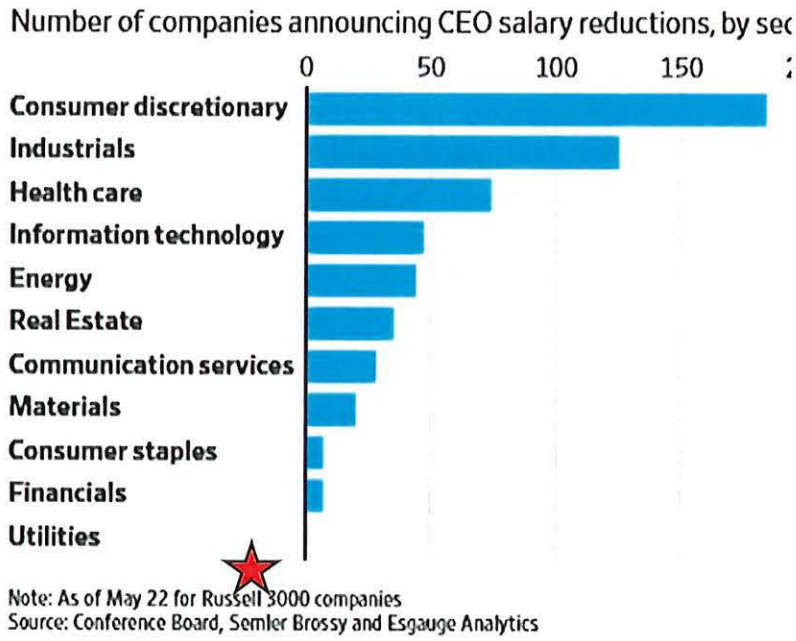
"There is a lot of uncertainty about what the Fed is going to do in the near term," he said.

An unusually large $500 million bundle of investment-grade bonds that traded last week was likely unloaded by one such "tourist" investor, Mr. Mikkelsen said. The portfolio included short-term bonds of such blue-chip companies as Caterpillar Inc. and International Business Machines Corp., which rallied steeply in April and have posted muted gains since.

CEO Salaries Decline, Stock Awards Remain

by Chip Cutter and Theo Francis – WSJ – Jun. 4, 2020

Hundreds of **U.S. companies reduced salaries** for their **chief executives** as the **coronavirus pandemic** swept across American business, a **reversal** for a group of leaders that until this year has **ridden** a **bull market** to **record compensation**.



Big-company **CEOs** had their **richest paydays ever** in **2019**, a Wall Street Journal analysis shows. But in March and April many took large cuts to their salaries after the deadly virus crippled global commerce. For 2020, **few** so far **changed** the **equity awards that make up** the **bulk** of **executive compensation** and the value of which is tied to the stock market.

Unlike prior years, now "the question is not how much of an increase are we giving over the normal salary; it's when do we even restore the old salaries," said Robin Ferracone, CEO of compensation consulting firm Farient Advisors LLC.

One reason corporate boards are slow to make bigger compensation changes: **uncertainty** over **how long** the **economic slowdown will last**, what its repercussions will be and how investors will react. **After plunging**, the **stock market** has **rebounded from** its **March lows**.

Median pay rose to $13**.1 million** in **2019** for the **chief executives** of **400 major companies** reporting compensation details through May, a Wall Street Journal analysis found. **Pay rose 8% or more for half** the **executives**, while **median investor returns reached 30%,** a **six-year high**.

That was last year. **This spring**, as the pandemic shut down operations, gutted revenues and sparked millions of layoffs, U.S. companies reduced CEO pay. Many airlines, hotels and retailers pulled financial forecasts and said they would need to revisit executive performance targets. **Nearly 600 companies** in the **Russell 3000 index cut pay for top executives** this **year, according to data compiled by the Conference Board, Semler Brossy and** Esgauge Analytics.

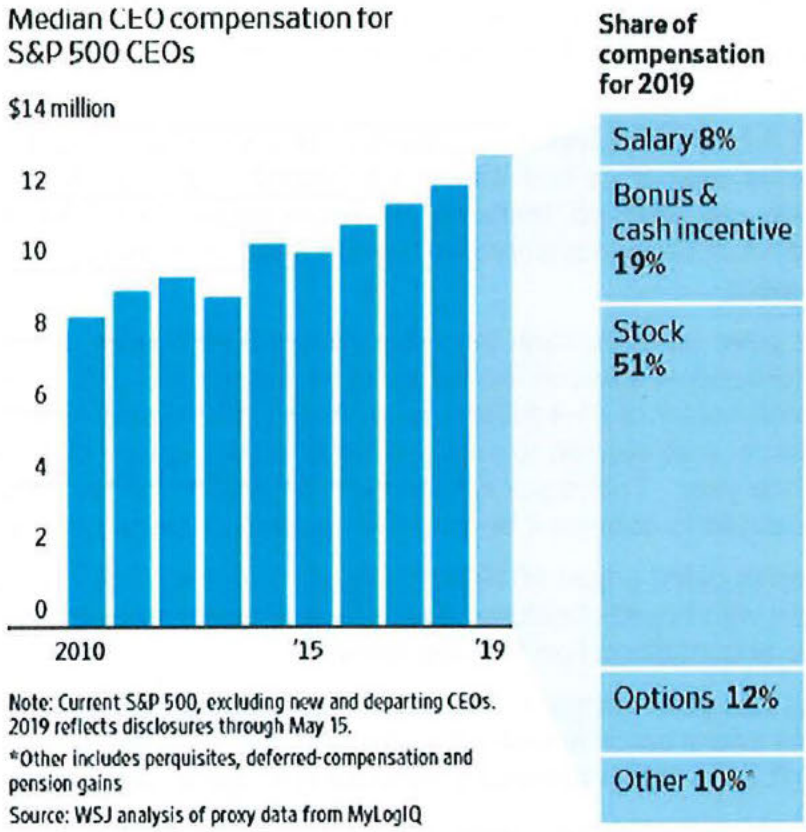
In the S& P 500, 102 companies reduced base salaries for top executives as of May 22, the study found. Those taking cuts include the CEOs of companies as varied as engine maker Cummins Inc., Walt Disney Co. and McDonald's Corp.

Of S&P 500 companies cutting pay, a **third suspended CEO salaries entirely**, while about **half reduced salary by 50% or less**, a separate analysis by the consulting firm Compensation Advisory Partners, or CAP, found.

Most companies said the **pay reductions** would stand **for several months**, and **many said** they would last **through year end**.

Base salaries have **typically** made up **8% to 10%** of **total pay** for **S&P 500 CEOs over** the **past decade**, the Journal analysis shows. Last year, half of S&P 500 CEOs received less than $1.2 million in salary. **Most cash compensation** comes **from annual bonuses**, and the **majority** of total compensation is received **via equity awards whose valuations fluctuate with** the **market**. In 2019, the median equity grant was valued at about $8.2 million, the Journal found.

Cuts to CEO salaries are largely symbolic, said Charles Elson, director of the Weinberg Center for Corporate Governance at the University of Delaware. "It's important to say that no one is escaping this thing," he said.



Note: Current S&P 500, excluding new and departing CEOs. 2019 reflects disclosures through May 15.
*Other includes perquisites, deferred-compensation and pension gains
Source: WSJ analysis of proxy data from MyLogIQ

CAP found that two-thirds of companies cutting CEO salaries did so while furloughing employees or cutting jobs or broader worker pay. **Sectors harder hit by** the **pandemic and accompanying economic shutdown** were **more likely** to **make CEO salary cuts**, the analysis found.

Companies and pay consultants often argue that sudden drops in pay – especially from external shocks rather than management decisions – risk demotivating CEOs or

may spur them to job hunt. And a few companies have moved to replace old equity awards with new ones.

Left: Bill Hornbuckle, acting chief executive of MGM Resorts International, elected to take restricted stock in place of his cash salary for the remainder of the year.

In mid-April, with its share price down by about half from Jan. 1, Sonic Automotive Inc. said it had canceled awards of performance-based restricted stock to more than 80 key employees.

In return, the executives at the operator of car dealerships received new stock options without performance hurdles that would begin to vest in 2021.

For example, CEO David Bruton Smith gave up nearly 97,000 restricted shares awarded on Feb. 12, when the stock closed at $32.09. Instead, on April 10, he received options on roughly 457,000 shares with the stock at $16.76. On Tuesday, the stock closed at $27.08.

Boards can't tell shareholders they believe in aligning pay and performance and "reap all the benefits when it's a bull market but then when it's a bear market, you turn around and actually say, well, no, that's not fair to executives," said Aaron Bertinetti, a senior vice president at proxy advisory firm Glass Lewis, who criticized Sonic's move. Sonic didn't comment.

Some CEOs gave up more cash than required by their boards. Casino operator MGM Resorts International lowered the salary of its acting CEO, Bill Hornbuckle, to $1.1 million from his prior salary of $1.4 million, as of April 1. Mr. Hornbuckle, who took on the role in late March, also elected to take restricted stock in place of his cash salary for the remainder of the year. That stock will vest and be paid in full on Dec. 31. An MGM spokeswoman declined to comment beyond the company's securities filings.

Most companies didn't adjust 2019 compensation as the pandemic struck, even though it coincided with boards finalizing bonuses and equity awards, said Ira Kay, managing partner at consulting firm Pay Governance.

As for setting this year's targets, "most companies are waiting, both to be consistent with the social environment right now, but also because they can't set goals because they don't know when the economy's going to open," Mr. Kay said.

Traditional metrics that shape executive compensation, including revenue growth, may make less sense in the new environment, consultants said. Boards may now need to structure pay plans for survival, rather than growth.

"Today, it's how you keep a business alive," said the Weinberg Center's Mr. Elson. "That's a big difference in how you design compensation and how you think about the business."

Anticipating that many boards may change short-term performance measures and goals, proxy advisory firm Institutional Shareholder Services said in April it expected explanations from companies for any such changes.

ISS also reiterated that its policies generally frown upon changes to existing long-term compensation plans already in progress over multiyear periods.

A fuller picture of pay changes in the pandemic will emerge over the coming year, as companies decide how to grant stock or option awards. Still, executives taking a hit to their cash salaries now represents a shift from prior economic downturns, said Irv Becker, vice chairman at executive- search and organizational consulting firm Korn Ferry.

"Just the simple fact that executives came out early and said, 'We're taking the biggest hits, and we're taking the hits first,' even though it may be symbolic and even though it just may be base salary, that's a change."

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Cleco Announces Long-Term Payment Plan for Customers with Past Due Bills

Co. Press Release – S&P Global Market Intelligence – Jul. 13, 2020

To help customers facing financial challenges related to COVID-19, **Cleco temporarily suspended service disconnects** and **late fees beginning March 13 through Aug. 31**.

"We recently received **direction from** our state regulatory agency, the **Louisiana Public Service Commission**, informing us that **disconnects** and **assessments** of **late fees can resume after July 16**, and **payment plans for past due bills can be created for up to 12 months**," said Shane Hilton, president of Cleco Power. "Realizing that the pandemic continues to impact many of our customers in various ways, we've developed a plan that goes above and beyond the regulatory requirements as we **delay implementation until Sept. 1**."

Cleco's long-term payment plan will give customers with past due bills incurred through July 16 **up to 18 months to pay**, **depending on** the **total amount owed**, and the company will not **reinstate disconnects** and **late fees** until **Sept. 1.**

Throughout **July**, **Cleco** will **notify customers** on the **specifics** of their **payment plans**, including the total amount due and the number of months to pay. Furthermore, the installment amount will be included on the customer's regular monthly bill.

To provide additional support, **customers who use KUBRA**, **Cleco's vendor** for **one-time electronic bill payments**, will continue to be **reimbursed** the **$2.50 processing fee**. This temporary reimbursement began April 15 and will continue **through Sept. 30**.

For more information, Cleco Power customers can visit a customer service office, call 1-800-622-6537, use the Contact Us form on cleco.com or direct message Cleco on Facebook at @ClecoPower.

KEY DATE:

March 13 Cleco temporarily suspended disconnects and late fees to assist customers.

July Cleco will mail letters to customers whose accounts will be on a long-term payment plan.

Aug. 1 Long-term payment plans for past due bills incurred through July 16 go into effect.

Sept. 1 Cleco will **reinstate disconnect procedures** and **late fees**.

Sept. 30 Cleco will **discontinue reimbursement** of the **KUBRA $2.50 processing fee**.

Cleco Corporate Holdings LLC is a regional energy holding company that conducts its business operations through its subsidiaries, Cleco Power LLC and Cleco Cajun LLC. Cleco Power is a regulated electric public utility company that owns 10 generating assets with a total nameplate capacity of 3,360 MWs and serves approximately 288,000 customers in Louisiana through its retail business and supplies wholesale power in Louisiana and Mississippi. Cleco Cajun is an unregulated utility company that owns eight generating assets with a total nameplate capacity of 3,555 MWs, with contracts serving nine Louisiana cooperatives, three wholesale municipal customers and one electric utility. For more information about Cleco, visit us at www.cleco.com.

Media Contact: Fran Phoenix (318) 48

Bankrupt in Just Two Weeks – Individual Investors Get Burned by Collapse of Complex Securities

by Akane Otani and Sebastian Pellejero – WSJ – Jun. 1, 2020

Seeking high returns, they poured savings into leveraged exchange-traded notes; the coronavirus downturn made some of them nearly worthless.

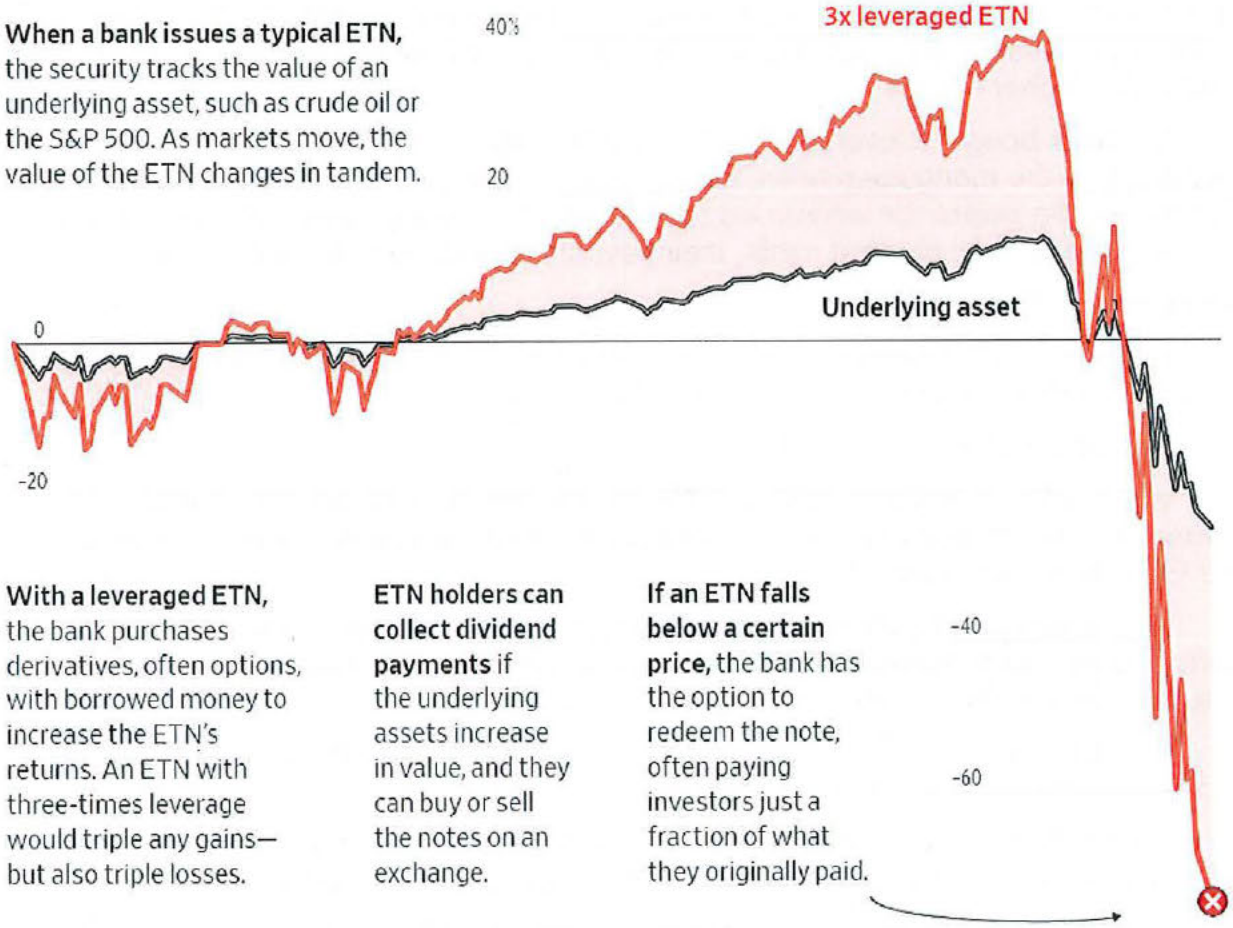
When William Mark (left) decided to get back into investing after the 2008 financial crisis, he looked past stocks and bonds. Needing to play catch-up with his retirement portfolio, the piping engineer decided to bet on a complicated product he hoped would deliver double-digit annual returns.

It worked so well – earning him 18% a year in dividends, on average – that he eventually poured $800,000 into the investments, called **leveraged exchange-traded notes**, or **ETNs**. When the coronavirus pandemic hit, he lost almost every penny.

Investing on Steroids

Leveraged exchange-traded notes are complex financial instruments that use debt to amplify returns, which also increases risk.

When a bank issues a typical ETN, the security tracks the value of an underlying asset, such as crude oil or the S&P 500. As markets move, the value of the ETN changes in tandem.



With a leveraged ETN, the bank purchases derivatives, often options, with borrowed money to increase the ETN's returns. An ETN with three-times leverage would triple any gains—but also triple losses.

ETN holders can collect dividend payments if the underlying assets increase in value, and they can buy or sell the notes on an exchange.

If an ETN falls below a certain price, the bank has the option to redeem the note, often paying investors just a fraction of what they originally paid.

"I'm 67 years old and I'm basically bankrupt in just two weeks," Mr. Mark said.

The pandemic-fueled economic downturn has sparked turmoil in nearly every financial market. It has taken a particularly brutal toll on investors like Mr. Mark, who wagered on the roughly **$7 trillion market for structured products: complex instruments that include ETNs, options-based strategies and certificates of deposits whose returns are tied to stocks or currencies**.

Banks and **brokerages advertised them** as **offering payouts both steadier** and **more lucrative than plain-vanilla investments** such as bonds or index-tracking funds. Most **professional money managers avoided them**. For many **less sophisticated retail buyers**, the market blowup taught the kind of **painful lesson** that comes with just about every economic crisis: There is **no such thing** as an **investment** that is **both safe and highly profitable**.

The market's collapse punished some banks that sold the products, which are considered derivatives. **Société Générale** SA, **BNP Paribas** SA and **Natixis** SA each **lost more than $200 million on their structured-products businesses this year**.

To understand how Mr. Mark and other investors were drawn to complex derivatives, it helps to go back to what happened after investment bank Lehman Brothers failed in 2008. Central banks cut interest rates to historic lows, which helped stabilize the financial system. It also lowered the income generated by the safest and most-stable investments, pushing investors into a risky hunt for bond-like products that could offer higher returns.

Mr. Mark bought a leveraged ETN issued by UBS Group AG that bet on companies that invest in the mortgage market, known as mortgage real-estate investment trusts. For others, the search for income led to investments in companies that bundled small business loans or oil pipeline rights, their payouts inflated by borrowed money.

Investing on Steroids

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3x leveraged ETN

When a **bank issues** a **typical ETN**, the **security tracks** the **value** of an **underlying asset**, such as **crude oil** or the **S&P 500**. As markets move, the value of the ETN changes in tandem.

With a leveraged ETN, the bank purchases derivatives, often options, with borrowed money to increase the ETN's returns. An **ETN with three-times leverage** would **triple** any **gains** –**but also triple losses**.

ETN holders can collect dividend **payments if** the **underlying assets increase in value**, and they **can buy or sell** the **notes on** an **exchange**.

If an **ETN falls below** a **certain price,** the **bank has** the **option** to **redeem** the **note**, often **paying investors just** a **fraction** of **what they originally paid**.

What all the products had in common was the **potential** to **deliver robust returns** at a time **when economic growth** was **slow and** a mountain of **sovereign** bonds around the world was **offering investors no income** at all.

Money manager ProShares made a name for itself focusing on riskier funds that would double or even triple the daily returns of conventional products, expanding its lineup from a handful of funds in 2006 to more than 130 ETFs today. **Brokers** working for **Citigroup** Inc., **Morgan Stanley** & Co., **UBS** and **Wells Fargo** & Co. **sold billions** of dollars of **risky exchange-traded funds**, or **ETFs**, in **2008** and **2009**.

Some traders said **large asset managers**, **turned off by** the **complexity**, mixed **record** and relatively **high fees**, **hardly ever bought the products**.

"If institutions aren't buying this, the **retail investor** shouldn't be either. Otherwise they're the **sucker** at the poker table **that doesn't know it**," said Larry Swedroe, chief research officer at wealth-management firm Buckingham Wealth Partners. "**If** a **product** is **so complex** that **you can't explain it to your partner**, then you **shouldn't buy it**."

In **2012**, **regulators sanctioned banks** for **failing** to **educate investors about** the **risks** of **leveraged ETFs**. **This year**, **Wells Fargo agreed** to **pay $35 million** to **settle claims** that its **financial advisers recommended inverse ETFs – funds that move** in the **opposite direction** of **what they track**—that were **too risky for retail clients**.

Pandemic Fallout Fear of an economic downturn sent investors rushing out of mortgage REITs, which use borrowed money to buy mortgage-backed securities.

This year, at least **15 ETNs managed by UBS** have **been taken** off the market **after tumbling in value**. **ETNs** run by **Citigroup** and other firms have **suffered significant losses**. When troubled funds are taken off the market, **investors** typically are **paid just** a **fraction of what they initially put in**.

Wells Fargo declined to comment, and UBS didn't respond to requests for comment.

Over the past decade, Wall Street packaged and sold many niche products engineered to get investors higher income than more plain-vanilla offerings. Their popularity soared during the bull market. UBS, Citigroup, JPMorgan Chase & Co., French bank Société Générale and Germany's Landesbank Hessen-Thuringen Girozentrale all offered individual investors ways to tap into structured products.

UBS created Mr. Mark's ETN in 2012, as mortgage-investment firms recovered from the financial crisis.

At least 15 ETNs managed by UBS have been taken off the market this year after tumbling in value.

On the surface, ETNs don't look much different than ordinary mutual or exchange-traded funds that track a group of companies. Both products allow investors to bet on the performance of anything from the U.S. stock market to the Swiss franc to wheat. But **unlike ETFs**, **ETNs don't own** the **assets they**

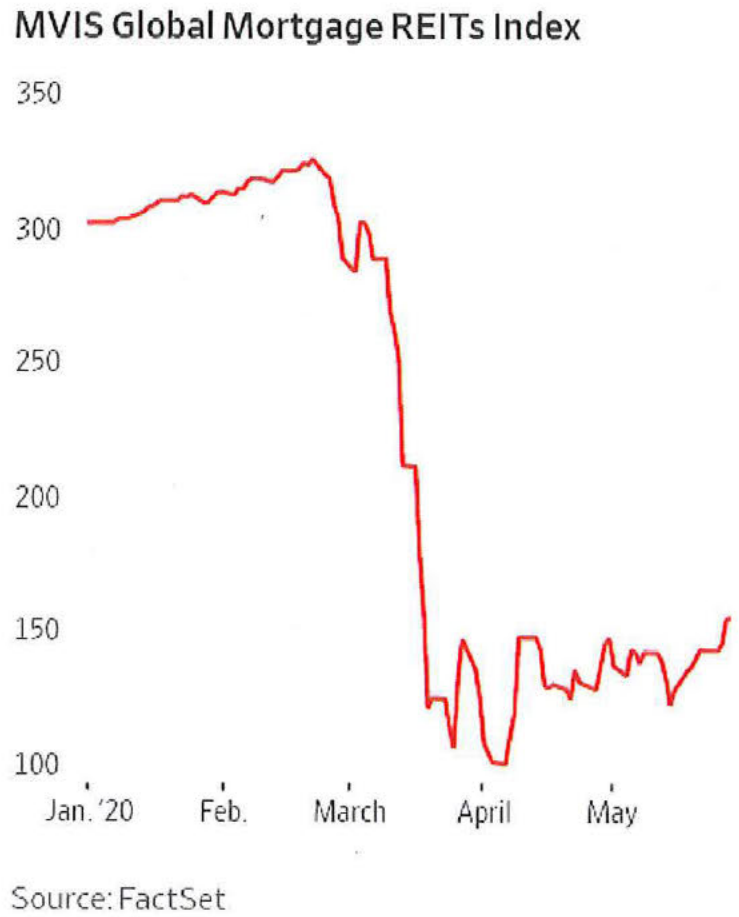
track. They are **debt instruments**. And the **banks that issue them** often have the **option** to **take them off** the **market** if their **value falls below** a **certain level**.

One reason ETNs have been hit hard in recent months as that many are leveraged, meaning they use borrowed money to amplify both gains, which also magnifies losses. Instead of rising 3% on a day that crude oil rises 3%, an oil ETN with three-times leverage aims to rise 9%. And instead of falling 3% on a down day, it would fall 9%.

It is "investing on steroids," said Todd Rosenbluth, director of ETF and mutual-fund research at CFRA, an investment-research firm.

Should any complex and risky financial investments be off limits for individual investors? Join the conversation below.

Some products layered complex strategies on top of each other. James Zhu, a 78-year-old retired college professor and engineer, invested his and his wife's life savings into ETNs based on payment streams from mortgage bonds, bundled together by investment firms and amped up with leverage.



So-called mortgage real-estate investment trusts, or mortgage REITs, return a significant portion of their profits to investors through dividends. When interest rates are low, mortgage REITs can look attractive to investors because they offer relatively high income.

James Zhu and his wife, Angela, invested their life savings into ETNs

By buying a leveraged ETN, Mr. Zhu was amplifying his bet on the mortgage market. Last year, shares of mortgage investment firms rallied. But this March, Mr. Zhu's bet blew up.

The coronavirus pandemic sent corporations scrambling for cash, increasing volatility in overnight borrowing markets on which mortgage REITs rely. That put pressure on their shares. ETNs making leveraged bets on mortgage investment firms nosedived.

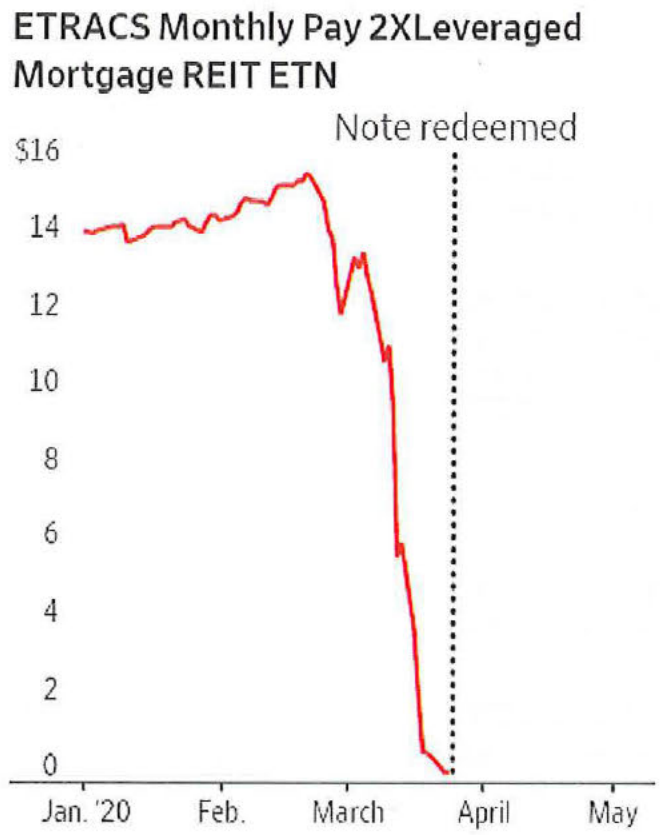
An ETN's Demise Leveraged exchange-traded notes tumbled as the coronavirus pandemic intensified. UBS's ETN tracking mortgage REITs fell so sharply the bank pulled the note off the market.

The ETN Mr. Zhu bought from UBS slumped to less than 25 cents a share, from around $14 at the start of the year. Once the value of the ETN fell below $5, UBS had the option to redeem it. It did so on March 17, notifying investors they would be paid out $0.201 per security held. That resulted in a loss of $700,000 for Mr. Zhu, who had purchased the ETN at $13.35.

"We're too old to play those games," Mr. Zhu said. "It's too difficult for us. We were just looking for basic income."

He is now suing his online brokerage, Inc., alleging the company made the ETN available to individual investors without providing sufficient disclosures. A representative for TD Ameritrade declined to comment.

Cleveland-based Brad Davis stumbled upon UBS's leveraged mortgage REIT ETN while browsing commission-free trading app Robinhood. Like Mr. Zhu, he wound up being hit with heavy losses after UBS redeemed the note.



Source: FactSet

Ultimately, the 33-year-old doesn't fault Robinhood for allowing him to trade the products. "I knew they were risky," he said.

Another concept that backfired: ETNs focused on the $122 billion market for loans to small and midsize firms through so-called business development companies, or BDCs. Like mortgage investment firms, BDCs tend to offer investors hefty dividends to qualify for tax benefits.

So far this year, shares of two of the largest such companies, FS KKR Capital Corp. and Ares Capital Corp., are down about 39% and 21%, respectively. BDCs managed by BlackRock Inc., Carlyle Group Inc., and Investcorp have fallen 45%, 33%, and 40% over the same period. The S&P 500 is down 5.8% by comparison.

ETNs run by Citigroup have suffered significant losses.

Now, many worry that loan losses will mount as small and midsize businesses struggle during the downturn. A drop in the value of BDC holdings can increase its leverage level, possibly exceeding thresholds set with investors.

"If you see the carnage you're seeing in the larger businesses, that is going to be a real problem for BDCs," said Dave Lafferty, chief markets strategist at Natixis Investment Managers.

Some investors place little blame on Wall Street for their losses, saying they traded products they knew were akin to gambling at a casino – **risky**, **difficult** to **time** and even **harder to profit from long-term**.

The **VelocityShares 3x Long Crude Oil ETN was issued by Citigroup**. Its prospectus says ETNs "may **not** be **suitable for investors who** plan to **hold them for a period other than one day," and noted it is "possible that you will suffer significant losses in** the **ETNs even if** the **long-term performance** of the **applicable Index** is **positive**."

Investors who sold the VelocityShares crude oil ETN at the end of last year could have come out positive, because nearly all markets, including commodities, rose on prospects at the time for global growth. The **pandemic sent crude prices down** sharply **to $14** a **barrel, from $61** a **barrel** at the **end** of **2019**. The **losses** were **amplified for holders** of the **VelocityShares ETN**. It **last traded at** around **16 cents a share**, **down from** about **$15 at** the **start** of the **year**. In April, **Citigroup pulled** the **ETN** off of the market altogether, adding in a statement that it would no longer issue notes of that variety.

'I don't think it's a good investment tool for most people,' said Randall Simpson, who has traded ETNs on and off for five years.

"I don't think it's a good investment tool for most people. It's like a craps game," said Randall Simpson, a 50-year-old project manager and environmental planner from Phoenix who has traded that ETN on and off for five years. Mr. Simpson said he has lost nearly 90% of his initial investment.

Years of investing, though, had taught him never to put a substantial portion of his portfolio into ETNs, so his losses have been manageable, if painful, he said.

Some investment professionals, including Messrs. Swedroe and Rosenbluth, contend that leveraged ETNs shouldn't be as accessible as they are to individual investors.

Some firms, including Vanguard Group, have stopped handling client purchases of leveraged or inverse notes altogether. Other online platforms catering to amateur investors continue to allow them to dabble in complex products.

Some banks, meanwhile, are issuing new ETNs to replace those that crashed just months ago. UBS has announced five new ETNs that will mimic five recently redeemed notes which covered BDCs, commodities, and oil and gas pipelines.

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Copper Prices Slip, Halting a Rebound

by Anna Isaac – WSJ – Jul. 6, 2020

Copper prices fell Friday, signaling a pause in the industrial metal's surge, on mounting concerns that the rally may have been overdone.

Copper futures for October delivery slipped about 1% to $6,030 a metric ton on the London Metal Exchange. The drop comes as investors struggle to reconcile signs of a global economic recovery with the surge in coronavirus infections in the U.S., which could deal a setback to manufacturers. Trading volumes are lower than usual with U.S. markets closed for the Independence Day holiday.

The fall comes after a rally of over 30% in the metal's price since its rout in March, reflecting optimism about the potential for a sharp recovery, as China and Europe lead large parts of the world in easing lockdown measures. That has helped erase most of the commodity's losses for this year.

Copper is considered a barometer for global growth, with traders dubbing it "Dr. Copper" in reference to its ability to augur turning points in the outlook. But some market watchers say traders are ignoring the threat posed by the record number of new daily infections in the U.S., and the risk that economic recovery world-wide could slow after the initial bounceback of recent weeks.

"There's a little bit of dislocation between copper's price and the economic reality, partly because it's been an asymmetrical recovery globally," said Wenyu Yao, a senior commodity strategist at ING Bank. "But so far, Dr. Copper did it: it delivered a V-shaped rally."

A revival in Chinese economic activity in recent months has helped propel copper prices higher. The commodity is particularly sensitive to the Asian manufacturing powerhouse, as the world's second-largest economy accounts for a large part of global demand for the metal. The reopening of major economies in Europe is also helping bolster demand for the industrial metal, analysts said.

Copper has outperformed metals such as aluminum and nickel, suggesting that its surge may have been "somewhat exaggerated," rather than tightly linked to supply and demand, according to Daniel Briesemann, a commodities analyst at Commerzbank.

Still, there are few expectations for a sharp correction in copper prices and some strategists expect the market to continue climbing.

Copper prices could reach as high as $6,500 a metric ton in the second half of this year, Bank of America analysts projected in June. Stimulus measures from governments around the world seeking to rebuild their economies would likely push prices higher, they said.

Supply disruptions from scrap collection to ore mining due to outbreaks of the virus may also continue to support copper prices. In Latin America, two major copper producers, Chile and Peru, face climbing infection rates. This has already caused significant supply disarray for the metal and some analysts expecting this to worsen in the coming weeks.

Virus could push unpaid utility bills to highest level in decades

By Mark Chediak and Gerson Freitas Jr – Bloomberg – May 11, 2020

With millions of people out of work, many utilities have stopped disconnecting customers for failing to pay bills.

WEC Energy Group Inc. and OGE Energy Corp. may face the utility industry's steepest hits to earnings as unpaid customer bills pile up, according to a research report.

The Milwaukee-based utility's pre-tax income may slide as much as 3.7%, Hugh Wynne and Eric Selmon, analysts with the investment research company SSR LLC, wrote Monday. They warn that the economic fallout from the coronavirus pandemic may drive uncollected electric and natural gas bills to the highest in two decades.

Other utilities that may face a significant drag on earnings include Oklahoma-based OGE, with an estimated 3% decline, Avangrid Inc.with a 2.9% drop and Dominion Energy with a 2.8% fall.

WEC Energy disputed the conclusions in the report, saying that under current regulations, it can recover bad debt expenses and is working with regulators and stakeholders to track bills for future recovery. The company is also working with federal and state governments to help customers manage their bills. OGE, Avangrid and Dominion didn't immediately respond to requests for comment.

Regulators are letting utilities defer virus-related expenses including those from non-payments for future potential recovery, WEC Chairman Gale E. Klappa said during an earnings call last week.

Dominion, meanwhile, can recover the costs of lapsed collections over time for nearly all of its gas utilities. Chief Financial Officer James Chapman said on the Virginia-based company's first-quarter earnings call that he does not expect "bad debt expense in excess of budgeted amounts to be a material driver for the year."

With millions of people out of work, many utilities have stopped disconnecting customers for failing to pay bills. While certain states allow utilities to recover the cost of unpaid bills through additional charges, utility cash flows will suffer until the rate increases go into effect, the analysts said. In addition, eleven states including Wisconsin are allowing utilities to track Covid-19 expenses, they said.

Annual changes in unemployment rates account for about 39% of the increase in uncollected electric bills and 45% of gas bills, according to the report. U.S. unemployment skyrocketed to 14.7% in April, the highest since the Great

Depression, as shelter-in-place orders forced businesses to shed millions of workers.

German banks' collective commitment on climate action is credit positive

By Christina Holthaus and Carola Schuler – Moody's Investors Service – July 6, 2020.

On 30 June, 16 German banks and other financial institutions signed a collective commitment to foster environmental sustainability in their lending and investment portfolios. The self-imposed commitment is credit positive because it will urge German banks to reassess lending and investment criteria under the auspices of sustainable finance, which will help them reach climate targets.

The commitment is based on the United Nations Environment Programme Finance Initiative (UNEP FI) commitment to climate action. It is also in line with the European policy agenda on economic sustainability efforts involving the financial sector and with the German regulator Bundesanstalt für Finanzdienstleistungsaufsicht's (BaFin) recommendation for good practices for sustainability risks.

Each participant commits to developing and implementing mutually accepted methods to measure the effects on climate of its lending and investment book, and managing its assets in line with climate targets of the Paris Agreement on Climate Change and Germany's Climate Protection Act and the Climate Action Programme. These targets include interim goals as well as achieving climate neutrality by 2050 to limit global warming to well below 2 degrees Celsius and striving to a maximum of 1.5 degrees Celsius. To reach these goals, the participants aim to focus on carbon, energy-intensive and transitional sectors first and publish sector-specific and scenario-based climate targets for their loan and investment books by the end of 2022.

The participants also commit to implementing a set of measures and reporting on their progress within the first 12 months following the initial agreement. The commitment does not apply to funds' business for which asset managers are obliged to implement investor orders. For those funds there will be only a gradual application of the commitment with no time frame.

That there are no details yet on concrete measures shows the early stage of the financial sector in dealing with environmental risks and sustainable finance in their daily operations. German banks in particular lag behind their international peers in terms of public commitments to sustainability and environmental exposures. None of the major German banks is among the 33 international banks that committed to take immediate action following the UN Secretary-General's Climate Action Summit in September 2019.

Furthermore, only one member of the German savings banks association and only a few small specialized members of the cooperative sector thus has signed on to the German collective commitment, which currently only includes 16

domestic and foreign financial institutions operating in Germany. These 16 institutions include Deutsche Bank AG (A3/A3 negative, ba11), Commerzbank AG (A1/A1 stable, baa2), UniCredit Bank AG (A2/A2 negative, baa2), Landesbank Baden-Wuerttemberg (Aa3/Aa3 stable, baa2) and ING-DiBa AG (A2 stable, a2).

Along with the banks' voluntary commitments, German regulators are intensifying their focus on sustainability risks and encouraging banks to integrate sustainability considerations into their business strategies. However, a 2019 BaFin survey found that only 1% of responding banks carried out a comprehensive analysis of sustainability risks and less than 1% said they considered environmental and climate-related risks a material risk for their bank. Even though 22% of respondents indicated that they plan to include these considerations in future analysis, the survey shows that German banks are at an early stage in assessing sustainable finance and environmental risk.

Economy Setback Seen Taking 10 Years to End

by Paul Kiernan and Paul Hannon

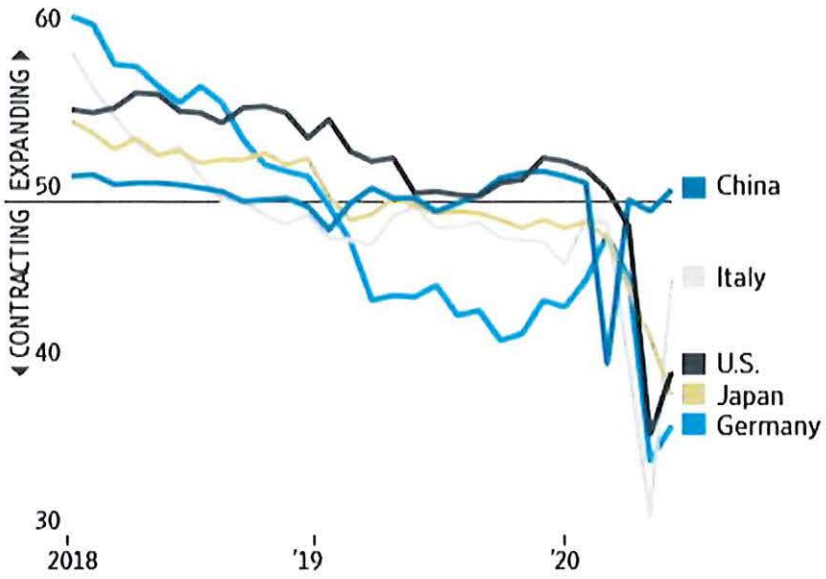
The **U.S. economy could take** the **better part** of a **decade** to **fully recover** from the **coronavirus pandemic** and **related shutdowns**, a U.S. budget agency said, as a series of surveys pointed to **continuing weakness** in **global manufacturing**.

The **Congressional Budget Office**, a nonpartisan legislative agency, said the sharp contraction triggered by the coronavirus caused it to mark down its 2020-30 forecast for U.S. economic output by a cumulative $7.9 trillion, or 3% of gross domestic product, **relative to** its **January projections**. **GDP isn't expected** to **catch up to** the **previously forecast level until** the **fourth quarter** of **2029**, the **CBO said**.

The roughly **$3.3 trillion** in **stimulus** programs enacted by Congress since March will **only** "**partially mitigate** the **deterioration** in **economic conditions**," the **CBO said**.

In most parts of the world, factory activity declined again in May, although at a slowing pace.

Purchasing managers indexes for manufacturing



Source: IHS Markit

"After you get the initial bounce of economic activity simply from removing the lockdowns, I think what we'll see is an economy that is running at a level of activity notably below where we were prior to Covid," said Michelle Meyer, chief U.S. economist at BofA Merrill Lynch. "It's going to take a long time to heal. There will be scars as a result of such a painful shock of the economy."

The CBO analysis came as new surveys showed **factories** in the **U.S. and abroad continued** to **reduce output** and **shed jobs in May**, though the pace of deterioration moderated as governments moved to ease coronavirus-related restrictions on their economies.

Surveys of purchasing managers at manufacturers in the U.S., Asia and Europe offered signs that the decline in global factory activity is starting to bottom out after the record fall seen in April. But sentiment remained negative, suggesting any recovery in the months ahead could be tentative.

The U.S. Institute for Supply Management's manufacturing index for May rose to 43.1 from an 11-year low of 41.5 in April. The index's core components all remained well below the 50 level that marks the threshold between contraction and expansion. A

majority of survey respondents said production and new orders worsened in May from April, and two-fifths reported lower employment levels.

The factory indexes add to other signs the U.S. and other countries might have reached an economic bottom, though recoveries could be slow. **Unemployment** is **up sharply across** the **globe**. Service industries are just starting to recover. And **consumer spending**, an **important catalyst** for the **U.S.** and other economies, **remains weak**.

"We're probably past the worst in terms of rates of de- cline, but things are still quite bad," said Joshua Shapiro, chief U.S. economist at Maria Fiorini Ramirez Inc. He said forward-looking aspects of the ISM survey are still "extremely weak."

The **CBO now expects U.S. GDP** to be **5.6% smaller** in the **fourth quarter** of **2020 than** a **year earlier**, a **sizable markdown from** its **2020 projection** of **2.2% growth** made at the **end** of **2019**.

While the **economy** is expected to **resume growing after this year**, the **pace** of **growth won't likely be fast enough** to **quickly make up for** the **ground lost during** the **coronavirus pandemic**. The **difference between** the **CBO's latest projection** for **GDP** and its **January forecast** "**roughly disappears by 2030**," **adjusted for inflation**.

The outlook for **weak manufacturing** is one factor weighing on the ability of global economies to turn around.

Tim Fiore, who manages the ISM's factory survey, said he expects further improvement in June as state governments allow more nonessential economic activities to resume. But until a vaccine or an effective treatment for Covid-19 is available, social-distancing efforts will limit the number of workers allowed on factory floors, likely restraining production.

Only in China, the first major economy to begin reopening after the novel coronavirus outbreak, did factories report an increase in activity. But the surveys suggested its nascent economic recovery is beginning to stall, with export orders falling sharply amid continued global efforts to contain the pandemic.

The surveys indicate the worst might be over for manufacturers, and activity could start to increase in coming months. But the road back to the levels of output and employment seen at the end of 2019 is set to be long and bumpy.

"Whether growth can achieve any serious momentum remains highly uncertain, however, as demand looks set to remain subdued by social-distancing measures, high unemployment and falling corporate profits for some time to come," said Chris Williamson, chief business economist at IHS Markit, the data firm that compiles most of the surveys outside the U.S.

In many countries, factory managers reported that restrictions on movement continue to make it difficult for them to operate at normal levels of output. But they also reported that weak demand is holding them back, with new orders continuing to fall.

In a sign factories don't expect conditions to improve rapidly, many reported further job cuts. In India and South Korea, those reductions in payrolls were the largest on record.

China – the first country exposed to the virus – entered lockdown earlier than other countries. It also exited its lockdown earlier, but May surveys of purchasing managers pointed to a large decline in export orders.

That was also true of South Korea, which chose not to impose mandatory lockdowns and focused instead on widespread testing and tracing of those infected by the virus, and the people with whom they had come into contact.

Separate figures released on Monday showed South Korea's May exports were down 23.7% from a year earlier to $34.86 billion following the prior month's revised 25.1% contraction.

China's Caixin general manufacturing index rose to 50.7 from 49.4, a sign that manufacturing activity increased after having fallen in April. A reading above 50 indicates an increase in activity, while a reading below that level indicates a decrease.

However, other manufacturing powerhouses continued to experience deep declines. Germany's PMI rose slightly, to 36.6 from 34.5, while Japan's PMI fell to 38.4 from 41.9.

PacifiCorp Launches Historic RFP for Renewables

By Steve Ernst – Clearing Up – Jul 10, 2020

PacifiCorp on **July 7** released a **request for proposals** seeking **4.3 GW of renewable energy and battery storage**, the **largest RFP in the utility's history** and **one of the largest calls for renewables in the industry**.

The utility's 2020 RFP seeks 1,823 MW of solar, 595 MW of battery storage and 1,920 MW of wind that can be operational by the end of 2024.

The company said "it will accept bids featuring different resource types and bid structures, including forms of power-purchase, battery storage, and build-transfer agreements."

PacifiCorp will not submit any self-build resources and therefore won't compete with independent power developers.

The RFP says projects must be able to achieve commercial operations by Dec. 31, 2024, but long-lead-time projects, such as pumped storage, can submit offers with commercial operation dates beyond that date. The RFP says a "reasonable on-line date" for a pumped-storage project is five years from signing a contract, or Dec. 31, 2026.

PacifiCorp is looking for proposals from resources capable of interconnecting with or delivering to its transmission system in either its east or west balancing authority areas (PACE and PACW, respectively).

The utility's transmission network reaches into 10 Western states, potentially making projects within the entire Western Interconnection eligible to bid into the RFP.

Spencer Gray, executive director of the Northwest and Intermountain Power Producers Coalition, said **the RFP heralds a batch of resource solicitations from Northwest utilities aimed at replacing coal-fired generation and reshaping the grid**.

PacifiCorp plans to close 16 of its coal units by 2030 and another four by 2038. The retirements would trim 2,800 MW from the company's 6,000 MW coal portfolio by 2030, and nearly 4,500 MW by 2038.

"This is the biggest, and the first" RFP aimed at replacing coal-fired generation, Gray said. "But **there will be multiple rounds of these** as utilities figure out their capacity needs and how renewables will replace coal."

The release of **PacifiCorp's 2020 RFP kicks off what could be the next "great phase" of regional renewables development**, Gray said.

"I think in 10 or 20 years we'll look back at the first wave of renewables development in the Northwest as 'Wind in the Gorge,'" he said, "I think in this next phase there will be a lot of development elsewhere around the region. I see a lot more solar on the rain

shadow side of the mountains, and utilities will be tapping into wind in Montana and Wyoming."

PacifiCorp's 2019 integrated resource plan placed new solar development in Utah as the heavy favorite to find a place in its portfolio.

Modeling done for PacifiCorp's 2019 IRP showed Utah's potential for cost-effective development of 3,000 MW of solar, paired with 635 MW of battery storage, between 2020 and 2037.

Solar development in Oregon also scored well during the early years of the 20-year resource planning horizon. Oregon has potential for 1,075 MW of new solar energy that would be paired with 244 MW of battery storage built between 2020 and 2033, the 2019 IRP said.

Solar development in Wyoming and Washington comes into play later in the utility's planning horizon. Between 2024 and 2038 the IRP showed Wyoming developing 1,415 MW of new solar, paired with 354 MW of battery storage, and Washington pairing 814 MW of solar with 204 MW of battery storage.

An RFP for renewables released in 2017 brought 1,150 MW of wind from Wyoming into PacifiCorp's portfolio.

The 2019 IRP's preferred portfolio also includes development of the Energy Gateway South project, a 400-mile transmission line that would run from southeast Wyoming into Utah, and is expected to be operational by year-end 2023.

The 2019 IRP also called for transmission upgrades and investments in Utah, Washington, Oregon, Idaho and Wyoming that "will facilitate continued and long-term growth in new renewable resources," according to the 2019 IRP.

PacifiCorp isn't alone in shopping for new resources. Most Northwest investor-owned utilities have ventured in search of new renewable resources, as well as resources that can contribute to meeting capacity shortfalls in both winter and summer.

Washington's largest utility, Puget Sound Energy, is preparing to test the market for capacity and demand response programs with a pair of requests for proposals. The utility's draft RFP shows PSE acquiring 200 MW of capacity in 2023 and in 2024, with another 353 MW in service at the end of 2025 (CU No. 1959 [9]).

Spokane-based Avista on June 26 released an RFP for 120 aMW of renewable energy.

NorthWestern Energy, Montana's largest utility, also released an RFP on June 26 looking for energy and capacity proposals of 25-300 MW capable of delivering to a point of interconnection on NorthWestern's system, beginning in summer or fall 2020.

Portland General Electric's updated 2019 IRP shows a capacity need of about 250 MW beginning in 2021, increasing to about 270 MW in 2023 and reaching 697 MW as contracts begin expiring at the end of the action-plan window in 2025.

Later this year, PGE is likely to release an RFP seeking 150 aMW of renewable energy and another for "non-emitting dispatchable capacity resources" that would also take into consideration the long lead times needed to develop a pumped hydro storage project.

Warren Buffett's Berkshire Hathaway Reports $49.7 Billion Loss for First Quarter

By Geoffrey Rogow – WSJ – May 2, 2020

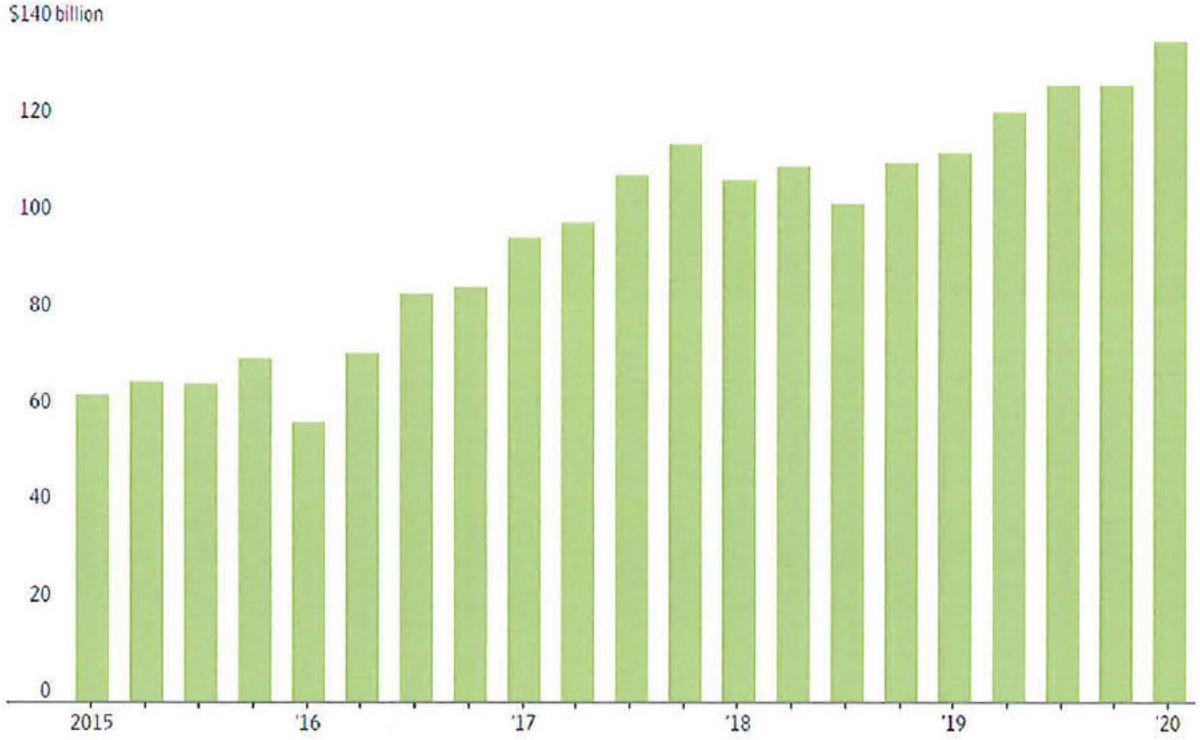
Warren Buffett's Berkshire Hathaway Inc. swung to a first-quarter loss as the selloff in markets hit the company's vast investments, though the company's operating earnings rose in the quarter.

Berkshire's earnings are especially volatile due to an accounting rule that went into effect in 2018 requiring companies to include unrealized investment gains or losses in their net income. Berkshire holds large stock investments, and their quarterly changes in value can have a big effect on Berkshire's net income.

Berkshire reported a first-quarter loss of $49.7 billion, or $30,653 per Class A share equivalent, from $21.66 billion, or $13,209 a share, in the year-earlier period.

Operating earnings, which exclude some investment results, rose to $5.87 billion from $5.56 billion in the year prior. Mr. Buffett has said operating earnings are more reflective of Berkshire's performance.

Berkshire Hathaway's cash and short-term investments, quarterly



Source: FactSet; the company (4Q 2019 and 1Q 2020)

Declines in profitability at the company's railroads, utilities and energy and insurance underwriting divisions were offset by a rise in insurance investment income.

The earnings report comes after a tumultuous quarter in markets from the coronavirus pandemic. Mr. Buffett has a reputation for purchasing companies or making loans during moments of financial crisis, but his firm has been largely silent as all types of industries—from airlines and hotels to even some financial firms—face unprecedented hardship.

In Berkshire's quarterly report, the firm said the spread of coronavirus began to "significantly affect our operating businesses in March and will likely adversely affect nearly all of our operations in the second quarter." The firm added that the duration and effects of the pandemic couldn't be reasonably estimated at this time.

Some analysts and longtime Berkshire stockholders say many of the beaten-down companies over the past month are the types of firms that don't fit Berkshire's investment criteria.

"The greatest stock picker of all time can't buy any of this," said Bill Smead, chief executive of Smead Capital Management Inc., which holds Berkshire shares.

Moreover, Berkshire is already heavily invested in some of those industries, such as energy, airlines and financial services, according to Mr. Smead.

Mr. Buffett will likely give his take on the pandemic later Saturday at the company's annual meeting in Omaha, Neb. Often called "Woodstock for Capitalists," this year's meeting will be vastly different from the past when thousands of investors packed into a stadium to hear Mr. Buffett speak.

This year, only Mr. Buffett and Greg Abel, Berkshire's vice chairman of non-insurance operations, will be present in Omaha. That means Mr. Buffett's most trusted partner, Berkshire Vice Chairman Charlie Munger, won't be in attendance.

Messrs. Buffett and Abel are set to answer questions that come from shareholders and are reviewed by a group of handpicked journalists this afternoon.

The conglomerate runs a large insurance operation as well as railroad operations, utilities, industrial manufacturers and retailers. Its holdings include recognizable names like Dairy Queen, Duracell, Fruit of the Loom, See's Candies and Geico. Berkshire's insurance businesses sit at the core of its moneymaking machine. Insurance brings in billions of dollars of "float," upfront premiums customers pay and that Berkshire invests for its own gain.

In the past few weeks, Geico joined many other insurers by giving customers premium refunds in response to fewer drivers on the road and fewer accidents. Meanwhile, the broader insurance industry, lawmakers and business owners are debating how much insurers will be on the hook for claims related to the coronavirus pandemic.

In the first quarter, Berkshire bought back $1.7 billion of its own shares, the company said. Berkshire changed its buyback policy in 2018, and some shareholders have said they would like the company to spend significantly more cash repurchasing its stock.

The 89-year-old Mr. Buffett, whose shrewd investments have earned him the nickname "the Oracle of Omaha," still has plenty of cash on hand and could make a significant investment at any moment. Berkshire held about $137.3 billion in cash at the end of the first quarter, up from $128 billion at the end of the fourth quarter.

Class A shares closed Friday at $275,800, down 18.8% for the year.

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In Colorado, Retirement Date Set for Coal-Fired Craig Station Unit

by Bridget Reed Morawski – S&P Global Market Intelligence – Jul. 8, 2020

The owners of a coal-fired power generating unit in Moffat County, Colo., set a retirement date for their asset.

The **410-MW Craig Unit 2 will retire Sept. 30, 2028**, according to Tri-State Generation and Transmission Association Inc., one of the unit's **five owners**.

Tri-State announced in January that **Craig Unit 1** would **close by** the **end** of **2025** and **Units 2 and 3** would follow **by 2030**, in keeping with the utility's plan to shutter its entire Colorado-based coal-fired generation fleet decades earlier than technologically necessary. Tri-State said in a July 8 news release that the plan announced previously for **closing** Craig **Units 1 and 3** has **not changed**.

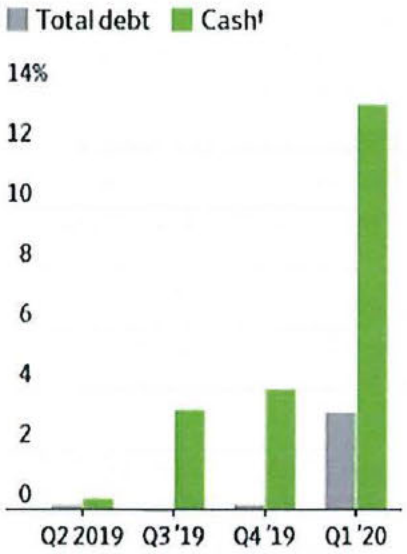
The **other owners** of **Craig Units 1 and 2** are **PacifiCorp**, **Platte River Power Authority**, **Salt River Project** and **Xcel Energy Inc**., which **operates** in-state **as Public Service Co**. **of Colorad**o. Tri-**State alone owns Craig Unit 3**.

Tri-State's coal-specific decarbonization effort comes as **several** of its **member utilities** have **sought** to **abandon ship** and **exit their contracts early**, which, for some, was in part over a desire for cleaner, cheaper power.

Crisis Boosts Cash Allure to Firms

by Thomas Gyrta and Theo Francis – WSJ – Jun. 22, 2020
Kristin Broughton and Mark Maurer contributed to this article.

Median quarterly change in cash and debt for S&P 500 companies*



*Excludes financial companies †Includes short-term investments
Source: S&P Global Market Intelligence

Giant **companies from McDonald's** Corp. **to Intel** Corp. are **husbanding cash**, **cutting costs** and **tapping debt**, all moves that **bolster** their **resilience amid** persistent **uncertainty** wrought by the new **coronavirus pandemic**.

At the same time, corporate leaders and investors are gauging when it will make sense to economize less and spend more to avoid losing out to rivals once the recovery begins in earnest.

"I would just want to get through a couple more months of understanding what that recovery looks like," Robert Mc-Mahon, chief financial officer of life-sciences company Agilent Technologies Inc., told investors in early June. "**Liquidity** is still an asset that we want to have in our back pocket. We have a lot of it, and I think it will serve us well versus some of our competitors when we come out of this."

As the pandemic swept the **U.S.,** large **companies significantly increased cash** and **short-term investments** as well as total **debt** – much **more rapidly than** they did **in** the **preceding quarters**, according to a Wall Street Journal analysis of financial data from S&P Global Market Intelligence.

For S&P 500 companies, the median increase in cash and short-term investments was 13.9% in the March quarter, compared with less than 4.1% in the prior three quarters, the analysis found. The degree to which firms spent or saved those funds will be evident when they report second-quarter results starting next month.

PepsiCo Inc. borrowed $7.6 billion in the first quarter, doubling the cash on its balance sheet. Hilton Worldwide Holdings Inc. raised $1 billion by selling loyalty points. Home builder Lennar Corp. paused land purchases. Carnival Corp. has put six of its ships up for sale. And Agilent was among those that continued to draw on operations abroad during the spring by repatriating foreign profits.

Companies stockpile cash in a crisis for much the same reason households do: It provides flexibility in an uncertain environment, protecting against further crises or suddenly parsimonious capital markets. It also serves as ready fuel once sustainable growth resumes and new investment makes sense.

"The real clarity is going to be when they know what spikes in the virus mean for consumer behavior," said Blair Effron, co-founder of investment bank Centerview Partners LLC. Companies know the economy is bad now, he said, but need to better understand what it will look like in coming months.

Central bankers around the world have committed to providing liquidity to banks and companies. As a result, in contrast to the financial crisis of 2008 and 2009, when lending and investment capital evaporated suddenly, healthy companies aren't having difficulty getting access to cash, making it even easier to keep their tanks full.

Cheap debt has made that reflex easier to indulge even while spending to expand or maintain operations.

The Federal Reserve cut interest rates in March near zero and has been buying Treasurys and mortgage-backed securities. It said it stands ready to buy corporate bonds, pushing down borrowing costs.

Even embattled businesses have been able to fill their coffers. Gap Inc. said in early May that it had raised $2.25 billion, about a month after it had closed its U.S. stores and drawn down its full $500 million credit line. Gap later closed that credit line and has yet to tap its replacement, a spokeswoman said.

Hilton borrowed $1.5 billion from its credit line, which it called a precautionary measure, closing its books for the March quarter with more than triple the cash that it had on Jan. 1. It sold loyalty points and new debt to raise an additional $2 billion in April.

"Holding cash gives more flexibility to the company in terms of what it should do," said Lee Pinkowitz, an associate professor of finance at Georgetown University whose research has shown that investors value cash more highly in a crisis. The pandemic, civil unrest and political turmoil are stirring up the kind of fear that leads to cash hoarding, he added. "The higher the uncertainty, the more valuable that option is."

Among nonfinancial companies in the S&P 500, half increased their debt by at least 3.38% during the first quarter from the fourth quarter, according to the Journal analysis. By contrast, in the prior three quarters, the median increase in debt for the companies never exceeded about 0.2%.

Much of the proceeds were just stashed away. For example, McDonald's borrowed $4.8 billion – increasing total debt by 10% – and ended the first quarter with cash up $4.5 billion. Chip giant Intel was similar, borrowing $10.4 billion, increasing its total debt 35% and ending the quarter with cash and related investments up $7.7 billion.

Not every company increased its liquid reserves. Apple Inc., which has accumulated one of the biggest hoards of cash and investments, spent it down by about $13 billion in the first quarter, or about 12%. In April, finance chief Luca Maestri said Apple's strong balance sheet, cash flow and access to capital markets mean the company hasn't faced liquidity problems.

Smaller companies, too, have used a range of tools to conserve cash. Jeans maker Guess Inc. slashed capital expenditures by more than 60% and operating costs by 30% compared with a year earlier based on revised models of consumer demand, and extended payment terms with some vendors, Chief Financial Officer Katie Anderson said.

Choice Hotels International Inc. laid off or furloughed about 20% of its workforce, temporarily eliminated its 401(k) match and paused share buybacks and dividends,

among other cost cuts, its finance chief, Dominic Dragisich, said. Those and future cost-cutting opportunities give the company enough liquidity to continue day-to-day operations for three years if necessary, Mr. Dragisich said.

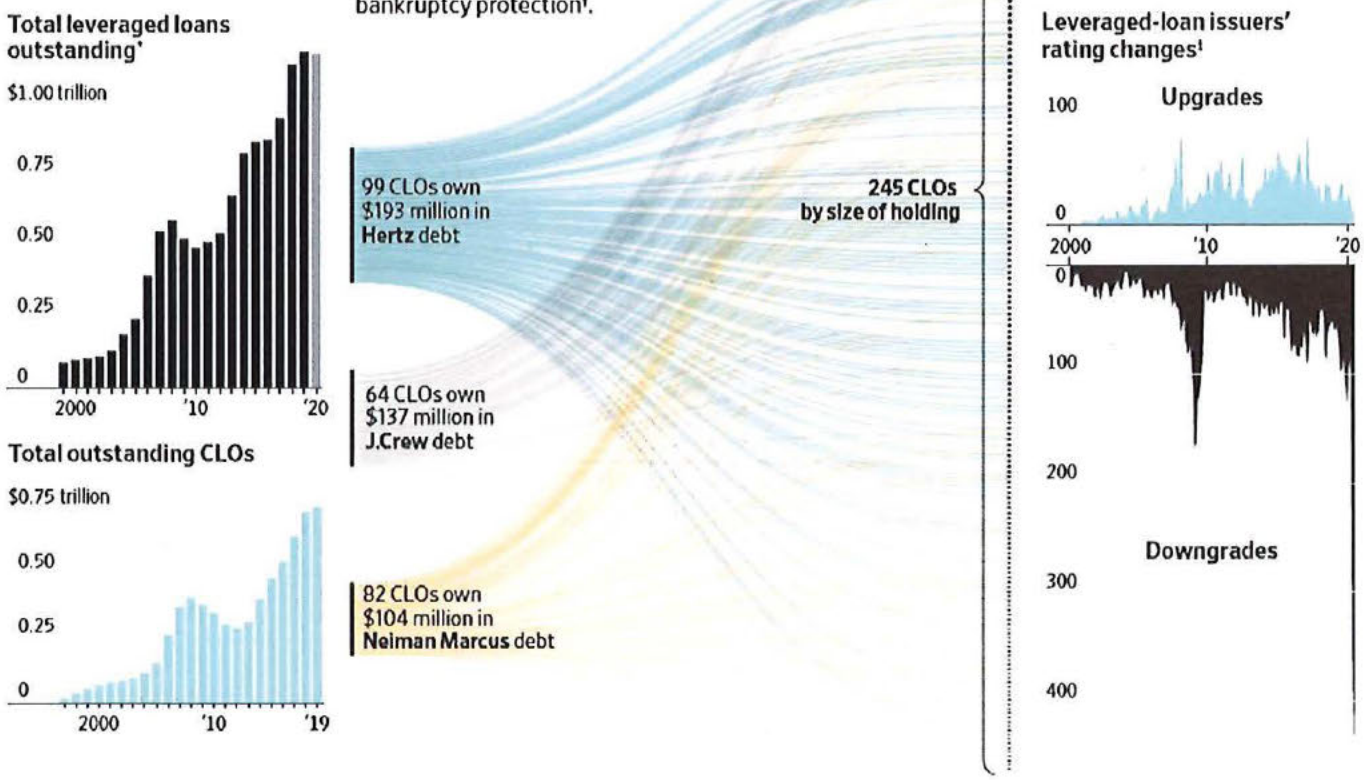
Crisis Upends Corporate Borrowing Binge

by Cezary Podkul and Ana Rivas – WSJ – Jun. 25, 2020

Leveraged loans, which fund buyouts, have doubled since 2008, with collateralized loan obligations buying more than 60%.

As of March, 245 CLOs owned about $435 million of loans owed by Hertz Global Holdings, Neiman Marcus and J.Crew. In May, all three filed for bankruptcy protection[1].

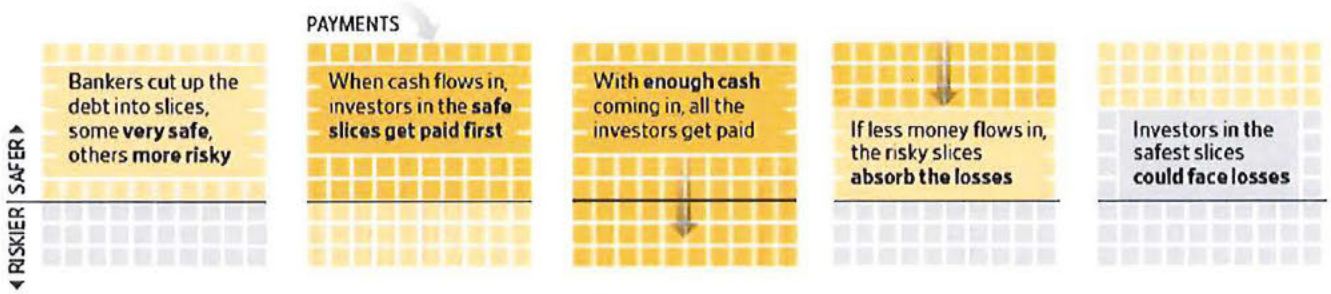
The companies that rate bonds say billions of dollars in debt has suddenly gotten riskier and is less likely to pay off.



CLOs buy pools of loans and hire bankers to sell bonds backed by the loans.

Companies pay their loans and the cash flows into the CLOs. In bad times, less money flows in and investors in the safe slices get paid first. The risky slices of the CLOs act like a cushion and absorb the losses to protect the safe securities.

As more debt-laden companies struggle, less cash will flow into CLOs.



*Through June. †Based on CLO holdings reported as of March. Loans and corporate entities consolidated by company name. ‡Shows rolling three-month tally of downgrades and upgrades for loans in the S&P/LSTA Leveraged Loan Index, current through May.
Sources: S&P Global LCD (leveraged loans outstanding, issuer rating changes); IMF (total outstanding CLO debt); Trepp CLO (Hertz, J.Crew, Neiman Marcus holdings).

The coronavirus pandemic hit U.S. businesses at a bad time. Companies had loaded up on debt after years of low interest rates, buyouts and increasingly lax lending standards.

Much of that borrowing was bankrolled by an elaborate ecosystem of debt funds called collateralized loan obligations. CLOs buy up risky corporate loans and turn them into supposedly safe bonds that are bought by banks, insurance firms and other global investors.

Those securities are now struggling because of the economic slowdown. Debt-laden companies like Neiman Marcus, Hertz and J.Crew have already gone bust. That has ricocheted back to the CLOs that own their loans. Prices have been volatile and investors are reassessing the risks of CLOs, crimping the supply of credit when it is needed most.

One reason why investors believe CLOs are safer than the loans they hold is diversification. It is less risky to own a pool of loans from companies in different industries than one loan from an individual company.

Diversification has helped CLOs perform well during past recessions. This time is different because while some industries such as retailers and airlines were especially hit hard by the sudden shock of the coronavirus, few were spared. That takes away some of the benefits of diversification.

The big rise in corporate borrowing in recent years magnified the impact because companies entered the downturn with heavier debt loads. **Since early March**, about **30% of debt packaged into U.S. CLOs** has been **downgraded or placed on watch** for **possible downgrades**, according to ratings firm **S&P** Global Inc.

Pieces of such **loans** get **bought** up **by dozens**, sometimes **hundreds of CLOs**. So as the defaults and bankruptcies mount, so will the potential hit to investors who bought CLOs backed by the loans. **Some 245 CLOs were exposed** to **loans owed** by **just three companies that declared bankruptcy in May**. The **government stimulus**, the **Fed**eral Reserve's **rescue** of the **markets** and a **modest economic rebound** appear to have **saved CLOs from big losses**. The **risk now** is that **investors** that have been big buyers of CLOs **will stay away**. A Japanese bank that owned about 10% of all CLO debt has already done that. The slowdown in lending could make it hard for companies that need cash and could limit deal making. **If companies can't borrow,** that could become a **drag on** the **economic recovery** and prolong the slowdown caused by the pandemic.

DC Circuit Upholds Landmark FERC Order Aimed at Boosting Energy Storage

by Zack Hale – S&P Global Market Intelligence – Jul. 10, 2020

A federal appeals court July 10 **upheld** a major **F**ederal **E**nergy **R**egulatory **Commission order** designed to **remove barriers** to **energy storage participation** in **wholesale electricity markets**.

The ruling by the **U.S. Court of Appeals** for the **District** of **Columbia Circuit** handed a win to storage supporters and **dealt** a **loss** to a **coalition** of **state regulators and utility petitioners** that **argued** the **order** had **exceeded FERC's authority under** the **Federal Power Act**, or **FPA**.

FERC issued **Order 841** in **February 2018**, a long-awaited final rule aimed at removing barriers that keep energy storage resources, such as **batteries** and **flywheels**, from **more fully participating** in **markets run by** the **nation's regional transmission organizations** and independent system operators.

Order 841 **directed each RTO** and **ISO** to **establish market rules** that **accommodate** the **participation** of **storage resources** in their **capacity**, **energy** and **ancillary services markets** to the extent possible based on those resources' physical and operational characteristics. The order specified that the **market rules must apply** to **storage resources over 100 kW** that **supply energy to** the **grid**.

In **May 2019**, **FERC** issued **Order 841-A** that largely **affirmed** the storage rule. In doing so, the **commission refused** to **include** an **opt-out provision called for by** groups including the **N**ational **A**ssociation of **R**egulatory **U**tility **C**ommissioners, **E**dison **E**lectric **I**nstitute, **A**merican **P**ublic **P**ower **A**ssociation, **and A**merican **M**unicipal **P**ower Inc.

Jurisdictional Dispute

The **state regulators and utility groups subsequently sued** at the **D.C. Circuit**, arguing that FERC's move to **bar states** from broadly prohibiting storage resource participation in wholesale markets interferes with their right under the FPA to regulate their own distribution systems.

Specifically, the groups argued that FERC is impermissibly regulating distribution systems by prohibiting states from blocking storage access to wholesale markets. They also asserted that FERC acted arbitrarily and capriciously by **refusing** to **allow states** to **opt-out** of the storage participation requirement in the **same manner as** it **allowed states** to **opt-out of certain requirements** of the agency's landmark **demand response** rule that was **later upheld by** the **U.S. Supreme Court**.

While that 2016 high court decision (*FERC v. EPSA)* did not rest on the inclusion of an opt-out provision, the petitioners recounted that the ruling cited the provision's efficacy in promoting the goals of cooperative federalism under the FPA. And they maintained that unlike its order for demand response resources, which are paid to not consume energy, FERC's rationale for its storage orders ignored that storage resources can inject energy into the grid. The petitioners said this creates a greater need from states to exercise their authority over those resources to maintain grid reliability.

DC Circuit's Ruling

The **D.C. Circuit rejected** those claims, concluding that Order 841 should stand because it "solely targets" the manner in which a storage resource may participate in wholesale markets. In doing so, the court noted that "there is little doubt" the order will entice storage resources to seek access to the federal marketplace. But "that is the type of permissible effect of direct regulation of federal wholesale sales that the FPA allows," Judge Robert Wilkins wrote for the court.

"Nothing in Order No. 841 directly regulates those distribution systems," Wilkins said. "States remain equipped with every tool they possessed prior to Order No. 841 to manage their facilities and systems."

The D.C. Circuit further explained that the U.S. Constitution's Supremacy Clause "creates uneven playing fields" that extend to the FPA's two separate zones of jurisdiction. Because FERC has exclusive authority over wholesale market participation, the Supremacy Clause effectively bars states from interfering with that jurisdiction, the court said.

Addressing petitioners' arbitrary and capricious claims, the court also sided with FERC by finding that the commission provided a reasoned basis for deciding not to include an opt-out provision. In doing so, the court deferred to FERC's reasoning that the **benefits** of **broad storage access to wholesale markets** – including increased competition, enhanced grid reliability and lower rates – **outweighed** the **costs to states**.

Under its ruling, however, the court said **states** will **retain authority** to **prohibit local storage resources** from **participating** in **interstate and retail markets simultaneously**, meaning **regulators can force storage resources to choose between the two**. And **FERC cannot interfere with state-level safety and reliability requirements for storage resources**, the **court said**.

"Petitioners are likely correct that litigation will follow as states try to navigate this line, but such is the nature of facial challenges," Wilkins said, noting that the ruling does not foreclose judicial review in future related conflicts.

FERC Chairman Neil Chatterjee cheered the ruling during a July 10 call with reporters.

"I have said repeatedly that I think [with] 841, we may look down the road and say it was one of the single most significant actions taken by a government agency to address carbon mitigation and the transition to a clean energy future," Chatterjee said.

The ruling was also met with praise on social media by former commissioners who helped craft Order 841.

"The decision of the D.C. Circuit upholding FERC Order 841 on energy storage is a very important case for the future of storage technology," former FERC Chair and commissioner Cheryl LaFleur wrote on Twitter. "Happy to see bipartisan support for this FERC rule in the years since, and now judicial validation."

Joining in the opinion were Judges Merrick Garland and Judith Rogers **NARUC v. FERC** (**No. 19-1142**)

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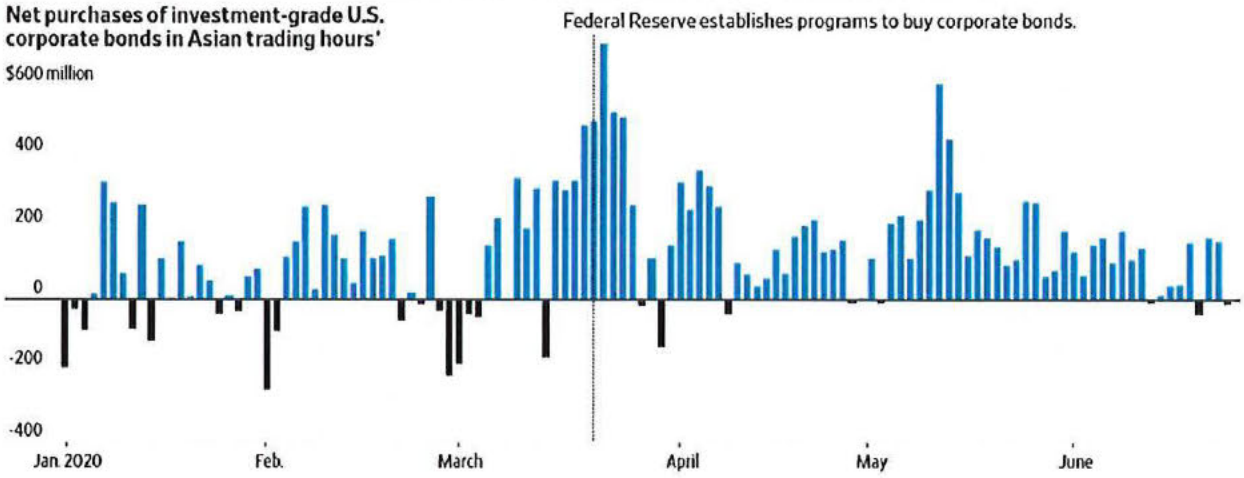
Debt from American Companies Lures Asian, European Investors

by Joe Wallace and Frances Yoon – WSJ – Jun. 29, 2020
Pat Minczeski contributed to this article.

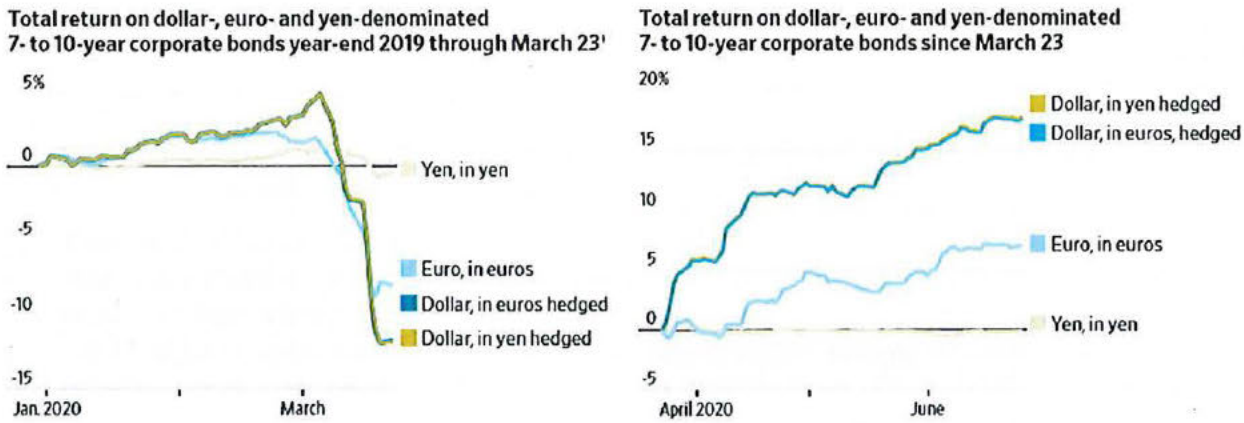
Currency-hedging costs have dropped for international investors.

Overseas investors are **flocking to buy U.S. corporate bonds**, aiding a recovery in credit markets that were thrown into disarray by the pandemic.

Financial institutions in Asia and Europe have continued to snap up American corporate debt, enticed by higher yields than those on offer in their domestic markets.



Steps taken by the Federal Reserve to keep credit flowing through the U.S. economy, combined with the **more attractive yields offered by American corporate debt**, have **drawn Asian** and **European investors since late March**. Currency-hedging costs have also dropped for international investors, propelling demand.



*Data through Thursday. ¹Bonds sold by nonfinancial companies except Japan's bond index, which includes financial companies, primarily banks.
Sources: Financial Industry Regulatory Authority via BNP Paribas (net purchases); ICE Data Services (total return)

The surge in **buying from abroad** could help sustain the rally in U.S. corporate bonds, **preventing** an **increase in borrowing costs** at a time American companies are bingeing on debt. Since prices and yields move in opposite directions, higher prices have made it cheaper for companies contending with a slump in sales to borrow new debt.

Both corporate bonds and stocks wobbled last week when investors became concerned that a jump in coron
avirus cases could jeopardize a nascent economic recovery.

The **extra yield** that **investors demand to hold corporate investment-grade bonds** in the ICE BofA U.S. Corporate Index **instead** of **safe Treasurys ticked** up to **1.62 percentage points**. This gap, a measure of how risky investors perceive corporate bonds to be, remains well below its **peak** of over **4 percentage points** in **late March**.

Bond prices have **powered higher since then**, fueled by the Fed's efforts to bolster debt markets. This week, investors may get fresh cues about the central bank's future steps when Chairman Jerome Powell testifies in Congress and the minutes of the Fed's most recent rate-setting meeting are released.

Asian investors have been particularly big buyers of U.S. corporate debt, shifting their focus from the government bond market. That is because the **yield on Treasurys** has **dropped to historic lows**, driven by a global recession, the Fed's asset purchases and the fall in U.S. interest rates to just above zero. **South Korean** and **Taiwanese life insurers**, as well as **Japanese banks**, are **lapping up American corporate bonds instead**.

Seoul's Kyobo Life Insurance Co., which manages around $100 billion in assets, is one such buyer. The life insurer boosted its investment in U.S. corporate debt by 17% from a year ago to $7 billion by purchasing bonds from companies including Johnson & Johnson, Walmart Inc. and Microsoft Corp. that don't come due for 20 years or more.

"We sold our Treasury holdings to buy U.S. corporate credit to take advantage of a spike in corporate-bond spreads," said Matt Lee, head of overseas investments at Kyobo. The firm has **sought companies with high credit ratings and steered clear**

of those that could suffer during an economic downturn, such as energy producers, he said.

Mr. Lee plans to buy more such debt, reasoning that support from the Fed will stop corporate-bond prices from tumbling again. Competition to invest in existing debt is fierce, so Kyobo has purchased new bonds when companies issue them.

Asian and European investors who **ventured into U.S. credit** when the market sank three months ago have been rewarded with rich returns. **Since March 23, yen-denominated corporate bonds** with **maturities** of **seven to 10 years** have **returned minus 0.2%, based** on an ICE BofA index. **Japanese investors** who **bought U.S. bonds** with **similar due dates**, **hedging** the **proceeds back into yen**, have **earned** a **much greater 17.6%.**

In a sign of rising foreign demand, overnight trading in U.S. corporate bonds has shot up. An average of $181 million in investment-grade U.S. bonds have been bought each day in Asian trading hours since the third week of March, net of sales, according to data from the Financial Industry Regulatory Authority. That is **up** almost **170% from** the **first two months of 2020**, said BNP Paribas credit strategist Dominique Toublan.

Yields on U.S. bonds, which 01, have **dropped sharply since the end of March after the Fed began an aggressive program to backstop credit markets**.

Still, U.S. yields remain higher than those in Japan and Europe, partly because more American companies are expected to default as a result of the coronavirus crisis. Another factor is that yields on Treasurys, which investors price corporate bonds against, are higher than on German and Japanese government bonds.

Investment-grade U.S. corporate bonds included in an ICE BofA index paid a yield to maturity of 2.26% Friday. Bonds in a parallel index for Japan paid 0.52%, while investment-grade bonds in the euro-zone paid 0.9%.

For most overseas investors, it isn't enough to compare yields in the U.S. and at home. Foreign fund managers who own American corporate bonds, including Mr. Lee, typically hedge some or all of them back into their domestic currencies.

To insulate bond investments from swings in the dollar, investors lock in a rate at which they could convert the proceeds back into euros or yen using derivatives.

Currency-hedging costs have dropped since the Fed cut its interest-rate target to 0-0.25%. In May and June, the aver**age annualized expense for investors hedging out of dollars using three-month forward contracts was 0.58% for yen and 0.8% for euros,** according to BNP Paribas.

Deep Dive into ROE Methodologies Reveals Much Lies below the Surface

by Dan Lowrey – S&P Global Market Intelligence – Jun. 29, 2020

Among the most contentious and debated elements of a utility rate case is determining the **return on equity**, or **level of profit**, that the **regulated utility** is **authorized**. This is because methodologies for calculating the required ROE are highly subjective and inputs are variable. **No one method** is **universally recognized**, and utility commissions often incorporate multiple methodologies and other subjective interpretations in rendering their final decisions. The **authorized ROE** is a **key component** in **determining** a **utility's revenue requirement** and **ultimately whether base rates will increase** or **decrease and by how much**.

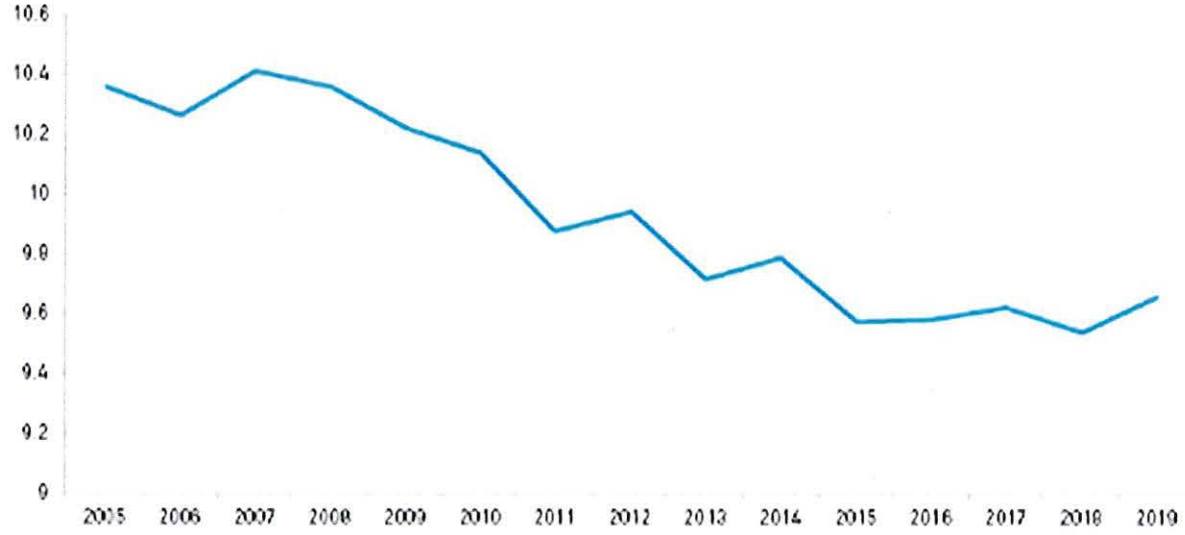
As natural monopolies, **utilities** are **provided** the **opportunity** to **earn** a **regulated rate of return** that **incorporates** the **costs of debt** and **equity** and any **other sources of capital**, **if applicable**, **on its rate base**. As established by legal precedent, the **return should be sufficient** to **allow** the **utility** to **attract capital commensurate** with its **level of risk**, to **assure confidence** in the **company's financial integrity** and **support** the **company's credit**. **Commissions must** also **weigh** the **implications on ratepayers**, **ensuring safe** and **reliable utility service** at a **reasonable cost.**

In a Topical Special Report, "The rate case process: establishing a fair return for regulated utilities," Regulatory Research Associates discusses the methods used in regulatory proceedings to establish an authorized ROE for utilities and the trends in ROE authorizations. The report is an addendum to RRA's popular utility regulation 101 report series. In separate recent report, RRA recently highlighted the key aspects of the rate case process and rate base.

Equity returns authorized in electric and gas utility rate cases have generally trended downwards over the past 15 years consistent with declining interest rates. In addition, the proliferation of automatic adjustment and investment recovery mechanisms that reduce utility business risk have been cited, at times, as a contributing factor by commissions in authorizing lower ROEs.

The **table below excludes ROEs** determined in limited issue proceedings and certain rate cases decided in **Alaska**, which represent **outliers** from the general sample. The Regulatory Commission of Alaska typically awards much higher than average ROEs to compensate utilities for the difficult terrain and environmental conditions they face as well as regulatory lag associated with lengthy rate case proceedings.

Average authorized ROE (%)

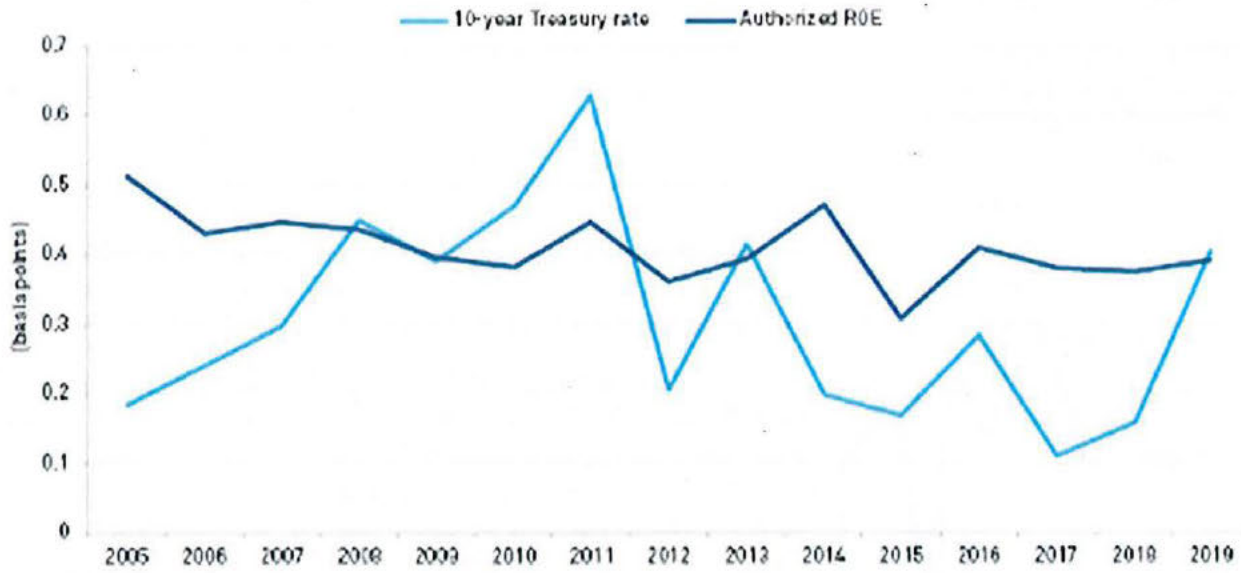


Data compiled as of June 15, 2020
Population sample includes all gas and electric rate cases where an ROE was determined.
Excludes limited issue rider proceedings and Alaska rate cases because the authorized ROE was an outlier from the sample.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

RRA tracks trends in industry ROE averages and compares commission-authorized ROEs to the industry average in the time period it was established. In some cases, authorized ROEs have been significantly above or below prevailing industry averages at the time established. The ROEs authorized by a commission factor into RRA's assessment of the climate in that state for utility investors. For RRA's ranking of states, refer to the recent Quarterly Regulatory Evaluations report.

The **variance** in **authorized ROEs over** the **years** has **remained fairly consistent**, with the **one standard deviation amounting to** a range of roughly **40-50 basis points above and below** the **industry a**verage. **Statistically** speaking, 6**8**% of a **sample population should occur within one standard deviation** of a normal distribution; returns above and below one standard deviation could be viewed more significantly different than the RRA average. **For example**, the **majority** of **ROE authorizations during** a **year when** the **average ROE was 9.5%** would **roughly fall** into the **range** of **9.0%-10.0%.**

Standard deviation of authorized ROEs



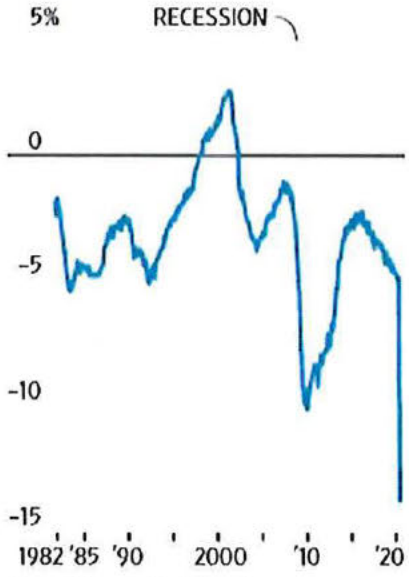
Data compiled as of June 15, 2020.
Data represents one standard deviation from average authorized ROE, Treasury rate by year.
Population sample includes all gas and electric rate cases where an ROE was determined.
Excludes limited issue rider proceedings and Alaska rate cases because the authorized ROE was an outlier from the sample.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

As noted in the chart, however, **authorized ROEs have had considerably less variability over time than** the **10-year Treasury rate**. This could be due to **commissions' preferences for rate stability**.

Deficit Reaches $3 Trillion as Virus Costs Soar

by Kate Davidson – WSJ – Jul. 14, 2020

U.S. budget deficit/surplus over 12-month period as a share of gross domestic product



Source: Treasury Department

Deficit share of **GDP rises to** a **post-WWII record**, with any **new stimulus** plan **likely to widen gap**.

The **U.S. budget deficit reached $3 trillion** in the **12 months through June** as **stimulus spending soared** and **tax revenue plunged**, putting the federal government **on pace** to register the **largest annual deficit as** a **share of** the **economy since World War II.**

As a share of gross domestic product, the 12-month deficit came to 14% last month, compared with 10.1% in February 2010, when the U.S. was still recovering from the last recession. In **June alone**, the **deficit widened** to a **monthly record** of **$864 billion**, the Treasury Department said Monday – nearly as much as the gap for the **entire previous fiscal** year, which **totaled $984 billion**.

The **Congressional Budget Office** has **projected** the **annual deficit** could total **$3.7 trillion** in the **fiscal year** that **ends Sept. 30. But** the **gap could widen** even further **if Congress** and the **White House agree** this month on **another round of emergency spending**, which economists have argued is vital to keep households and businesses afloat until the economy begins to recover.

Congress has **authorized $3.3 trillion** in **new spending since March** to help combat the impact of coronavirus shutdowns, including stimulus checks to U.S. households and emergency loans and grants to struggling businesses and state and local governments. The Trump administration has also **delayed personal and corporate income-tax payments until July 15** in an effort to keep more cash in people's wallets.

"The good news is this means we're getting fiscal relief out the door fast," said Maya MacGuineas, the president of the Committee for a Responsible Federal Budget, a deficit watchdog group. "The bad news is that we're **having** to **borrow record amounts on top of** so much unpaid-for spending and **tax cuts** that lawmakers approved in the past few years."

Widespread unemployment and business shutdowns have **pushed down tax revenue while** also **boosting spending** on **safety-net measures** including **unemployment insurance and nutrition assistance**.

A **renewed surge** of **corona-virus cases** across the **South and West** is forcing **some states**, including Texas, to **re-impose social-distancing measures**, **putting** a **quick economic recovery in doubt**.

Federal deficits typically **widen in** times of **recession** and **narrow when** the **economy grows**. This time, the deficit was already rising in the final years of the decade-long expansion that ended in February following the Trump administration's sponsored tax cuts of 2017.

Political support for taming deficits has faded in Washington in recent years, as persistent global demand for U.S. Treasury assets has kept borrowing costs near historic lows. **Despite** the **surge** in **government borrowing**, **net interest costs fell 11%** in the **first nine months** of the **fiscal year**, the Treasury said on Monday.

The rise in red ink has rankled some Republicans and White House officials, who have argued against another sweeping economic relief package and called instead for aid that is more narrowly-targeted at the hardest-hit industries, in part due to concerns about the deficit.

Democrats and many economists, however, have said policy makers must tackle the more pressing problem – controlling the virus and supporting American households and businesses – and worry about deficits later, especially when the cost to borrow is so low. The **yield** on the **benchmark 10-year Treasury note** was around **0.622%** late **Monday**, **down from more than 2%** a **year ago**.

The **CBO** estimated last week that the **jobless rate** will **end** the **year at 10.5%, compared** with a **50-year low of** about **3.5% before** the **recession**. While the **economy** is expected to grow in the second half this year, **output** in the **fourth quarter** of **2020** will be **5.9% lower than** a year earlier, the agency said.

The economy showed signs of reviving in May and June as parts of the country reopened. The number of people receiving unemployment benefits fell by nearly 700,000 to 18.1 million for the week ended June 27, the lowest reading since the week ended April 18. Employers added a combined 7.5 million jobs in May and June after shedding 21 million jobs in March and April.

Whether that recent rate of job creation and relatively lower pace of layoffs, can continue is in doubt because coronavirus infections are causing state authorities to reconsider reopening plans and creating renewed uncertainty for many businesses and consumers.

In June, spending soared to $1.1 trillion, compared with $342 billion in the year-earlier period, the Treasury said Monday. Nearly half of that spending went to emergency small-business loans provided under the **P**aycheck **P**rotection **P**rogram, aimed at helping small firms meet payroll and keep workers attached to their jobs.

Outlays for jobless benefits climbed from about $2 billion in June 2019 to $116 billion last month, about half of which was due to the **extra $600 in weekly benefits** that Congress authorized as part of the so-called Cares Act. T hose enhanced payments are set to expire at the end of this month unless Congress chooses to extend them.

Meanwhile, federal revenue sank 28% to $241 billion, due in part to the administration's decision to delay tax payment deadlines. The government typically

receives an influx of revenue in June when corporations and individuals make quarterly estimated tax payments.

Senior Treasury officials said Monday that they expect to receive a large share of that revenue in July although declining wages and reduced economic activity have also constrained the government's receipts.

For the **first nine months** of the **fiscal year**, the **budget gap totaled $2.7 trillion**, the Treasury said, more than **triple** the **deficit** during the **year-earlier period**. **Receipts fell 13%** from **October through June compared** with a **year earlier, and spending rose 49%.**

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Treasury Yields Rise in Volatile Session

by Sebastian Pellejero – WSJ – Jun. 17, 2020

U.S. government-bond yields swung wildly Tuesday amid conflicting signs about the pace of the global economic recovery from the coronavirus pandemic.

The **yield** on the benchmark **10-year Treasury note** rose as high as 0.783% in early trading, before paring its climb to **0.754% at** the **market close**, according to Tradeweb, from 0.701% at Monday's close. **Yields rise when bond prices fall**. The **30-year yield** followed a **similar path**, **finishing** the trading **day** at **1.538%**, from 1.448% Monday.

Yields climbed early in the session **after** the **Commerce Department said** renewed shopping at reopened stores prompted a **record 17.7% increase** in **retail sales** in **May**, though total spending remained below levels prior to the pandemic.

The increase followed three consecutive months of declining retail sales, including the largest monthly drop on record in April, when retail spending fell 14.7% on a revised basis.

Investors welcomed the data as the latest sign that the worst of the economic shock from the coronavirus has passed.

Further buoying their optimism: reports that President **Trump's administration** is preparing a **nearly $1 trillion spending plan** on **infrastructure**.

Yields pared their climb sharply, **however**, after signs of rising coronavirus cases and new warnings from **Fed**eral Reserve **Chair**man Jerome **Powell** about the **economic outlook**.

Mr. **Powell** said Tuesday that the **U.S. economy faces significant long-term damage from higher unemployment** and a **wave of small-business failures**, **despite** **recent** **signs of improvement**.

"If not contained and reversed, the downturn could further widen gaps in economic well-being that the long expansion has made some progress in closing," Mr. Powell said in testimony presented to the Senate Banking Committee on Tuesday.

DOJ Asks for Denial of Utility Settlement

by Timothy Puko – WSJ – Jul. 10, 2020

The **Trump administration** is **asking** a **federal judge** to **reject** a **settlement between** the **Sierra Club** and a **Michigan utility over alleged clean-air violations**, arguing that the deal improperly goes beyond what the federal government has approved.

The **motion**, filed late Wednesday, **asks** a **U.S. district court in Michigan** to **reject** a **settlement** that would **require** Detroit- based utility **DTE Energy** Co. to close **three coal-fired power plants** and **pay $2 million** for local environmental **improvements**.

Those terms would be **in addition** to **a $7.3 million settlement** with the **federal government** and would have ended a decade-long case over alleged Clean Air Act violations at DTE plants.

The **Sierra Club** has been a **coplaintiff alongside** the **U.S. government**, **but** the **Justice** Department **says** it **shouldn't have** the **power** to **push** for **settlement** terms **beyond what** the **government approves**. **Justice Department lawyers** say they are trying to **make this** a **test case**, **leading** to a **national precedent limiting** the **ability** of **citizen groups** to **press for stiffer punishments**.

Shannon Fisk, an attorney for the Earthjustice environmental group who represented the Sierra Club in the case, said the government's action jeopardizes a settlement that took more than two years to negotiate and would benefit Black and poor communities that suffered from the coal-burning plants in their communities. "It's unconscionable," Mr. Fisk said. "This should be an easy win for everyone involved."

A DTE spokesman said the company had no comment on the legal action.

Dominion to Fuel Growth with Clean Energy after Abandoning $8B Pipeline

by Darren Sweeney – S&P Global Market Intelligence – Jul. 6, 2020
Bill Holland and Garrett Hering contributed to this article.

Dominion Energy Chairman, President and CEO Thomas Farrell II speaks to reporters in late July 2018 at the Cove Point LNG liquefaction project in Lusby, Md. Dominion on July 5 announced the sale of a 25% stake in the Cove Point export, import and storage facility as part of a larger **$9.7 billion deal with Berkshire Hathaway Energy**.

Dominion Energy Inc. plans to sharpen its **focus on cleaner energy resources** and its **state-regulated utilities** following separate decisions to abandon the Atlantic Coast natural gas pipeline project and sell its gas transmission and storage assets.

Dominion Chairman, President and CEO Thomas Farrell II told analysts and investors on a July 6 conference call that the company will continue to "**aggressively**" **pursue renewable energy**, **storage**, **nuclear license renewals**, **electric vehicle infrastructure** and **energy efficiency** programs.

Dominion Energy **and Duke** Energy Corp. on **July 5 announced** the **cancellation** of the **604-mile Atlantic Coast natural gas pipeline project** based on ongoing delays from legal and regulatory challenges, as well as increasing cost uncertainty.

The decision came a little more than **two weeks after** the 1.5-Bcf/d pipeline project won a 7-2 **victory** at the **U.S. Supreme Court**. The Supreme Court **reversed** and **remanded** a **ruling by** the **U.S. Appeals Court** for the **4th Circuit** that canceled a **U.S. Forest Service**-issued **permit** that enabled **Atlantic Coast Pipeline LLC**, or **ACP**, to **cross** the **Appalachian Trail and sections of national forest**.

Many analysts, however, remained skeptical that the project would cross the finish line even as Dominion announced earlier in 2020 that it would increase its stake in the $8 billion project as part of a $175 million transaction with Southern Co.

Duke Energy, which owns 47% of ACP, expects a pretax hit to its 2020 earnings of about $2 billion to $2.5 billion as a result of the cancellation of the project, the company said in a July 6 Form 8-K filing. One objective of the pipeline was to carry gas to North Carolina, where Duke's regulated electric utilities have been replacing coal-fired power plants with natural gas-fired resources. Another was to provide fuel for heating demand in North Carolina.

Dominion on July 6 reported it **will recognize** estimated **pretax charges** in the range of **$2.7 billion to $3.2 billion** related to the **ACP Project and** the associated

Supply Header project, mostly in the **second quarter** of **2020**. Separately, subsidiary **Dominion** Energy Gas Holdings LLC said it will recognize estimated **pretax impairment charges** in the **range of $400 million to $500 million** related to the **Supply Header project**, which is expected to be reported in second-quarter 2020 earnings. The proposed Supply Header project would have provided approximately 1.5 million Dth/day of firm transportation service to various customers in connection with the proposed Atlantic Coast Pipeline project.

Dominion's sale of gas transmission, storage assets

Separately on **July 5, Dominion announced** the **sale** of its **natural gas transmission** and **storage business to Berkshire Hathaway Energy** in a deal with an enterprise value of about **$9.7 billion**, **including** the **assumption** of **$5.7 billion** of **existing debt**. The subsidiary of Warren Buffett's **Berkshire** Hathaway Inc. **will acquire 100%** of **Dominion Energy Transmission** Inc., **Questar Pipeline** Co. and **Dominion Energy Carolina Gas Transmission** LLC; and **50% of Iroquois Gas Transmission System LP**.

The **deal also includes** the **sale** of **a 25% of Dominion's operating interest** in the **Cove Point LNG export**, import and storage facility in Maryland. **Dominion** will **retain 50% ownership in Cove Point**, with **Brookfield Asset Management** Inc. **continuing** to **own** the **remaining 25% share**. The **transaction** is **expected** to **close** in the **fourth quarter**. At that time, **Berkshire Hathaway Energy will become** the **operator** of the **Cove Point facility**.

Scotia Capital (USA) Inc. analyst Andrew Weisel said the financial implications to Dominion from the decision to cancel ACP are "overshadowed" by the asset sales.

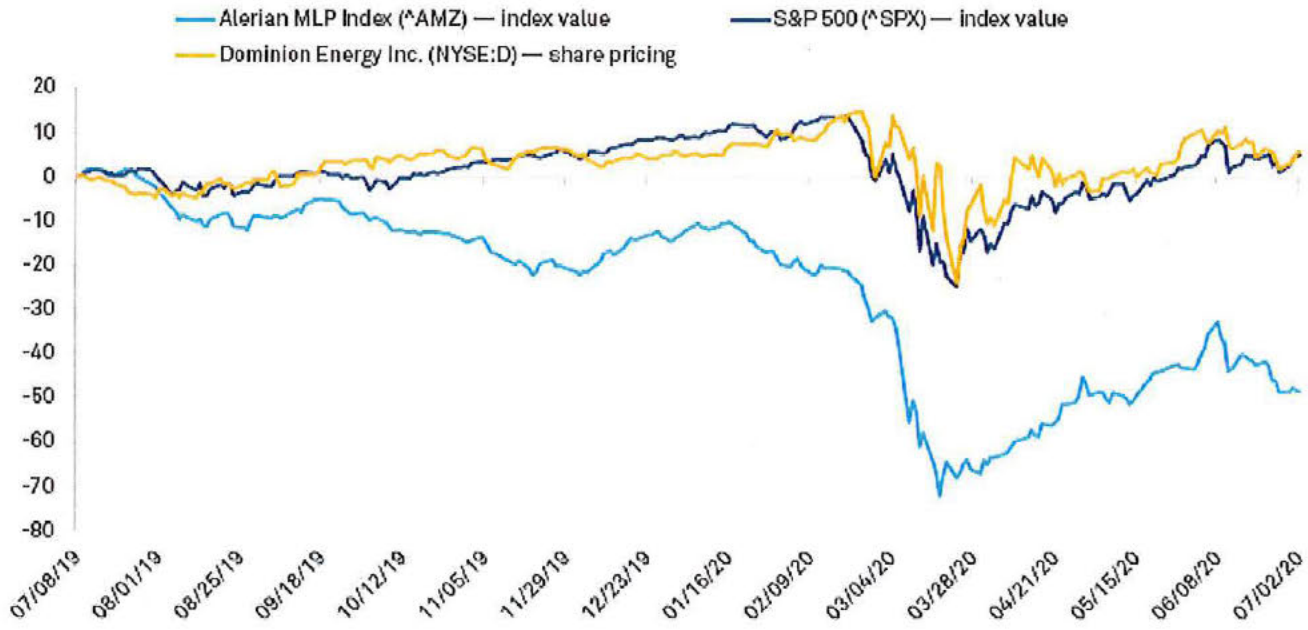
"**By divesting these midstream assets**, the company will **generate 85%-90%** of **consolidated EPS from state-regulated electric and gas utilities**, a materially improved earnings mix and more in line with peers," Weisel wrote in a July 5 research report.

Dominion said it plans to **use proceeds** from the sale of the gas assets to **repurchase about $3 billion in common stock**.

"[T]his sale does highlight the growing pressure on utilities to decarbonize, particularly in a blue state like Virginia and with President Trump trailing Joe Biden in the polls by double digits," Height Securities LLC analyst Josh Price wrote in a July 6 report.

Dominion has **said** it **will shut down coal plants** and **ramp up investments** in **renewables to hit** its **net-zero emissions target** for both its power generation and natural gas operations.

Pipeline stocks lag the broader market
Percent change YTD



As of July 2, 2020, market close.
Source: S&P Global Market Intelligence

The financial picture

To reflect the ACP cancellation and sale of its gas assets, Dominion revised its 2020 operating earnings guidance to $3.37 per share to $3.63 per share. The company's previous guidance was $4.25 per share to $4.60 per share.

Dominion said the EPS impact from ACP was 20 cents per share. Still, the company expects 2021 operating EPS to grow 10% to 11% over 2020 and to grow by about 6.5% annually starting in 2022, off a 2021 base.

The company also said it expects to **target** an approximately **65% dividend payout ratio effective** upon completion of the gas transaction, which implies a 2021 dividend payment of about $2.50 per share. **Beginning in 2022, Dominion said it expects annual dividend-per-share increases of about 6% per year**.

"**We don't take** a **reduction** of the **dividend lightly** by any means," Dominion Executive Vice President, CFO and Treasurer James Chapman said in response to an analyst's question. "It's **not really** a **permanent reduction**. It's a pause, if you will. And in seven years, we're back to where we are today."

Dominion's stock closed down 11% at $73.59 on July 6, on 7x **average volume.**

"We admit we're surprised by the magnitude of the negative stock reaction ... though the stock has been quite crowded, the sale multiple was light, and the **dividend cut** will **hurt income investors**," Weisel wrote in a July 6 report. "Still, we view the transformation positively."

Still growing

Farrell said Dominion still sees "plenty of growth opportunities" with its remaining LDC and renewable natural gas businesses.

"But transforming our electric companies to **more renewable energy**, **more robust grid** protections ... that's also obviously a **very large opportunity** for us," the CEO said. "That's **where** we will be **concentrating** our **capital investments** over the next at least decade. It's **tens and tens and tens and tens of billions of dollars over the next decade**."

Dominion has **outlined** up to **$55 billion in growth capital** between 2020 and 2035 supportive of its **net-zero emissions plan**.

Dominion subsidiary Dominion Energy Virginia, known legally as Virginia Electric and Power Co., on May 1 unveiled plans to **add** about **5,100 MW** of **offshore wind**, nearly **16,000 MW of solar** and about **2,700 MW** of **energy storage** to its portfolio through the end of 2035.

The plan aligns with the Virginia Clean Economy Act state legislation that took effect July 1 and requires Dominion Energy Virginia to procure 100% of its electricity from renewable resources by 2045.

Overall, Dominion serves about 7 million regulated electricity and natural gas customers in eight states.

'Beginning of a new era'

Environmental groups, communities and landowners who staged a six-year grassroots campaign against the Atlantic Coast Pipeline applauded the project's cancellation.

The abandonment of the project is "a recognition that investments in new massive fossil fuel infrastructure are a bad bet," Kelly Martin, director of the Sierra Club's Beyond Dirty Fuels initiative, said during a July 6 media briefing. The decision also represents "the beginning of a new era" for clean energy investments, jobs and environmental justice in the region, where many farmers and communities would have suffered from the pipeline project, she said.

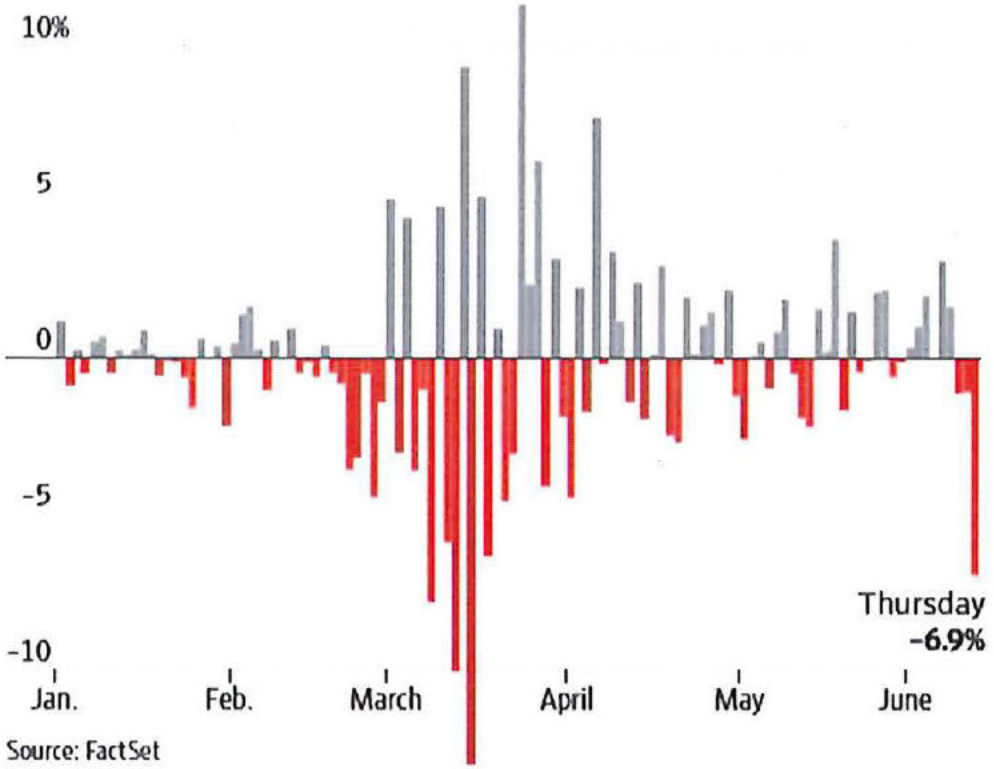
"The Atlantic Coast Pipeline is an anvil that would have stopped and slowed down the transition to renewable energy for decades," added Greg Buppert, a senior attorney at the Southern Environmental Law Center. "Now the deck is cleared and Virginia and North Carolina can move forward to a clean, renewable energy future and people all along the route can rest."

Dow Falls 1,800 on Virus Worries

by Akane Otani and Caitlin Ostroff – WSJ – Jun. 12, 2020
Xie Yu contributed to this article.

Investors seek safety, sending stocks to worst day in months; 'It was a wake-up call'

Dow Jones Industrial Average daily moves



Growing fears of a **surge in coronavirus** infections **sent** the **stock market falling** Thursday, pulling the Dow Jones Industrial Average down more than 1,800 points, or 6.9%, for its worst day since March.

For months, investors have been betting the U.S. and other countries will be able to reopen their economies without seeing an increase in coronavirus cases that might force them to backtrack. Stocks have risen, with the S&P 500 turning positive for the year as recently as Monday.

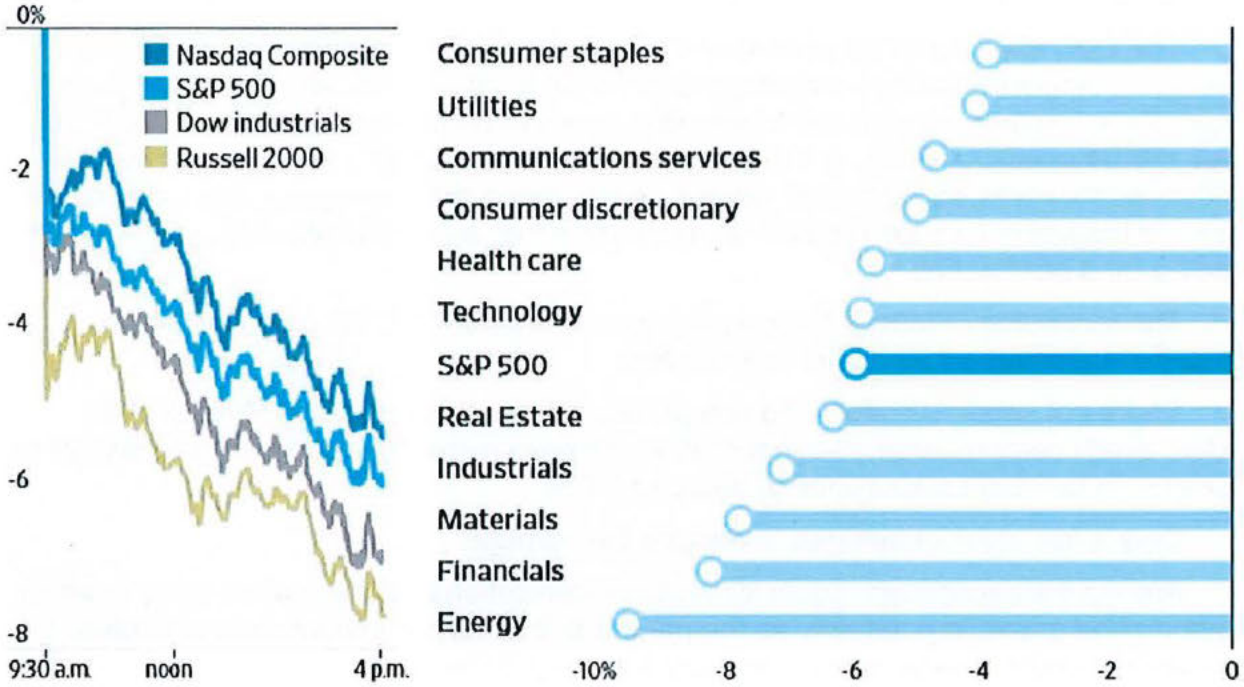
But in the past few days, **investors** have gotten more signs that the smooth reopening they have been hoping for might be increasingly difficult to achieve – throwing into doubt their hopes for a nascent economic recovery. It was a **wake-up call**," said Art Hogan, chief market strategist at National Securities, of Thursday's pullback.

Shares of **banks** and **manufacturers** were **among** the **hardest** hit.

Bank of America dropped 10%, while heavy-machinery maker Caterpillar fell 8.2% and aerospace giant Boeing slumped 16%.

U.S. coronavirus cases have topped two million, with the death toll climbing past 113,000, according to data compiled by Johns Hopkins University. States including **Florida**, **California**, **Arizona** and **Texas** are **seeing increases** in **corona-virus cases after lifting** restrictions put in place to limit the virus's spread.

Index and sectors' performance, Thursday



*S&P 500
Source FactSet

Adding to investors' worries, **top officials increasingly say** the **economy's recovery** from the **recession** will be **slow** and **uneven**.

"The news is getting better, but it's still really bad…it doesn't take much for the market to reset," Mr. Hogan said.

Federal Reserve **Chair**man Jerome **Powell warned Wednesday** that the **labor market could take years** to **recover** from the **pandemic** and millions of people might be unable to return to their old jobs or industries.

That is despite Labor Department data last week showing the economy managed to add 2.5 million jobs in May, a surprising report that had sparked some optimism on Wall Street about an economic snapback.

On Thursday, data showed 1.5 million people in the U.S. applied for unemployment benefits in the week through June 6, extending a drop from a recent peak of nearly seven million applicants in the week through March 28.

Although some economic data appear to offer signs of hope, Mr. Powell's message underscored that "we're in this for the long haul," said Altaf Kassam, head of investment strategy for State Street Global Advisors in Europe.

In the initial stages of the pandemic, many investors and analysts had been predicting the economy would see a "Vshaped" recovery unfold: a relatively short period of declining economic activity, followed by a bounce back to prior levels of growth and spending.

Mr. Kassam, among others, said he believes that isn't likely to happen anymore. "We're not going to recover quickly, and there will be pain ahead," he said.

The Dow shed 1,861.82 points, or 6.9%, to 25128.17. That marked the blue-chip average's biggest one-day percentage decline since mid-March, when growing fears about the coronavirus pandemic triggered a series of punishing selloffs. The **S&P 500 lost** 188.04 points, or **5.9%,** to 3002.10, **dragged lower by all 11 sectors**. The scale of the declines was so big that at various points during the trading day, the index came close to triggering a circuit breaker: a mechanism that automatically halts all stock trading for a brief period.

The technology-focused Nasdaq Composite declined 527.62 points, or 5.3%, to 9492.73, snapping a four-day streak of gains.

Shares of small, U.S.-focused companies slumped as well. The Russell 2000 index, which comprises small-capitalization companies that tend to be more sensitive to changes in the domestic economy, dropped 7.6%.

Only a few stocks managed to escape the carnage.

Among the exceptions: Zoom Video Communications, whose online video chatting platform has grown in popularity as the pandemic has forced schools and workplaces to operate remotely. Shares of the company ticked up 0.5%.

The **Cboe Volatility Index**, also known as Wall Street's "fear gauge," **surged 48%** to 40.79, marking its biggest one-day increase in more than two years. The **VIX** tracks traders' expectations for swings in the stock market and tends to rise as stocks fall.

Meanwhile, worries about the growing number of corona-virus cases pulled stocks around the world lower, too.

The pan-continental Stoxx Europe 600 dropped 4.1%, hit particularly hard by losses among shares of banks, oil-and-gas companies and auto makers.

Yields on European government bonds fell as euro-zone finance ministers met to discuss a proposed rescue package to fund the region's recovery. Investors' expectations for the size and scope of the aid package have dimmed as some European Union members have pushed back against an ambitious plan recently floated by the European Commission.

Markets aren't pricing in the likely disagreement that the proposal will face from some member nations, said James Athey, senior investment manager at Aberdeen Standard Investments.

In the Asia-Pacific region, Hong Kong's Hang Seng Index fell 2.3%. Japan's Nikkei Stock Average lost 2.8%, logging its biggest one-day decline since the start of May, and Australia's S& P/ASX 200 fell 3.1%.

At midday Friday in Tokyo, the Nikkei was down a further 1.5%, the Hang Seng was down 1% and the Australian benchmark was down 1.7%. But U.S. stock futures were up about 1%.

Some investors warned that even if the U.S. doesn't impose as broad a lockdown as it initially did after the coronavirus pandemic hit, regional measures to curtail the spread of the virus will weigh on the economy's recovery.

"There are some areas that are looking concerning, and that is one of the things that is going to get the market's attention," said Hani Redha, a multiasset portfolio manager at PineBridge Investments.

As stocks retreated, traders turned to gold and government bonds, which tend to do well during volatile pullbacks. Gold for June delivery climbed 1.1% to $1,732.00 a troy ounce.

U.S. government bond prices rose, with the yield on the benchmark 10-year Treasury note falling to 0.651% from 0.744% Wednesday. Yields fall as bond prices rise.

ECB Helps Close Gap on Bond Risk Levels

by Anna Hirtenstein – WSJ – Jul. 9, 2020
Pat Minczeski contributed to this article.

Despite European **C**entral **B**ank **President Christine Lagarde's statement** earlier this year that it **isn't** the **central bank's job** to **close spreads**, **that is precisely what it has done**.

The **cost of borrowing** for **Europe's riskiest governments** has **returned** to pre-**coronavirus levels**, indicating that the **central bank** has **effectively created** a **backstop** to the **monetary union's debt market**.

The **spread**, or **difference between yields**, on **Greek** and **Italian government bonds compared** with **German bonds** Wednesday hovered near the **tightest level since before panic** about the coronavirus overtook markets. The **difference between** the **yields** on **euro-zone countries' bonds** is seen as a **barometer** of **financial stress** in the **region**. The wider the spread, the more worried investors are.

The yield on **Greece's 10-year debt** was at **1.029%** and **Italy's** at **1.205%**, on Wednesday according to Tradeweb, the lowest since March and below where they began the year. For both, that is over a **full percentage point less than** at the **height** of the **turmoil**. **Bond prices rise as yields fall**.

"If you know that the ECB is there to protect the spread market, why would you want to bet against it?" said Peter Schaffrik, a global macro strategist at RBC Capital Markets. The central bank "has made huge contributions to stability in financial markets. The **market** is **reassured**."

This is despite historic contractions in European countries' economies resulting from the lockdowns and a surge in debt issuance as governments seek to fund their fiscal stimulus programs.

Italy was the first country in the region to implement a lockdown in early March and subsequently its **economy** is expected to be the worst hit in the trade bloc in 2020. The European Commission is forecasting that it will **shrink 11.2%**. **Greece** is predicted to contract by **9%**, compared with an expected **decline** of **8.7% across** the **euro area**.

Ms. Lagarde said on March 12 that the ECB was "not here to close spreads." After a sharp selloff in southern European government debt, she **quickly pivoted to echo** the **rhetoric** of her **predecessor**. **Mario Draghi**, **pledging** to **do** "**everything necessary**" to **help** the **euro-zone through** the **crisis**. Six days later, the **ECB** announced a €750 billion ($846.84 billion) **bond-buying program**, which was **expanded** to **€1.35 trillion June 4**.

This program is expected to vacuum up net issuance of government debt through to next year, according to research from J.P. Morgan Asset Management.

Also providing reassurance to investors is the **European Recovery Fund**, a **€750 billion plan** put forward by the **European Commission** which is **backed** by heavyweights **Germany** and **France**. It proposes to **provide capital** to **EU countries through** a **mix** of **grants** and **loans**.

In the **U.S., yields** on benchmark **10-year Treasury** notes rose to **0.656%** from 0.648% on Tuesday.

–

Economists Declare US Recession after 128-Month Expansion Ended in February

by Emmanuel Louis Bacani – Jun. 8m, 2020

U.S. economic activity peaked in **February**, defining the beginning point of a recession as the coronavirus outbreak halted the **longest expansion on record**, the **National Bureau of Economic Research declared.**

The National Bureau of Economic Research, or **NBER**, **generally** considered the **arbiter** of **U.S. expansions and recessions**, said indicators of domestic employment and production reached a clear peak in February, including the payroll employment measure and monthly real personal consumption expenditures. A **peak of economic activity marks** the **start** of a **recession**, **while** a **trough**, or an **economy hitting** a **bottom**, **indicates** its **end**.

In particular, the **employment** measure from the **Bureau of Labor Statistics** household survey **plateaued** from December 2019 through **February 2020**, **before dropping steeply** in the following month, the NBER said.

The declaration of a recession, which represents a significant and broad-based decline in economic activity, put an end to the U.S. economy's 128-month economic expansion that started in June 2009, according to the NBER. That surpasses the previous record expansion of 120 months that concluded in March 2001.

The **U.S. economy** **contracted** at an **annual rate** of **5%** in the **first quarter** as the coronavirus pandemic and lockdown measures imposed to control the outbreak disrupted business operations, trade flows and supply chains.

The **Labor Department** reported June 5 that **nonfarm payroll employment unexpectedly rose 2.5 million** in **May** as the country began resuming economic activity. The economy recorded **job losses** of **20.7 million** and **1.4 million** in **April** and **March**, **respectively**.

Unemployment claims totaled more than **42.6 million** over the **11 weeks** that **ended May 30**.

Emerging-Market Green Bonds Are In Demand. What That Means for Investors.

by Craig Mellow – Barron's – Jul. 2, 2020
https://www.barrons.com/articles/emerging-market-green-bonds-are-in-demand-what-that-means-for-investors-51593685800

Debates in the U.S. over climate change may grab more headlines, but Earth's future rests largely with developing countries, as China, India, and other burgeoning economies follow a green or brown paradigm. Fixed-income investors can influence the outcome, maybe, through the fast-growing market in emerging-market green bonds.

This asset class is still relatively microscopic, with less than $200 billion in total issuance. But it did expand by a quarter last year, according to data from Amundi and the International Finance Corp. That is enough for critical mass, says Michael Bolliger, chief investment officer for emerging markets at UBS Global Wealth Management.

"It is growing rapidly and spreading across countries," he says. Chinese issuers dominate the nascent market. But half a dozen nations from Russia to Ecuador launched debut green bonds in 2019, Bolliger adds.

Or not nations, actually. The emerging-market green bond movement is encouragingly driven by private borrowers looking to concrete investments in sustainable energy, cleaner water, more efficient transportation, or smarter buildings.

Sovereigns account for less than 10% of issuance so far, compared with more than half in general bond markets, says Sean Kidney, chief executive of the Climate Bonds

Initiative. That figure excludes state-owned banks like Industrial and Commercial Bank of China, which shattered records with a $3.2 billion green bond last fall.

The emerging-market green bond phenomenon isn't too young to have spawned doctrinal differences. Yerlan Syzdykov, head of global emerging markets at Amundi, focuses on credit issued by banks, which lend to an array of smaller green companies. "Banks can aggregate a dozen projects in the $10 million to $20 million range," he says.

Sandra Carlisle, who manages the Real Economy Green Investment Opportunity fund at HSBC, thinks banking intermediaries are passe. She is looking to invest in corporate credit directly, and spread cash around the globe with a 30% cap on China investments. "Our investors want to have a look-through to where their money is going," she says.

What the two managers have in common is partnership with the IFC, the World Bank's private-sector investment arm. The multilateral vets borrowers for HSBC, reducing the risk of green-washing in its far-flung holdings. With Amundi, the IFC may directly "take up the riskiest tranches so we can price the rest attractively to our institutional investors," Syzdykov says.

Issuers can borrow more cheaply through a green bond than a plain-vanilla vehicle thanks to broader demand, says Kidney of Climate Bonds. The **average savings is between five and 30 basis points** (0.05% to 0.3%). That means investors, already hard-pressed for yield, are accepting less. Green bond enthusiasts claim their instruments can make up the difference as the forward-looking borrowers thrive. But that is just hypothesis so far.

"The Holy Grail is to demonstrate over time that greener firms are less risky and deserve some sort of premium," says Xavier Jordan, chief investment officer for the IFC's financial institutions group.

For now, the main impetus to buy emerging-market green bonds is conscience. But that is enough to keep the asset class growing, the more so as Covid-19 underlines the importance of survivable economics.

"The **bond market is much bigger than the equity market, but** the **ability to deploy capital sustainably is much more limited**," **HSBC's** Carlisle says. "This is **what our investors want us to do**."

Europe Steps Up Stimulus to Stem Crisis

by Tom Fairless – WSJ – Jun. 5, 2020
Harriet Torry and Sarah Chaney contributed to this article.

ECB lifts bond-buying, while trade activity in U.S. sinks, pointing to a long, tough recovery.

The **European Central Bank scaled up** its **bond-buying program** to **€1.35 trillion** ($1.52 trillion) in a bold move that puts its stimulus effort in line with that of the Federal Reserve, while U.S. unemployment and trade data pointed to a rocky recovery from the pandemic shutdowns that crippled the global economy.

Investors cheered Thursday's ECB decision, pushing the euro to its highest level against the dollar since March and fanning a recent rally in euro-zone equity and bond markets. The move eases pressure on the region's embattled governments and underscores a recent shift in Europe, where policy makers initially lagged behind the U.S. in the amount of firepower they threw at the crisis but have over the past week unveiled a series of bold stimulus moves.

"The **euro-area economy** is **experiencing** an **unprecedented contraction**," ECB President Christine Lagarde said. **Economic output** in the region is **likely** to **shrink** by **8.7% this year** before rebounding by 5.2% next year, said Ms. Lagarde, who didn't rule out an even deeper downturn.

That **contraction** is **larger than** what is **expected for the** U.S., where economists surveyed by The Wall Street Journal expect the economy to shrink by 6.6% this year and grow by 5% in 2021.

New data Thursday showed the **ranks** of **people** in the **U.S. drawing on unemployment benefits** ticked up to 21.5 million in the week ended May 23, though the pace **of** increase significantly slowed from earlier in the crisis, the Labor Department said. So-called **continuing claims are released with** a **one-week lag** and **appeared** to **hit** a **peak** in **early May**.

Meanwhile, **U.S. exports and imports both posted** their **largest monthly decreases on record** amid coronavirus-related shutdowns around the world.

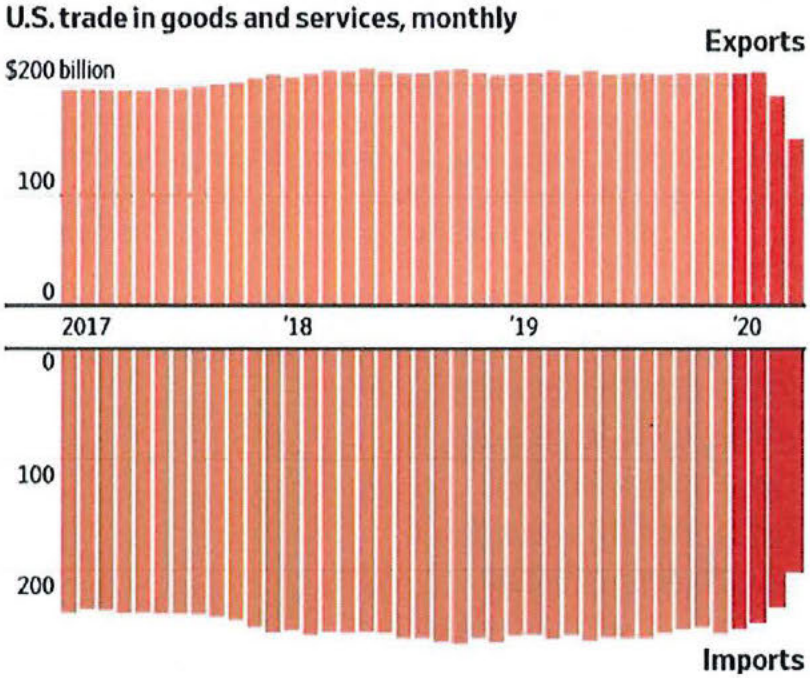
Imports fell 13.7% in April from March, and exports dropped 20.5%, the largest declines since record-keeping began in 1992, the Commerce Department reported on Thursday. The **trade deficit expanded 16.7%** to a seasonally adjusted $49.41 billion.

"Beyond the fact that we're seeing a significant widening of the trade deficit, what really strikes me is the pace at which trade flows are declining," with imports and exports down about a quarter since the coronavirus outbreak, said Gregory Daco, chief U.S. economist at Oxford Economics.

The **Fed**'s rate-setting panel is slated to **release next week** its first set of economic projections since December. New **forecasts could show officials expect** to **hold rates near zero over at least** the **next 2½ years**.

In Europe, the ECB decision pushed the euro 0.3% higher against the dollar to its highest level since mid-March, and yields on Southern European debt fell, as investors saw the expansion as a sign of support for the euro-zone.

U.S. imports and exports have fallen sharply since the coronavirus outbreak.



"The ECB is very well known to be behind the curve, only acting at five minutes to midnight, but now they are ahead of the curve," said Alberto Gallo, a fund manager at Algebris Investments in London. of euro-zone government and corporate debt through

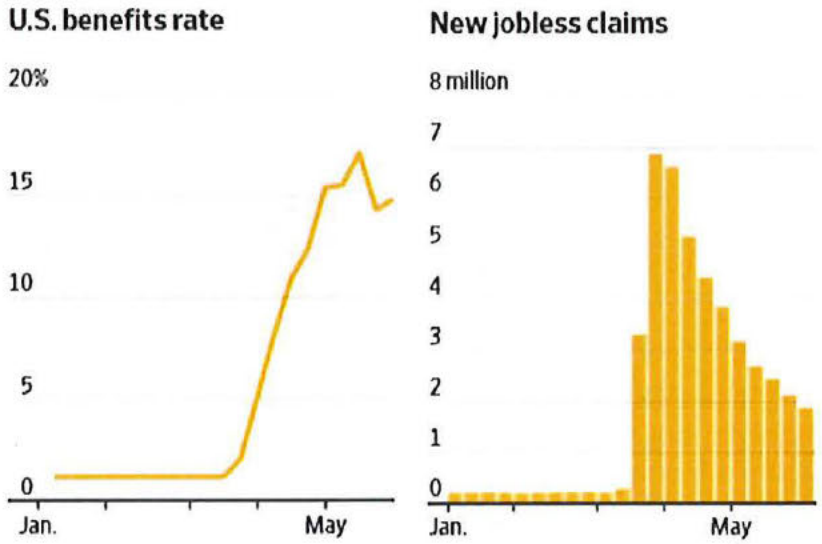
Above: Tugboats escorted the Mediterranean Shipping Co. container ship Maria Elena after it passed under the Verrazzano-Narrows Bridge in New York City on the way to port on May.

June 2021, **expanding and extending an existing €750 billion bond-buying program**. In an unexpected move, the **ECB said** it **would roll over maturing bonds bought under its new bond-buying program through the end of 2022**. The bank left its key interest rate unchanged at minus 0.5%.

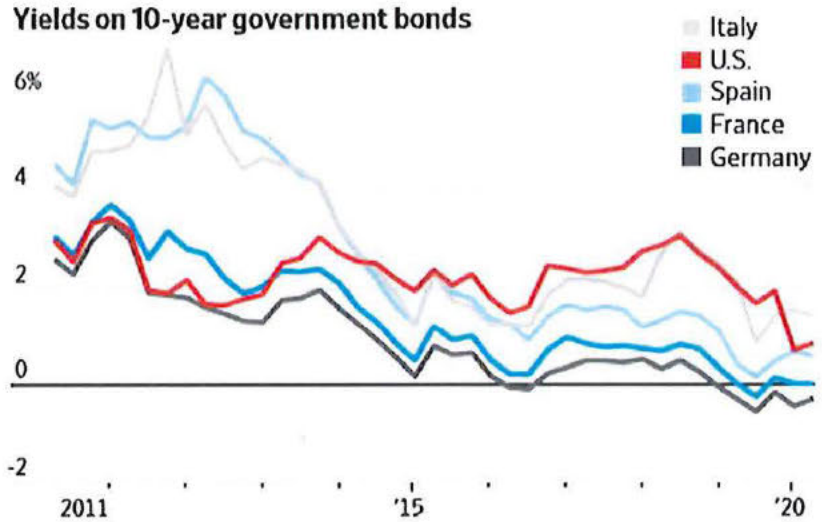
The size and scope of the economic downturn sparked by the coronavirus pandemic have raised concerns that even stronger members won't be spared and pressure on weaker members could be so great as to threaten the currency union itself. Squabbling among member states and tensions within the ECB meant the bloc was slow to react to an economic collapse that could be the worst since World War II.

But recent decisions have been more encouraging. The **European Union set out a $2 trillion coronavirus response plan last week** that, if approved, would mark an unprecedented deepening of the bloc's economic union. Meanwhile, **Germany** unveiled on Wednesday a rare **€130 billion package** of **tax cuts** and **budgetary handouts**, aiming to kick-start consumer and business spending in Europe's largest economy.

Payments to jobless workers are at historic levels as new applications for benefits eased at the end of May.



The U.S. Fed and the European Central Bank have been aggressively buying bonds to help to hold down governments' borrowing costs.



Note: Trade, benefits rate and jobless claims are seasonally adjusted
Sources: Census Bureau (trade); Labor Dept. (benefits, claims); Tullett Prebon (bond yields)

Still, some analysts suggested even those forceful measures might not be enough given the depth of the downturn. The ECB will likely need to scale up its bond purchases by another €500 billion as soon as September if it is to continue buying eurozone debt at its current pace through the middle of next year, said Frederik Ducrozet, an economist with Pictet Wealth Management in Geneva.

The borrowing costs of Italy and other Southern European countries have jumped in recent weeks as investors worried about the ability of highly indebted governments to handle the rising costs of the crisis. The ECB's bond-buying helps keep a lid on those costs.

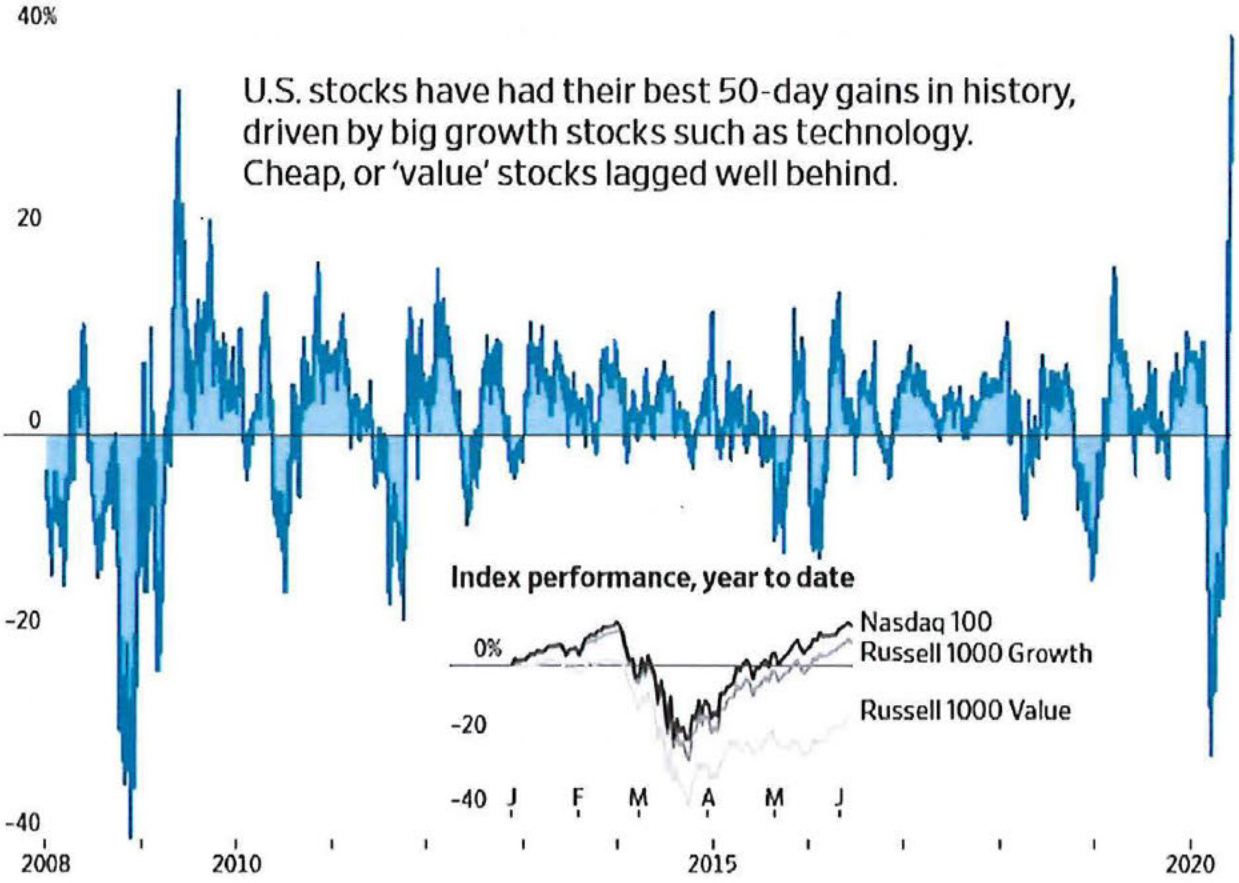
Major central banks such as the **Fed and** the **Bank of Japan** have **pledged** to **buy debt** in **almost unlimited quantities** to **support government spending**. Unlike those central banks, the **ECB** is **legally prohibited from financing governments**.

The **Fed** has **pumped** around **$3 trillion** of **liquidity into** the **U.S. financial system since March**. Accounting for Thursday's expansion by the **ECB** and the more than $1 trillion in cheap loans it is providing across the region, the **two stimulus efforts** are **comparable in scale.**

The ECB's latest move should help to absorb much of the €1 trillion or more of additional debt that euro-zone governments are expected to issue this year as they battle the coronavirus pandemic.

While there are tentative signs the euro-zone's downturn might be bottoming out, the recovery "has so far been tepid compared with the speed at which the indicators plummeted in the preceding two months," Ms. Lagarde warned.

S&P 500, 50-day change



Sources: Refinitiv (S&P 500); FactSet (Nasdaq 100, Russell 1000 indexes)

European Union Sets Out Major Coronavirus Recovery Plan

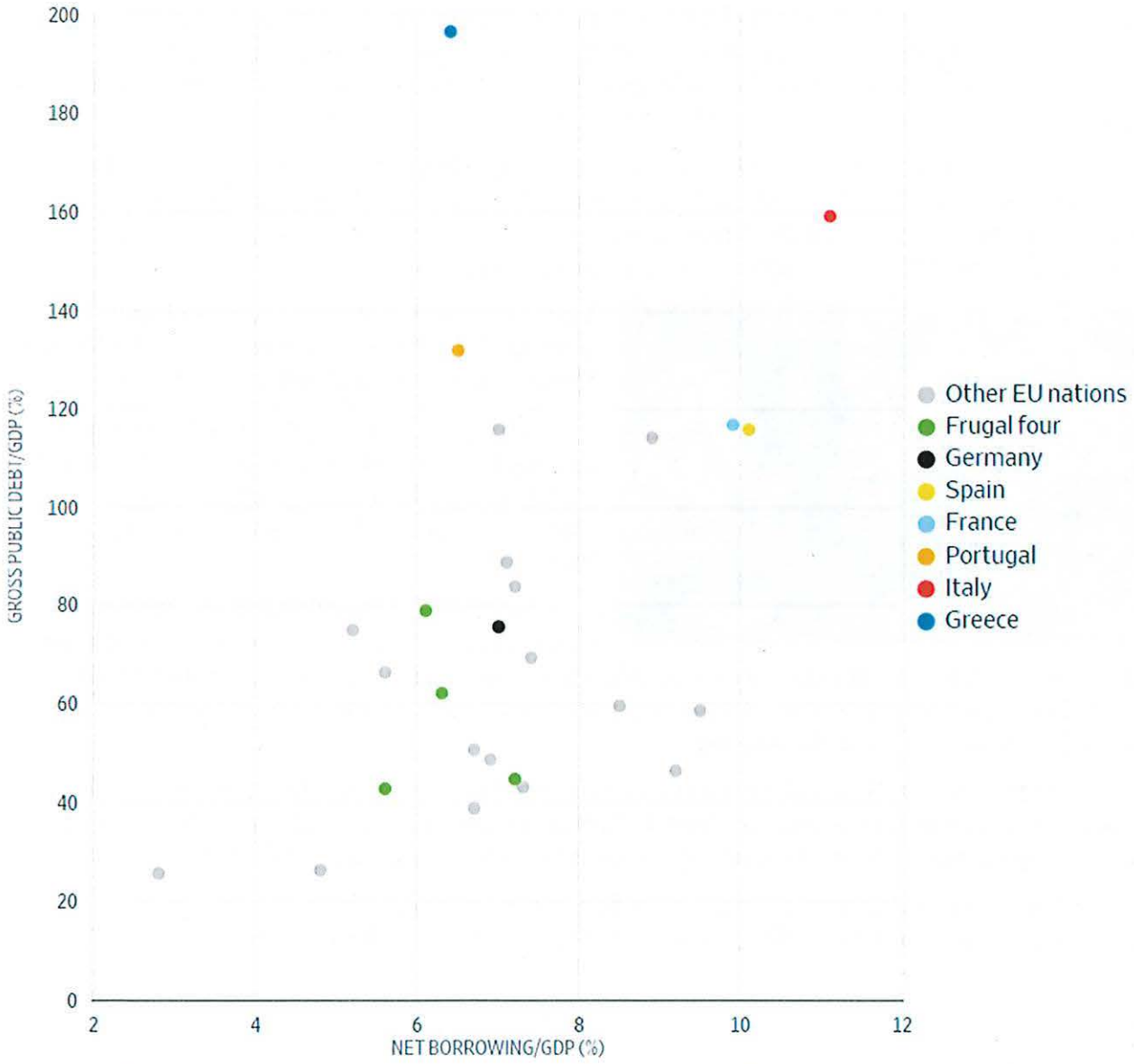
by Laurence Norman – WSJ – May 27, 2020

If implemented, the plan would represent a historic step in knitting together member nations' finances. All EU countries must approve the coronavirus recovery plan.

Double Blow

Some EU countries hit hardest by coronavirus are also its weakest financially.

Debt and Deficit Relative to GDP of European Union Countries
2020 Forecasts



The **European Union** set out a **€750 billion ($824 billion**) **coronavirus recovery plan** and **€1.1 trillion budget proposal** to **lift** the **region from** its **economic slump**, in a move that threatens to intensify the political fights already dividing the bloc.

The proposal from the European Commission, the EU's executive arm, follows a similar Franco-German plan set out last week. It **would allow significant new transfers** of **wealth among members**, funded by €750 billion in commonly issued EU debt for the recovery plan.

The plan aims to quickly provide a massive fiscal injection for the bloc's hardest-hit countries, without increasing the soaring debt levels of southern countries including Italy, Spain and Greece. The new debt would be repaid over several decades, starting only in 2028. Some extra money would start flowing this year, in a move designed to stop companies collapsing and keep public investment flowing.

All EU countries must approve the **plan**, which **includes €500 billion** in **grants** and **€250 billion** in **loans to hard**-hit **members**. While many compromises will be needed, the biggest fights are likely to arise over the split between grants and loans, what strings are attached, and how to win over the EU's poorer new members in its east.

A group of **wealthier northern countries**, including the **Netherlands**, **Denmark**, **Austria** and **Sweden**, have already questioned the plan. **Dubbed** the "**frugal four**," they **want** to **avoid** the political risk of **putting their taxpayers on** the **hook** to **repay EU debt issued** to **fund** major **spending in** the bloc's **south**.

Left: German Chancellor Angela Merkel attended a joint news conference with French President Emmanuel Macron May 18.

The plan, if approved, would respond to demands from the European Central Bank for governments to match its ultra-easy monetary policy with coordinated, large-scale fiscal efforts.

German Chancellor Angela Merkel's backing for a massive recovery plan followed a recent decision by the country's constitutional court raising doubts over the legality of ECB bond-buying programs. Those programs underpinned the EU's recovery from the financial crisis almost a decade ago.

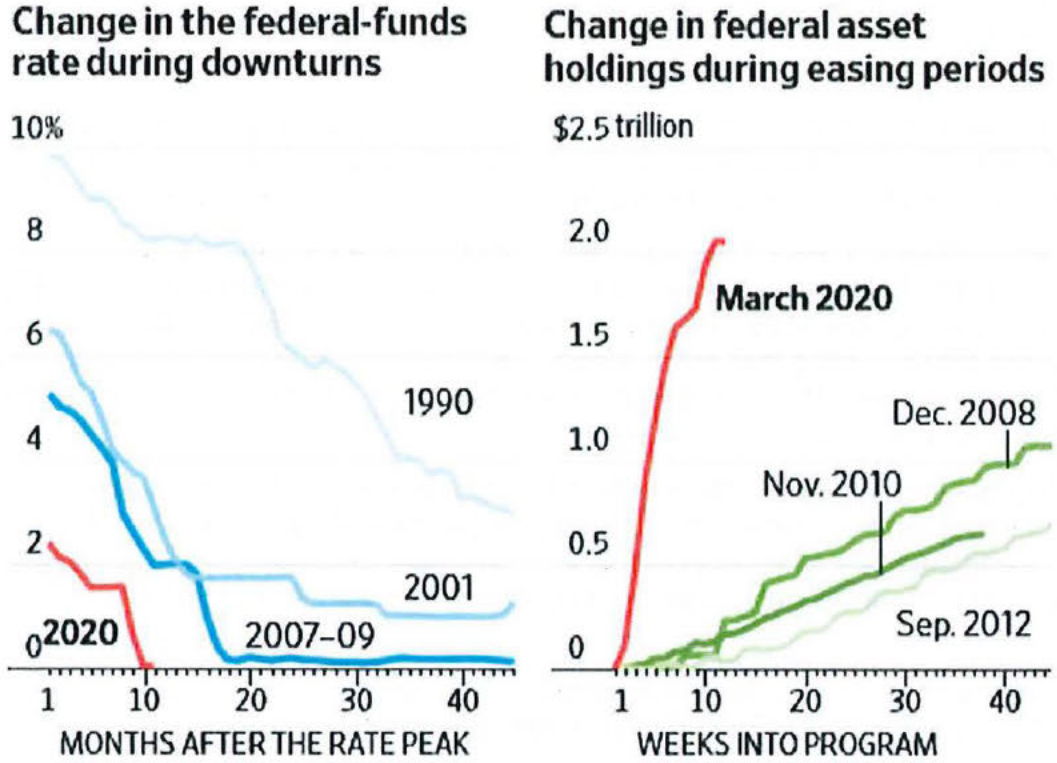
EU officials are braced for weeks of arguments. They hope that national leaders will be able to meet in person in June to find a compromise, though many say further talks may be needed and that an agreement before summer isn't guaranteed.

Unlike many Western nations, **Sweden didn't order** a **strict coronavirus lockdown**. Its **economy still took** a **hit**. Shops and bars didn't shut down.

Fed Aims to Fortify Low-Rate Pledge

by Nick Timiraos – WSJ "The Outlook Column" – Jun. 8, 2020

To stimulate the economy in the past decade with interest rates pinned near zero, the Federal Reserve made promises about how long they would remain low.



Source: Federal Reserve

Now, Fed officials are thinking hard about a new tool that would reinforce such promises by committing to buy Treasury securities in whatever amounts are needed to peg certain yields at low levels. Fed officials aren't prepared to announce any decision on so-called **yield caps** when their two-day policy meeting concludes Wednesday. With **rates near zero** and **unlikely to go lower**, two other policy questions must get resolved first: how to manage their pace of bond purchases and how to communicate their long-run intentions, using so-called forward guidance.

Fed officials believe forward guidance helps stimulate demand after their policy rate is near zero because it sets public expectations about future policy, which influences the rates set by markets.

How they calibrate those two tools could determine whether and how they cap yields, which would function as a hybrid of both. The **Fed hasn't capped yields** on **Treasury securities since 1951**, when it dismantled a stimulus scheme used during World War II.

Fed officials are closely studying the experience of Australia's central bank, which in March set a target of 0.25% for the country's three-year government-bond yield and which has so far managed to keep it there without significant asset buying.

For the U.S., caps might work like this: If the Fed concludes it is likely to hold rates near zero for at least three years, it could amplify this commitment by capping yields on every Treasury security that matures before June 2023.

While some officials don't think caps are needed now because investors don't expect the Fed to lift short-term rates for several years, caps could limit any unwelcome jump in Treasury yields due, for example, to a coming surge of government-debt issuance to finance virus-related economic relief.

Reinforcing forward guidance with caps could also push back against the strong pressure to raise rates that officials faced last decade amid fears of an inflation upturn that never materialized, said Fed governor Lael Brainard in a speech last fall.

First, officials will have to design their forward guidance and consider their asset-purchase goals. Forward guidance comes in two flavors: One ties changes in rates to meeting certain economic thresholds, while the other links them to certain calendar dates in the future. In the first case, for example, the Fed could say it won't raise rates until inflation reaches 2% and unemployment falls to 5%. In the second, it could say it will hold rates steady for at least two years.

Tying guidance to economic thresholds might better address the uncertainty surrounding the outlook, while calendar-based guidance provides more certainty to investors and could be more effective at keeping rates low when data turn around decisively, said Roberto Perli, a former Fed economist who is now at Cornerstone Macro.

Yield caps would be a natural complement to the calendar- based guidance but could be trickier to communicate if paired with outcome-based guidance.

Capping yields brings risks. Because investors already expect rates to stay low, the tool may not provide much stimulus unless the Fed were prepared to target longer-dated Treasurys. Prematurely ending the caps, either because of inflation or financial-stability concerns, would damage the Fed's credibility and could lead to a nasty rise in rates. Setting caps at a level investors deem too low could force the Fed to buy massive amounts of securities to defend its peg.

"It's easy going in, but we don't really understand how the exit is actually going to said William Dudley, who was president of the New York Fed from 2009 to 2018.

At this week's meeting, Fed officials are likely to debate how to clarify their asset-purchase plans. The Fed extinguished a financial panic in mid-March by purchasing huge quantities of Treasurys and mortgage bonds after investors dumped long-dated securities in a flight for cash. The Fed has been gradually reducing purchases every week.

Officials have said their purchases, totaling more than $2.2 trillion since mid-March, are designed to restore orderly market function. This rationale is different from their prior open-ended round of asset purchases, called **quantitative easing** or **QE**, conducted between 2012 and 2014, which was designed to stimulate hiring and investment and was more concentrated at longer-dated securities than the current purchases have been.

Finally, officials face questions about when to roll out any policy shift. The economy is facing a cash-flow problem, not just a drop-off in demand, and a potential wave of bankruptcies looms. Because it may take time to safely restore economic activity given the threat of infection, what ails the economy can't be solved solely by boosting demand.

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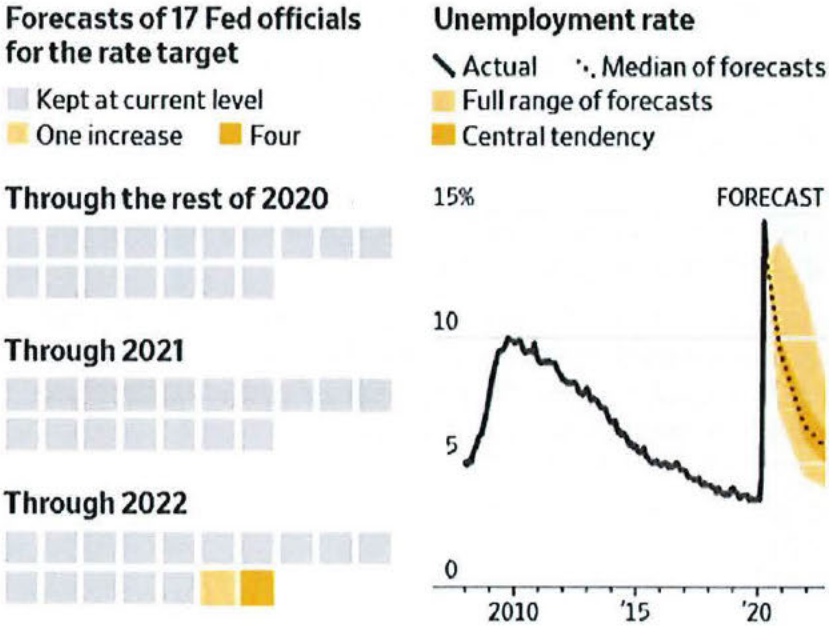
Fed Plans to Keep Rates at Low Level for Years

by Nick Timiraos – WSJ – Jun. 11, 2020

Looking Ahead

Most Federal Reserve officials foresee keeping the interest-rate target at its current level through 2022.



Notes: Number of forecast rate increases are based on a quarter-point change. Unemployment rate is seasonally adjusted. Central tendency excludes the three highest and lowest forecasts.
Sources: Federal Reserve (forecasts) Labor Department (historic unemployment)

Unemployment in **fourth quarter** is **forecast** at about **10%** amid economic damage.

Federal Reserve officials signaled plans to **keep interest rates near zero for years** and said they were studying how to provide more support to a U.S. economy battered by the coronavirus and related shutdowns.

"We are strongly committed to using our tools to do whatever we can and **for as long as it takes** to provide some relief and stability," **Fed Chairman Jerome Powell said Wednesday** at a virtual news conference after a two-day policy meeting.

The commitment from the central-bank chief comes as the virus has forced the nation into a recession, ending the longest economic expansion on record, and sent **unemployment** to post-World War II highs. In projections released Wednesday, most of the 17 Fed officials who participate in the rate-setting meetings see the unemployment rate averaging between 9% and 10% during the last three months of the year. That would be down from **13.3% in May** but still well above the **3.5%** level of **February**.

Stocks were little changed, with the S& P 500 index closing down 17 points, or 0.5%, at 3190.14 after initially rallying following the Fed's statement.

The **10-year Treasury** yield fell 0.1 percentage point to **0.728%.**

In the **new Fed projections**, **all 17 officials** said they **expect rates near zero next year**, and **15** of them projected rates would stay there **through 2022**.

"We're not thinking about raising rates. We're **not even thinking about thinking about raising rates**," Mr. **Powell said**.

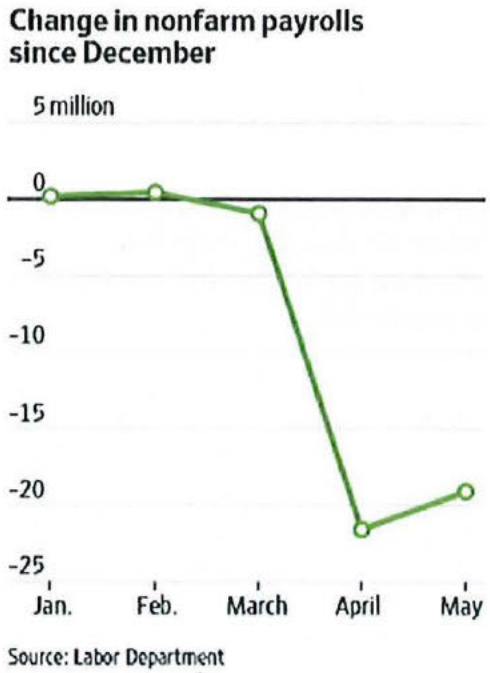
Fed officials projected the **economy would contract** by anywhere **between 4% and 10% this year**. **Projections** for **next year** were **unusually uncertain,** with at least one official projecting an additional 1% contraction while most expected growth of around 5%.

Officials made one policy change Wednesday by saying they would **maintain** their **recent pace** of **purchases of Treasury and mortgage securities**, effectively **ending gradual, weekly reductions**. They **will buy** at **least $80 billion** in **Treasurys and $40 billion in mortgage securities, net of maturing bonds, a month**.

Mr. **Powell** played down the positive news from last week's report that the economy unexpectedly added 2.5 million jobs in May, **highlighting** the **potential long-run damage** the **virus** could **inflict** on the **economy** **by changing consumer and business behavior**.

Last week's report "was a welcome surprise. We hope we get many more like it, but I think we have to be honest, that it's a **long road**," he said.

Even with the gain, there are stil**l nearly 20 million fewer people employed than** there were **in February**, and Mr. Powell said it was possible millions of people wouldn't go back to their old job or their prior industry, given the potential for **reduced demand** for **goods** or **services that require** increased **human contact**.



"It could be some years before we get back to those people finding jobs," he said.

Mr. Powell lauded the response from officials in Congress and the Trump administration who approved around $3 trillion in various emergency-spending measures. But he again suggested more could be needed as the scale of long-term damage became clear.

"We're doing a fair job of getting through these first few months, more than a fair job. The question, though, is that group of people who won't be able to go back to work quickly – what about them?" he said.

House Democrats passed last month a further $3 trillion aid bill, but Senate Republicans and the Trump administration have said they want to take more time to evaluate which parts of the economy might need more help.

The **central bank cut interest rates** to **near zero in March** amid the pandemic, and officials have raced to put in place a series of programs to lend to businesses, cities and states. In addition, the **Fed** has **purchased more than $2 trillion in Treasury and mortgage securities since** the **pandemic** **sparked** a **massive** **flight** for **safe**, **cash-like assets in mid-March**.

The Fed entered this week's meeting facing some pressure from markets to clarify the purchases, which it had been reducing every week. The central bank is buying up to $20 billion in Treasurys this week, down from $50 billion six weeks ago, and $375 billion during the week of March 23.

Fed officials have been successful in restoring market functioning, but other factors, such as rising Treasury issuance to finance economic-assistance measures, are threatening to push up long-term yields this summer.

Last Friday's employment report sent the 10-year Treasury yield rising by 0.2 percentage point, to 0.94%, though yields had reversed that rise by Wednesday.

With rates unlikely to go lower, another major element of officials' evolving policy stance will center on how to communicate their long-run intentions, using what is known as **forward guidance**.

Mr. Powell said officials continued discussions about whether to tie their rate plans to certain economic outcomes, such as inflation returning to 2% and unemployment returning to its recent low levels.

Alternate approaches would tie rate changes to specific dates and potentially cap yields on certain Treasury securities by purchasing them as needed to reinforce their rate guidance.

The Fed's actions have buoyed financial markets for now, with stock markets recently returning to positive territory for the year.

But economic crosscurrents have made it hard to diagnose the underlying damage from the virus.

Waiting until September to unfurl any new strategy might give the Fed a better idea of how to calibrate it. By then, they could **know more about any additional economic relief from Congress**, the **prospect for vaccines** and other **information about how** the **virus spreads as commercial activity resumes**.

Fed's Kaplan Sees Slowdown in Recovery as Virus Surges

by Michael S. Derby – WSJ – Jul. 14, 2020

Left: Dallas Fed leader Robert Kaplan

Recent U.S. economic data point to a **slowing recovery** as **cases** of illness related to the **coronavirus pandemic surge across** the **country**, **Fed**eral **Reserve Bank** of **Dallas President Robert Kaplan said** Monday.

"We were hoping for meaningful double-digit growth in the third and fourth quarters, and I think we were seeing it until, say, the second week in June," Mr. Kaplan said during a video appearance. But as things now stand, "I think **growth is slowing**," he added.

Mr. **Kaplan**, who **has a vote** on the rate**-setting Federal Open Market Committee** this year, was addressing **mounting signs** that the **economy's rebound** might be **losing momentum**.

"I think it's **unlikely** we are **going** to go **back to where we were in early April**" when the economy was in severe distress, he said. But he added, "The **issue** is **how fast** are we **going** to **grow out of** this **big decline** we had **in** the **second quarter**, and **unfortunately** with this **resurgence** in **disease**, it's **muting** that **rebound**."

If the health situation gets worse, "that will further mute growth," Mr. Kaplan said.

For now, **Mr. Kaplan still expects** the **U.S. economy** to **shrink 4.5% to 5% for** the **year** as a whole, with **above-trend growth likely next year**.

He also **expects** the **unemployment rate** will likely **fall** from its **current 11.1% to between 9% and 10%** by the **end** of this **year** and to **between 7% and 8%** by the **close of 2021**. The **U.S. started this year** with the **unemployment rate at 3.6%**.

Mr. Kaplan again said the most important thing for getting the economy back on track, standing above anything the Fed or broader federal government can do, is to press a health campaign to mitigate the pandemic. He repeated that wearing masks, which many Americans have been resisting despite medical experts saying it helps limit the spread of the coronavirus, is especially important.

"Individual freedoms are important but there are many things we do in this country, wearing seat belts, not texting when we're driving, many other activities that we are very careful about because we know society will work better, the economy will work better and we'll have more economic growth," he said.

Mr. Kaplan also said the Fed might have to do more to help the economy and it has the capacity to act again if needed; and that the broader government will likely need to extend support for unemployed workers and bolster support for hard-hit local governments.

The central-bank official also defended the Fed's interventions to help private markets, but said that at some point when markets heal more it will be good for the central bank to pull back.

"I am a believer that we will need to get back to more unaided market function without so much intervention from the Fed," he said. "I think it's very important that the market pricing signals accurately reflect the risk, and if you don't have that, you can add distortions which may cause people to take more risks than they should."

Mr. Kaplan also said that financial markets, with an upbeat view of the future, and the performance of the economy, which remains under stress, will eventually converge.

"If you see that kind of disconnect, it doesn't go on indefinitely. Those normally will get reconciled, and this will too," Mr. Kaplan said.

First Father's Day Comes Later for More Men

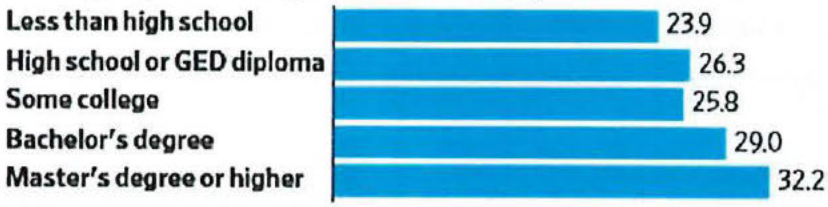
by Jo Craven McGinty – WSJ, The Numbers Column – Jun. 20, 2020

What's the Rush?

The average age for first-time fathers has been increasing. Those who have higher education on average become fathers later compared with the national average.

Average age, upon birth of first child*

Average age of men, by education level, upon birth of first child



*National Survey of Family Growth (NSFG) data for 2006-10 and 2015-17 are weighted to represent the population for the middle year and labeled as such.
Source: National Center for Family & Marriage Research analyses of 1987-88 National Survey of Families and Households and 2002, 2006-10, 2015-17 NSFG

More than 80% of **men** who've never had children say they would like to start a family someday, but in the **past 30 years**, they've **steadily postponed fatherhood**—and the **longer** they **wait**, the **less likely** it is **to happen**.

First-time fathers, **on average**, are now **more than 27 years old** and in total have **fewer than two children**. In the late **1980s**, they were **25** and had **2.1 children**.

"If people want to have kids, but they're not, what does that mean?" said Karen Benjamin Guzzo, acting director of the Center for Family and Demographic Research at Bowling Green State University. "It means something is making it difficult to fulfill their own desire to have a family."

The National Center for Family & Marriage Research, where Dr. Guzzo is an affiliate, analyzed the education, relationship status and average age at fatherhood among men ages 40 to 44 using data from the National Survey of Family Growth.

A potential reason for the delay in fatherhood, researchers found, is what demographers call the "**lengthening transition to adulthood**"—the point at which men (and women) feel as if they've achieved adult status.

"You've finished your education, you've secured a job, you have a stable income and, often, it's when you're married and when you're able to purchase a home," Dr. Guzzo said.

Having kids is the last step.

But some people take five or six years to earn an undergraduate degree, or they extend their education even further by entering a postgraduate program. In the process, they might accumulate a daunting amount of **student-loan debt**, making the other transitional milestones seem financially impossible, at least in the short term.

According to the National Center for Education Statistics, attending a four-year **college now costs** about **five times** as much as it did **30 years ago**. In current dollars,

the average cost of tuition, fees and room and board was **$26,593** for the 2016-17 school year, **compared with $5,504** in 1985-86.

"I think the student-loan debt crisis is one of the big ones affecting people's ability to buy a home, form a relationship and start a family," Dr. Guzzo said. "If you take out a loan for $10,000 or $20,000 or $100,000 or more, you're paying this for a long time."

When the NCES examined data on **students** enrolled in the 2003-04 school year, they found that about **60% had taken out federal loans** to finance their education, and a dozen years later, more than half were still in debt.

Graduates with an associates degree owed a median of $13,800. Those who earned a bachelor's degree owed a median of $11,700. And those who borrowed to attend graduate school owed a median of $48,000.

That kind of burden can be worse for students who start but don't finish college.

"You get neither the employment nor income benefit of going to college," Dr. Guzzo said, "but you do have the debt."

In 2016, the most recent year represented in the data, the **oldest first-time fathers** were **32.3 on average** and had a **master's degree or higher**. Next were those with a bachelor's degree, who were 29.

In terms of relationship status, married men were the oldest first-time fathers, at age 28.3 on average. T hose living with a partner outside of marriage were 24.4. And those who were single were 24.8.

"Compared to women, **men see partnership and marriage as a package deal**," Dr. Guzzo said. "They can't envision being a single dad deliberately, the way women can."

It's possible the Survey of Family Growth, which is conducted by the National Center for Health Statistics, misses some men because it was designed to be nationally representative of women, and, until recently, the age range ended at 44 because it was considered to be near the end of their childbearing years. But men are more likely than women to become parents for the first time when they are older than 44, and the survey might not account for all unmarried first-time fathers.

"We don't have a good sense of how to correct for that," Dr. Guzzo said. "I don't think the numbers are too far off, but demographers definitely worry more about missing men than they do women."

Recent versions of the Survey of Family Growth have expanded the age range to 49 and added an independent sample of men. It's too soon to use the data to analyze long-term trends, Dr. Guzzo said. But it's a baby step forward.

Gas Utility Stocks Reclaim Premium Valuation Over Electrics, Analysis Shows

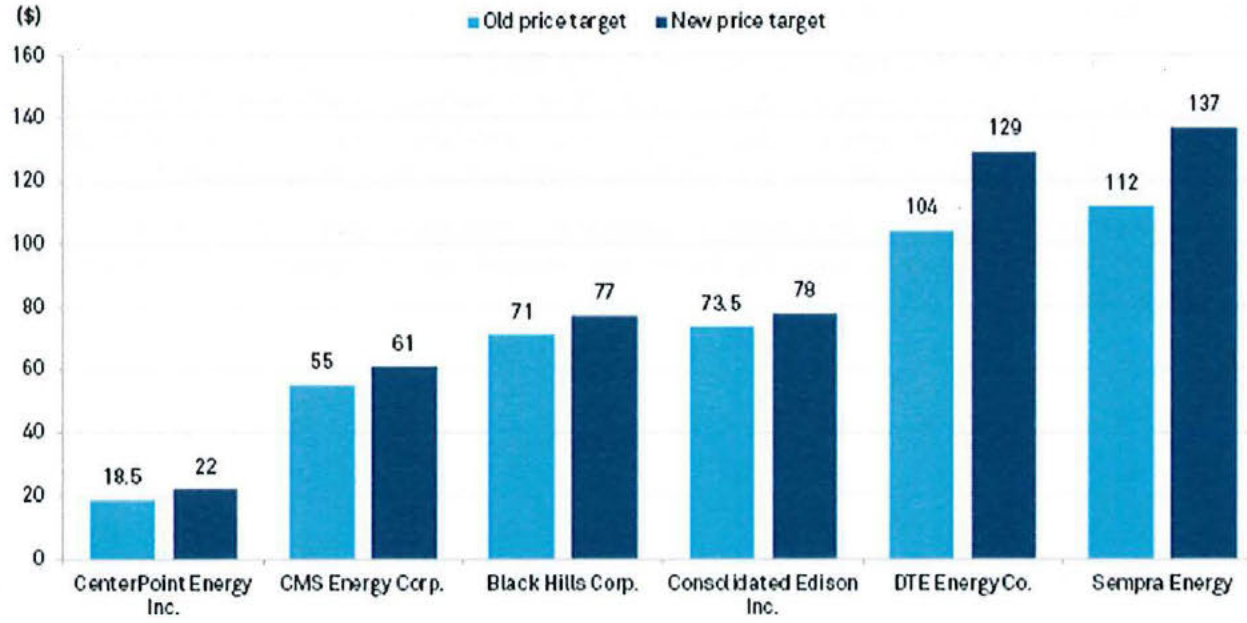
by Tom DiChristopher – S&P Global Market Intelligence – Jun. 9, 2020

Gas utility stocks have **regained** their **premium valuation over electric utility equities** as **fears over restrictions** on **natural gas use** have **given way** to **concerns** tied to the **COVID-19 crisis**, according to Mizuho Securities USA.

Over the last two months, the **price-to-earnings multiple** for **local gas distribution companies** has **flipped from** a **6% discount to** a **4% premium over** the **PE multiple for electric transmission and distribution**, Mizuho analysts said in a June 8 research note. Better rate base growth and **slightly higher return on equity** at **LDCs during** the **economic downturn** will help the stocks maintain or grow that premium, in Mizuho's view.

"Back in the **Great Recession**, **LDC multiples peaked** at a **25% premium** and **averaged** a **10% premium over** a **16-month period**," Mizuho analysts Anthony Crowdell and Paul Fremont wrote. "Should the current economic crisis continue, we could see the LDC premium expand beyond its current 4% premium versus the electric P/E."

Price target revisions for stocks with exposure to improved gas utility PE multiple



As of June 8, 2020.
Source: Mizuho Securities USA

The premium for the LDCs' PE multiple, a measure of future earnings potential, stood at 16% at the **start** of **2019** but eroded throughout the year and into the start of 2020, the Mizuho analysis showed. The rise of **building gas bans** and an **increased focus** on **environmental**, **social** and **governance policies** shook investor confidence in the space, the firm said.

The **current public health and economic crisis** has **changed** the **outlook** for **gas utilities**. The **COVID-19 outbreak** in the **U.S. struck** at the **tail end** of the **winter heating season**, **when LDCs generate most** of their **revenues**, Mizuho noted. **By comparison**, the **economic hangover** could **continue** to **weigh** on **electric power use during** the **peak summer cooling season**, the analysts said.

Multi-**utility executives** have **signaled** that **faltering electricity demand** among **industrial** and **commercial consumers overshadows gas consumption concerns**. **LDCs also use rate decoupling more than electric utilities**, according to Mizuho, meaning their **revenues** are **not as dependent on** their **customers' energy use**.

Stocks that should benefit from the reemergence of the premium include multi-utilities with significant LDC businesses, the analysts said. Those include Black Hills Corp., CenterPoint Energy Inc., DTE Energy Co. and PG&E Corp., which Mizuho rated as "buy," as well as CMS Energy Corp., Sempra Energy and Consolidated Edison Inc., currently rated neutral.

The **companies that saw their PE multiple most improve over electric utilities were pure-play LDCs** such as Atmos Energy Corp., **Northwest Natural** Holding Co., ONE Gas Inc. and Spire Inc. Peers such as New Jersey Resources Corp. and NiSource Inc. with **greater exposure to nonregulated business and electric transmission and distribution**, respectively, have **pulled down** the **average for** the **PE premium**, **Mizuho found**.

Small-cap stocks were **more correlated** to the **LDC premium**, likely **reflecting** their **potential as acquisitions**, Mizuho said. The correlation improved when Mizuho included data from 2015, when Duke Energy Corp. and Southern Co. announced deals to buy Piedmont Natural Gas Co. Inc. and AGL Resources Inc., respectively.

In April, UBS said the stock market downturn could leave gas utilities more dependent on borrowing, leading the Swiss investment bank to remove a bonus it had awarded to LDCs.

GE to Sell Its Lightbulb Business, Shedding Last Link to Consumers

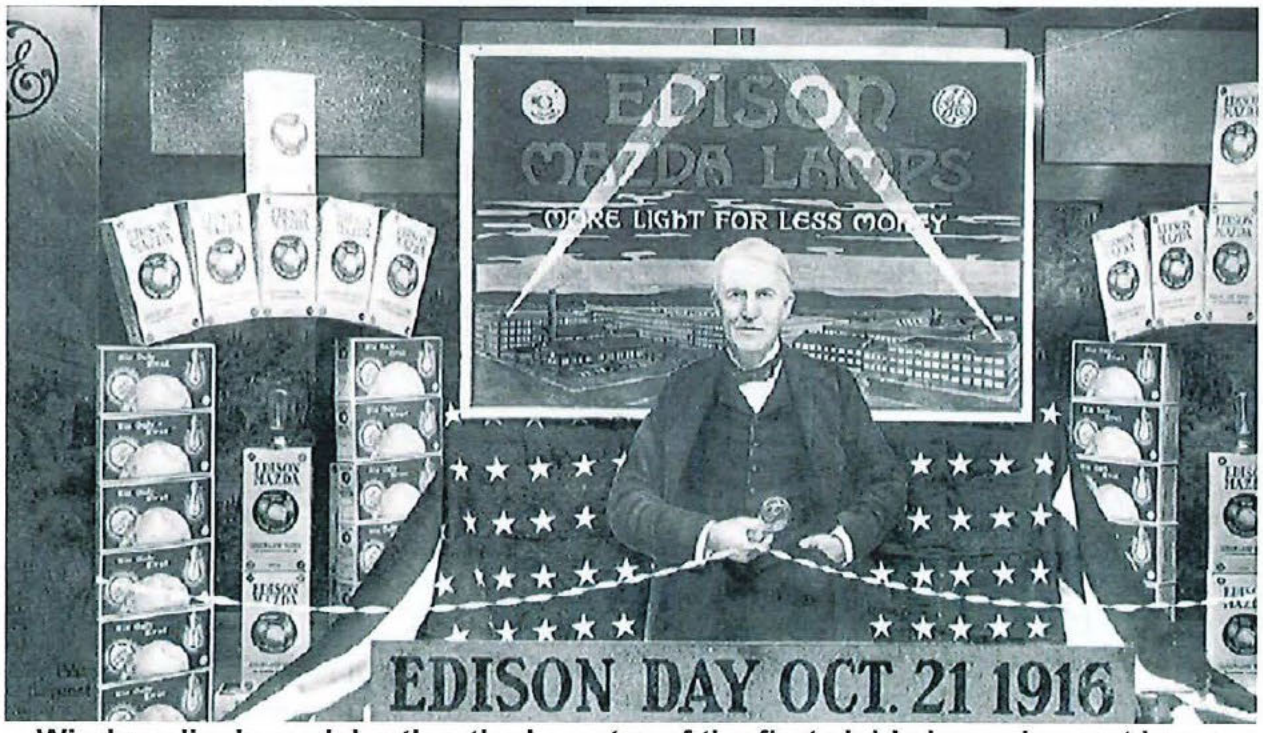
by Thomas Gryta and Cara Lombardo, WSJ – May 28, 2020

General Electric Co. is **getting out** of the **business** of **making lightbulbs**, selling a unit that defined the company for nearly a century and was its **last direct link** to **consumers**.

GE said it would **sell** its lighting business **to Savant Systems** Inc., a seller of home-automation technology. Terms of the deal weren't disclosed, but the transaction valued the unit at **around $250 million**, **including assumed liabilities**, according to a person familiar with the matter. The deal had an **equity value** of **less than $100 million**, this person said.

GE had been looking to sell the business for several years. The conglomerate once made refrigerators and microwaves as well as bulbs but has **exited** those **consumer businesses** as part of a years-long restructuring. It has shifted its focus to making heavy equipment, like power turbines, aircraft engines and hospital machines.

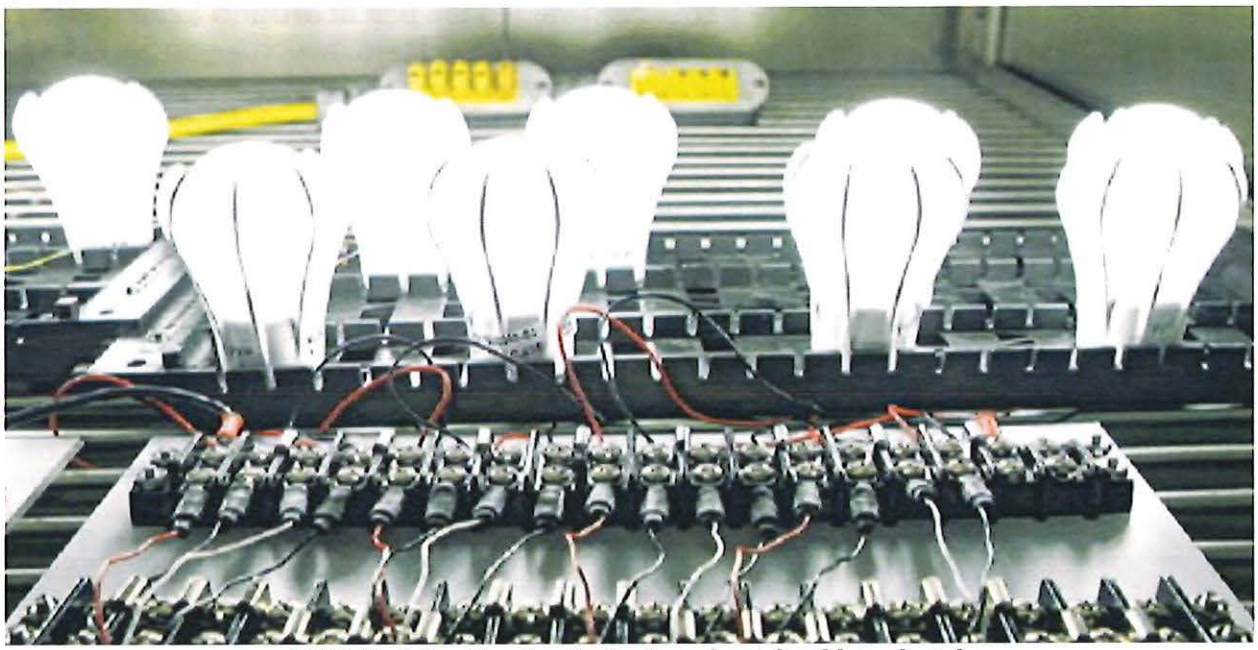
GE Lighting will remain based in Cleveland, and its more than 700 employees will transfer to **Savant**, which **will** also **get** a **long-term license for** the **GE brand**. GE no longer discloses revenue for the lighting business, which it slimmed down over the years.



Window display celebrating the inventor of the first viable incandescent lamp.

The unit traces its roots back to GE's founding **130 years ago** when **Thomas Edison invented** the **first viable incandescent lamp**. In 1935, the first Major League Baseball night game was played under GE lights. **A GE engineer invented** the **LED light** in **1962**.

For decades, **GE's home appliances and lightbulbs** formed a **link** between **American consumers and one** of the **country's oldest** and **largest industrial companies**. The company's popular TV ad campaigns promised to "**Bring good things to life**," **but** the **growth** and **profitability** of the **consumer businesses waned**.



LED lightbulbs tested at a plant in Cleveland.

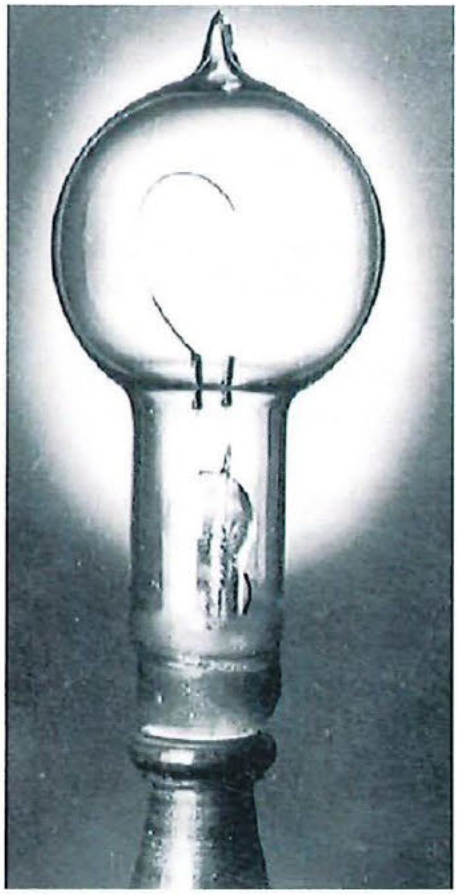
GE got out of making **television sets and small appliances like toasters under** former **C**hief **E**xecutive **O**fficer **Jack Welch**. His **successor**, **Jeff Immelt**, continued the shift, **exiting** the NBC-Universal **media business** and in 2016 **selling** the **large appliances business** to Haier Group. **GE gave** the **Chinese buyer** the **right** to **continue** to **use** its **brand** on **stoves, fridges** and **other appliances for several decades** as part of the deal. Thousands of workers and a sprawling factory complex in Louisville, KY were transferred in that deal.

More recently, the **company** has been **selling off industrial units**—such as its **locomotive**, **oil-equipment** and **biopharma units**. It has used the proceeds to pare down its debts after a plunge in profits at its power and financial-services divisions prompted the **company** to **slash** its **cash dividend to** a **token penny a share** and overhaul its board and executive ranks. It has also **shrunk GE's scope**—leaving the company with about 205,000 employees at the start of 2020.

CEO Larry Culp, who took over in 2018, had **depended on GE's thriving aviation division** in order to turn around the company, **but** the **coronavirus pandemic**

has **crippled** the **airline industry**. GE has cut thousands of jobs in its aviation business and warned that a restructuring of its large power unit could take years.

GE had previously shed its Current business, which sold commercial lighting systems, along with parts of its overseas lighting operations. GE's traditional bulb rivals have also scaled back in the past decade, and many of the buyers have been Chinese companies.



GE spent years trying to sell the lighting business, a largely commoditized and low-margin division, before striking the deal to sell its current business in 2018. The company had spoken to Chinese suitors about the lighting business, but pivoted as the Trump administration increased scrutiny of the security risks of selling to Chinese companies, the person familiar with the matter said.

The transaction is expected to close quickly, possibly within a month, due to it being structured in a way that will limit antitrust clearance required, this person said.

Savant, founded in 2005, is based in **Hyannis**, **Mass**. The company specializes in smart-home systems that control features such as lighting, entertainment, temperature and security settings all in one place.

Robert Madonna, **Savant's founder** and **CEO**, said he plans to maintain Savant as a premium brand and use the GE Lighting business to sell products to the consumer market. GE Lighting already sells smart-home lighting and switches through its "C by GE" branding. "**Lighting** is an **extremely important piece** of the **smart home**," Mr. Madonna said. "And you can do it at a consumer price point."

UBS Group AG was GE's financial adviser.

Global Economy Faces Steep Climb to Recover

by Paul Hannon – WSJ – Jun. 13, 2020

Eun-Young Jeong, Joshua Mitchell, and Gabriele Steinhauser contributed to this article.

Economic numbers coming in from around the world are laying bare a stark truth: **April** was a crippling month.

Coronavirus-driven **lockdowns** implemented in countries world-wide were at their strictest then, and drove a global contraction that has little parallel in history.

The depth of the decline shows the challenges before returning to pre-pandemic levels of activity, given that the damage to business and household incomes is likely to delay a complete recovery.

On Friday, **Britain** – the **world's sixth-largest economy** and one of the few that reports monthly gross domestic product – said **output in April** was down 20% from March and 25% from a year earlier.

Scaled globally, that would be equivalent to a $1.15 trillion loss in output during those 30 days, or roughly the annual output of Indonesia, a country of 270 million people.

"The key point is **we will lose** a **massive amount** of **global output**. It would be illusory to think we can freeze and defreeze the global economy without consequences," said Jérôme Jean Haegeli, Swiss Re's chief economist Officials at the **U.S. Federal Reserve expect** the **national economy** to shrink **between 4% and 10% this year**. Next year, the economy could see anything from 7% growth to a further contraction of around 1%.

A Fed report released Friday said that if virus-related disruptions, such as weak consumer confidence, continued to weigh on economic activity even after lockdowns end, more businesses could fail or scale back their activities. That could mean more temporary layoffs become permanent.

The evidence of the depth of economic pain in April is stark. India recorded no new auto sales in April, according to the Federation of Automobile Dealers Associations. In the U.K., only 197 autos were made, compared with about 70,000 in April 2019.

Exports from Germany, one of the world's manufacturing powerhouses, fell by a third. In Bosnia and Croatia, no steel was produced. Clothing sales in France, the home of fashion, were down 67.4%.

"The shock was huge," said Helene Baudchon, an econo- mist at BNP Paribas in Paris. "Even this word is not enough to qualify the scale. We are back to the 1980s in terms of household consumption of goods."

Americans radically cut spending in April, which forced whole service industries to come to a standstill. The U.S. savings rate soared to 33% – up from 8.2% just two months earlier – with Americans saving $6.15 trillion of their income, Commerce Department data show. Sales of previously owned homes – the bulk of the market – fell

nearly 18% in April from a month earlier, according to the National Association of Realtors. Restaurant reservations made through the website Open-Table fell nearly 100% throughout most of April compared with a year earlier.

The **U.K.**'s Office for National Statistics estimated on Friday that the April lockdown cost the economy £30 billion in lost output ($37.8 billion), and took output back to where it was in 2002. **Eighteen years** of **growth** was **wiped out in** a **single month**.

Friday's figures, along with previous numbers, suggest the **U.K. economy** is on track for its **worst peacetime year since** the **Great Frost of 1709**, when Europe froze for three months, devastating food crops and causing mass starvation.

The collapse in output in April around the world was unprecedented in many ways, not least because it was chosen as a way of saving lives.

"This is the **first recession we knew was coming**," said Chris Williamson, chief business economist at IHS Markit. "It's the **first deliberate recession**."

The enormity of the loss of output in April means many countries will initially enjoy a quick bounce, with double-digit growth in many indicators – creating the illusion of a swift return to normal.

However, the depth of the contraction presages a steep climb back, particularly amid **uncertainty over when or whether a vaccine will arrive**. Economists at Bank of America expect the U.K. economy to grow 9% between April and June. But that would still leave it 18% smaller than before the crisis.

The **Organization** for **Economic Cooperation and Development expects** the **global economy** to **contract by 6% this year**, with **U.S. GDP falling by 7.3%.** If a fresh round of lockdowns can be avoided, it expects the global economy to grow by 5.2% in 2021, leaving it smaller than it was before the pandemic struck. A full recovery would take place only in 2022, or later.

The economic pain associated with draconian lockdowns left few corners of the global economy unharmed.

On April 13, Russian florists gathered in St. Petersburg to destroy some 5 million tulips, chrysanthemums and lilies to draw attention to their plight. In Kenya, workers at the Maridadi flower farm were throwing away a quarter of a million roses a day in early April as Europe's shutdown throttled demand.

"That was the worst time and it hit us hard," said Jack Kneppers, Maridadi's owner.

Uganda, one of Africa's top sugar exporters, which produced 500,000 tons last year, didn't ship a single kilogram of sugar in April, according to data from the country's central bank.

In South Africa, mining production in the key platinum and gold producer plunged by nearly half.

The OECD calculates that a second wave of lockdowns later this year—if the corona-virus were to come roaring back – could cause the global economy to contract even more sharply, by 7.6%. T he expected recovery in 2021 would also be weaker,

with global output expanding by just 2.8%, leaving the economy much further away from a full recovery by year's end.

But it is unlikely the global economy would suffer another April. Governments are learning how to manage the virus, and future restrictions are unlikely to be as broad-based as the initial response.

"Even if we see some containment measures come back, they won't be on the same scale," said Laurence Boone, the OECD's chief economist. "We know more about the virus, and they would be more targeted. The period of confinement would be lighter."

Global Economy Seen Shrinking 5.2%

by Josh Zumbrun – WSJ – Jun. 9, 2020

In the **past 150 years**, the **world** has **suffered only three other episodes** with **recessions** as **sharp as** the one expected amid the **coronavirus pandemic**.

The **global economy** is **expected** to **shrink** by about **5.2% in 2020** as a result of the coronavirus pandemic, making it **one of** the **four most severe downturns** in 150 years, the **World Bank said** Monday.

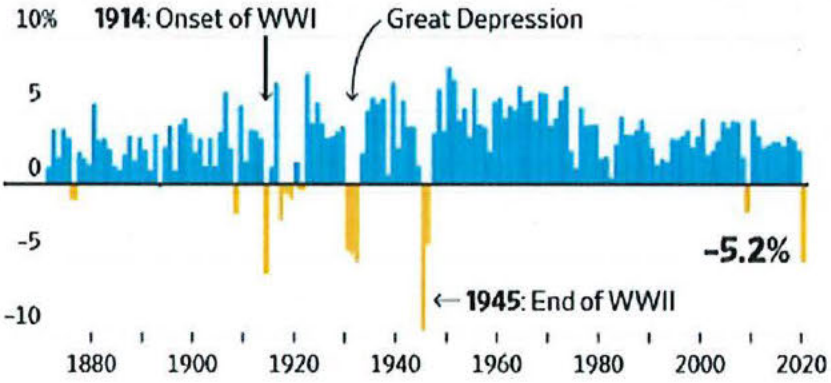
Never before have **so many countries entered** a **recession at once**, **even during** three more severe episodes – the **Great Depression** and the **downturns following** the **two world wars**, the bank said.

The bank's estimate is more pessimistic than the global economic outlook released by the International Monetary Fund in April.

The deeper downturn it forecasts in part reflects the clearer picture of the fallout that has emerged since the IMF's forecast.

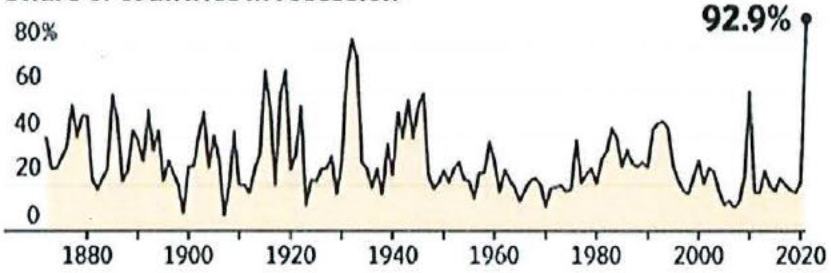
The World Bank semiannual forecast for the global economy predicts a rebound next year, with growth of 4.2%.

Annual change in world GDP



More countries will be in recession this year simultaneously than during the world wars or the Great Depression

Share of countries in recession



Source: World Bank

Even so, the report underscores the extent of the damage wrought on economic activity around the world, even as many wealthy countries begin to emerge from lock-downs.

"We are expecting a more modest recovery in 2021," said Ayhan Kose, the economist who leads the World Bank's global economic forecasting.

In a companion report released last week, the **World Bank said** that **many emerging-market economies will be operating well below** their **potential** even **five years from now**. In the data released Monday, the bank put numerical estimates around the depth of the economic crisis under way.

While wealthy countries are reopening, many emerging markets are still entering a deepening phase of the coronavirus crisis. Brazil, Russia, India and Peru have seen their case counts grow rapidly in recent weeks. The **World Bank expects** the **U.S. economy** to **shrink 6.1% in 2020**, followed by a **4% rebound next year**. The **euro area** will **shrink 9.1%**, **followed by** a **4.5% rebound**.

China will be **one of** the **few countries to expand this year**, the bank said, with **1% growth** followed by a 6.9% rebound in 2021. Even China's economic performance will be the **weakest in** around **45 years**.

The **World Bank**, the international lender that is collectively **owned by 189 member countries** and with the **U.S**. as the **largest shareholder**, is mobilizing up to **$160 billion** in resources to **help countries weather** the **pandemic** and **rescue** their **economies**.

Even with these efforts, the **bank said** that as many as 70 million to **100 million** people around the world **will be pushed into extreme poverty**— defined as **living on less than $1.90 a day**.

Governments Eye a Green Economic Recovery. Some Industries Aren't Convinced.

by Sarah McFarlane – WSJ – Jul. 7, 2020
William Boston contributed to this article.

The **world's top 50 economies** are putting up **$583 billion to boost green efforts**.

Electric cars in production at Renault's factory in Flins, France. The company received a more than $5 billion government loan with environmental conditions.

Governments around the world are spending like never before to kick-start their economies in the wake of Covid-19 lockdowns, in many cases tying green initiatives to rescue packages, even as some industries say saving jobs should trump environmental concerns.

Companies, including Volkswagen AG, Renault SA, Air France-KLM, and Austrian Airlines, are receiving government support aimed at mitigating the effects of the coronavirus pandemic and reducing carbon emissions. But their industries are resisting stimulus packages tied to climate policy, saying governments should prioritize reviving job growth and business activity.

Governments are **pushing** for **change** in some of the **worst-hit industries** with a dual approach: Providing **bailouts** on **condition** that companies **adhere** to

environmental terms and offering help to promote low-carbon solutions such as **electric vehicles** and **renewable energy**.

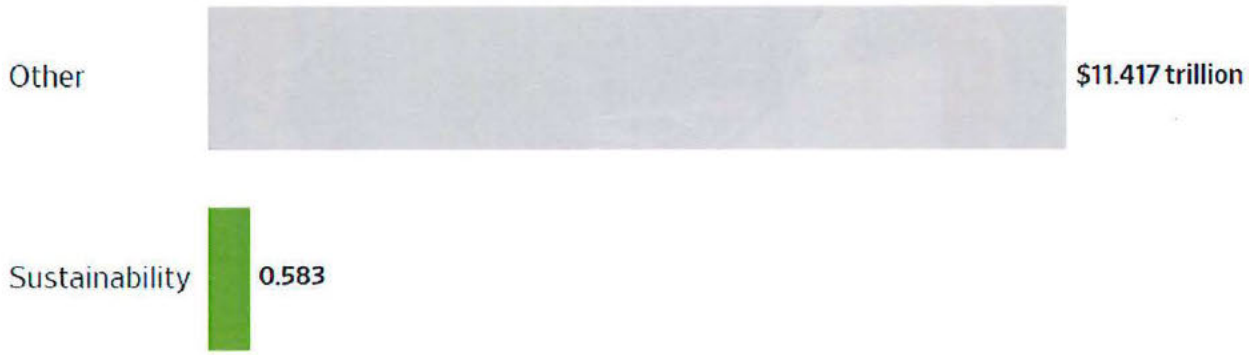
The world's top 50 economies have pledged around $583 billion to boost green efforts, with the **bulk of funds coming from** the **European Union**, according to a report by Bloomberg New Energy Finance published in June.

In the **U.S., lawmakers didn't include climate-related proposals in** the **federal stimulus package**. Separately, the Trump administration extended a deadline for tax credits that support renewable energy investments.

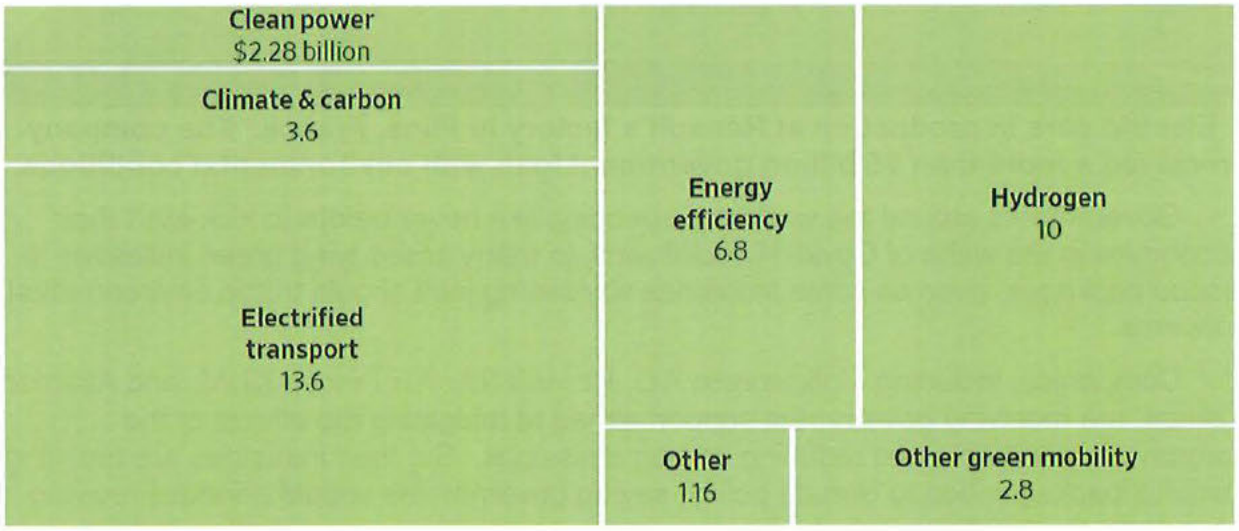
Small Slice

Climate-friendly initiatives are only a sliver of government stimulus packages.

$12 trillion stimulus allocation



...So far, of that $583 billion, only $40 billion has been dedicated to specific areas.



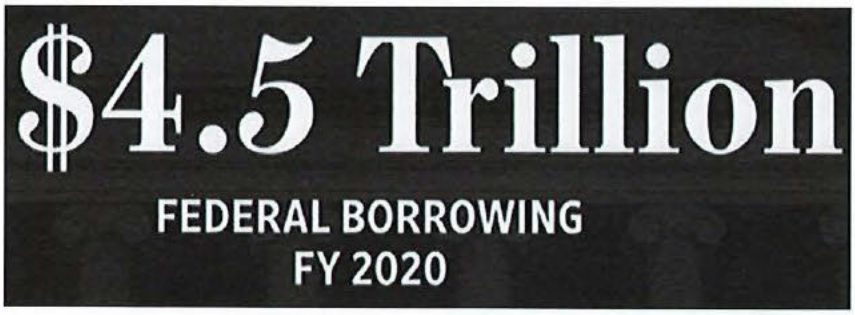
Source: Bloomberg New Energy Finance

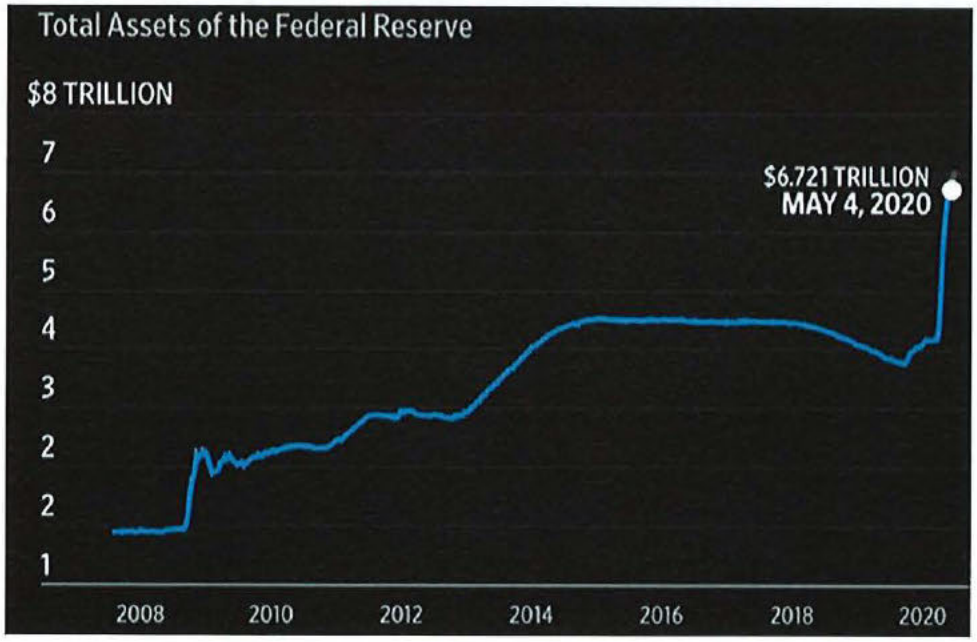
In Europe, the green initiatives have triggered some pushback from businesses. "You have the conservatives in the European Parliament, and some industries like aviation and cars, saying we need to speak to the economic crisis and not to climate as that's not the priority right now," said Belén Balanyá at Corporate Europe Observatory, an organization that monitors lobbying activity.

Businesses say that green initiatives would be too onerous at a time when they need to focus on minimizing job losses and supply-chain disruptions, said Europe's largest business lobby, BusinessEurope, in an April letter to the European Commission. The group, whose partner companies include Renault, KLM and Volkswagen, asked the commission to delay some environmental legislation.

The airline industry said proposals to attach environmental conditions to financial assistance were ill-timed. "Without a return to financial stability it will be impossible for airlines to bring new and more efficient aircraft into service, invest in sustainable aviation fuels or commit resources to improving the efficiency of their operations," said the International Air Transport Association, an airline-industry trade group in an email.

Both **Congress and the Federal Reserve** are **pumping trillions of dollars into** the **economy to fight** the **economic damage caused by** the **coronavirus**. That **stimulus money** is **coming from increased borrowing** over the $1.28 Trillion borrowed by the US in 2019.





Climate activists and scientists hope the support for **climate-friendly** government **spending** will grow from the **current** commitments of **5%** of the **overall $12 trillion** in **stimulus packages** announced **around** the **world**. Green initiatives represent a smaller proportion of stimulus funds **compared with** the packages that followed the **2008-09** financial crisis. At that time, **16%** of **the $3.3 trillion recovery effort** went **toward environmental efforts**, according to the International Energy Agency.

The Organization for Economic Cooperation and Development said in June that governments needed to craft policies that would ensure the world "builds back better" – including by aligning rescue packages with emissions-reduction goals.

Bailouts for some industries including airlines and autos have had climate-friendly conditions attached. Electric-powered transportation has been the clearest target of world-wide government action, data from Bloomberg NEF show.

Government support for electric-vehicle production and demand could accelerate car makers' focus on the electric-car market at a time when they are struggling with poor demand for conventional vehicles and swelling inventories. China recently extended its subsidies for the sector by two years to the end of 2022 and waived purchase taxes for consumers.

Subsidies have helped make China the world's largest electric-vehicle market. In 2018, when the aid could reduce an electric-vehicle's price tag by about $13,000, sales rose by 62%. But subsidies available now are much lower. After Beijing slashed support for buyers sales fell 4% last year, according to the China Association of Automobile Manufacturers.

More broadly, incentives such as subsidies are among several factors that can influence the take-up of electric vehicles, along with charging infrastructure and the range of cars available.

Left: Air France-KLM is receiving government support aimed at mitigating the effects of the coronavirus pandemic and reducing carbon emissions.

The **French government** told state-backed Renault it could only receive a loan of more than $5 billion if the company joined an **electric-battery venture** with Total SA and Peugeot owner PSA Group. Air France-KLM must reduce domestic routes that compete with train services as well as **cut domestic carbon dioxide emissions by 50% before 2024** if it **wants access to a near $8 billion loan package.**

When the **German government** unveiled its **second economic stimulus package** on June 3, it included a **new** round of **incentives** for **electric-car purchases**,

but policy makers stopped short of giving auto-makers the broader financial support they lobbied for.

Volkswagen said the company **welcomed** the **stimulus package**, especially the move to lower sales tax, a spokesman said. "It could have a positive impact on consumption."

The **renewable energy sector**, which accounts for around 10% of global power generation, looks set to get another boost in the latest government stimulus packages. Renewable energy has dominated investments in new power capacity in recent years over coal and gas as costs have come down.

The **EU** said it would **dedicate 25%** of its **recovery package to climate action** and has proposed a **new investment fund** to focus on clean energy technologies such as **wind**, **solar** and **battery storage**. The bloc will invest around **$17 billion** in the fund, according to the European Commission.

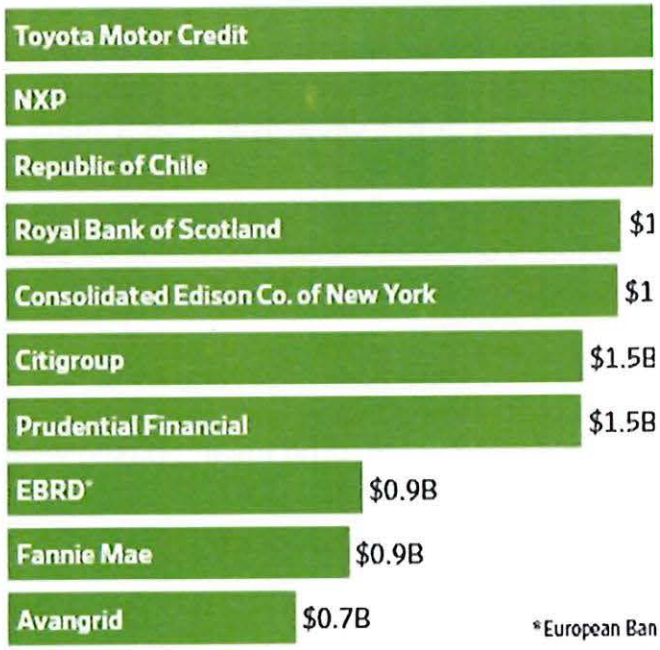
"We were already seeing acceleration away from fossil fuels in several countries before Covid-19, including South Korea, Vietnam, Chile and Indonesia," said Andy Kinsella, chief executive of Mainstream Renewable Power Ltd. The Ireland-based wind and solar business is active in 12 countries, including Vietnam and Chile.

"Anything that accelerates this trend is welcome, and that includes the EU's recovery package," he said.

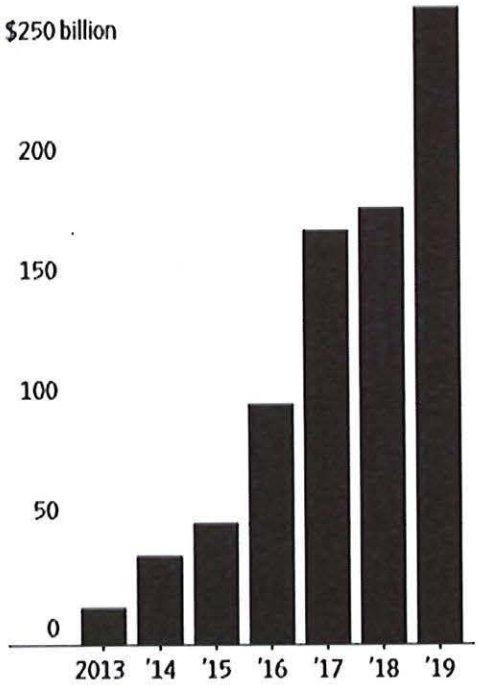
Green Bonds Need the Right Filter

by Jinjoo Lee – WSJ – Jul. 1, 2020

Largest issuers of green bonds in 2020, by issuance



Green-bond issuance



The industry must not let its impressive growth undermine efforts to standardize what counts as environmentally friendly

CHRIS RATCLIFFE/BLOOMBERG NEWS

A unit of oil tanker company Teekay got a green designation for a bond funding.

Green bonds are attracting a growing army of well-intentioned sponsors, certifiers and investors. They need to be careful not to let their own agendas undermine the market's success.

First issued in 2007, **green bonds are debt instruments intended to fund projects with environmental benefits**. By some estimates, there are half a trillion dollars worth outstanding.

Some bonds are intuitively green, such as those that **fund renewable- energy projects**, others less so. Spanish energy company **Repsol** in 2017 issued a green bond to fund energy-efficiency investments in chemical and refinery facilities.

Last year, a subsidiary of crude-oil tanker company **Teekay** received a green designation for a bond funding new tankers with electric engines.

While the bulk of green bonds finance projects in the more safely green territory, these examples highlight their **big weakness**: a **lack of standardization**. External certifiers

now include major credit-rating agencies like S&P and Moody's as well as specialized firms like Sustainalytics, Cicero and Vigeo Eiris, but each has its own methodology.

The slow pace of standardization might reflect the incentives of industry players. The business of structuring and certifying green bonds only makes money if it has a large enough pool of qualifying investments. It if is too restrictive, there would be no market.

And unlike credit ratings, which are based on age-old metrics such as debt to profits or assets, green credentials can be hard to quantify.

As such, **governments might be better suited to setting standards than** the **private sector**.

In June, the European Union began a process to establish a green-bond standard. This would be a good start, though governments too are prone to bias. China, for example, excluded only "clean coal" from the list of projects eligible for green bonds in May, after facing criticism that the fuel doesn't meet international standards. An EU standard could likewise favor technologies and industries that benefit European countries.

I**nvestors aren't naive about** so-called **greenwashing**, where companies market projects with questionable environmental benefit as "green." Teekay's green-bond issue raised only $125 million out of a targeted $150 million to $200 million.

The problem is rather that **as** the **market grows**, so will the **temptation** to **loosen standards**. **Certifiers**, facing more competition, **will find it harder** to **reject business from large potential issuers**. **Green-designated funds will be tempted** to **broaden** the **definition** of "**green**" **when pressured to put more money to work**.

Standards are especially important now that **green bonds seem** to **confer benefits beyond favorable publicity**, including **cheaper borrowing costs**. An ESG-themed bond—one focused on environmental, social and governance concerns – has the **potential** to **price 0.05 percentage point tighter** than a non-ESG-themed bond on new issues. The **differential** can become even **more pronounced** in the **secondary markets**, **according** to **Andrew Karp**, head of global investment- grade capital markets at **Bank of America**.

For this reason, some **renewable- energy companies that initially didn't think** it **was worth** the **extra cost** and **effort** of **labeling their bonds green have jumped on** the **boat**.

In Brookfield Renewable Partners' most recent green-bond issue, roughly a third of participants green-only designated accounts, according to Wyatt Hartley, chief financial officer. While it is possible those accounts would have bought the bond without the green label, Mr. Hartley says the **company** is **better off having done** the **certification legwork before** the **market grows even larger**. He thinks it could lower the company's cost of capital in the future.

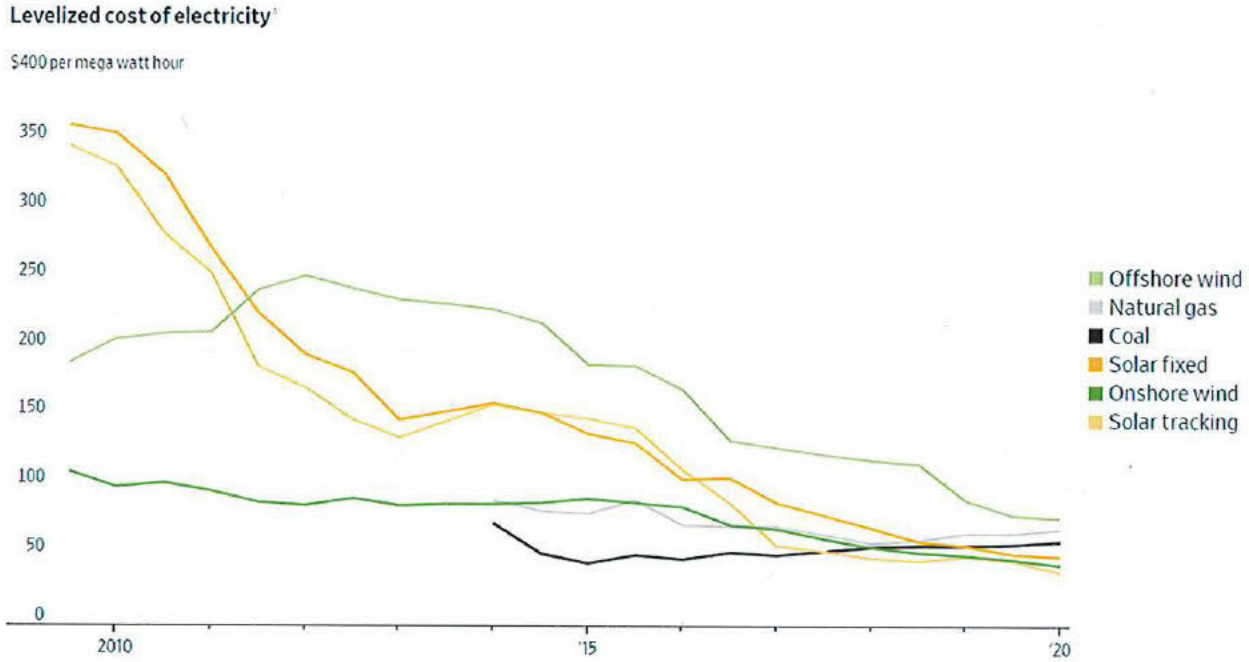
The remarkable growth of green bonds is a testament to genuine recognition that climate risk matters. But as the market snowballs, green boosters on Wall Street will

need to think beyond their own immediate interests. Pull too far and they risk unraveling the market fabric.

Green Energy Is Finally Going Mainstream

by Rochelle Toplensky – WSJ – Jun. 24, 2020

The question for investors now is not whether carbon-free power is here to stay but how to avoid getting burned.



[1]2019 prices
Source: BloombergNEF

After many false dawns, the sun is finally starting to shine on green-energy bets.

Public support for the environmental movement has soared over the past year, as has political backing in many countries. Crucially, the cost of renewable energy can now be competitive with fossil fuels. Government, corporate and consumer interests finally seem to be aligning.

The stock market has noticed. After years of underperformance, indexes that track clean-energy stocks bottomed out in late 2018. The **S&P Global Clean Energy index**, which covers 30 big utilities and green-technology stocks, is now **up 37% over two years**, **including dividends**, **compared with 18% for** the **S&P 500**.

This year's **Covid crisis will delay some renewable projects**, but could speed up the energy transition in other ways. Alternative-energy spending has held up much better than spending on oil and gas. Globally, **clean-energy investment** is now **expected** to account for **half** of **total investment** in the **entire energy sector this year**, **according to UBS**.

Moreover, the crisis has pushed governments to spend money, including on renewable technologies. The massive stimulus plan announced by the European Union last month is decidedly green. The German government increased electric-car subsidies as part of its pandemic-related stimulus package rather than rolling out a 2009-style "cash-for-clunkers" program. China's plans include clean-energy incentives too.

Green Shoots
Value of $100 invested

Source: FactSet

The big question for investors is no longer whether alternative energy is going mainstream, but how best to play it.

Solar and **wind** are **now mature technologies** that provide predictable long-term returns. Big lithium-ion batteries, such as those that power Teslas, are industrializing rapidly. More speculatively, hydrogen is a promising green fuel for hard-to-decarbonize sectors such as long-haul transport, aviation, steel and cement.

Many big companies – the likes of Royal Dutch Shell, Air Liquide and Toyota – have green initiatives worth many hundreds of millions of dollars. They are, however, a relatively small part of these large businesses, some of whose other assets may be rendered obsolete by the energy transition.

At the other end of the spectrum are **lots of unproven clean-tech companies**. Timing is crucial as they can be **hyped to eye-watering valuations** on **little more than excitement** and **forecasts of exponential growth**. **Early-stage electric-truck maker Nikola** jumped on its market debut this month to a **valuation at one point exceeding** that of **Ford**.

Investors might be better off looking at the **established specialists** in between. **Vestas** is the **world's leading manufacturer of wind turbines**. **Orsted**, another **Danish** company, has made the transition from oil and gas producer to wind-energy supplier and aspires to be the first green energy supermajor. More speculatively,

Canadian company **Ballard** has three decades of experience making **hydrogen fuel-cells**.

The **poor long-term track record** of clean-energy stock indexes and funds has much to do with the period roughly a **decade ago** when **Chinese solar-panel manufacturers scaled up** and **drove down costs**. That **accelerated panel installations but crushed margins**, leaving many much-hyped U.S. and European manufacturers, and their shareholders, in the red. That experience remains an important lesson: The **successful rollout** of a **green technology doesn't guarantee shareholder returns**.

Yet **companies** that have emerged from the protracted shakeout **with strong market positions and business models should benefit** as economies clean themselves up. The green revolution is finally happening. Investors just need to be thoughtful about how they join in.

Have corporate green bonds offered lower yields?

By Zach Tokura, MSCI Research, March 10, 2020

Definitions of green bonds can vary widely. Using a standard set of criteria can help investors study how green bonds' yield characteristics compare with those of non-green bonds.

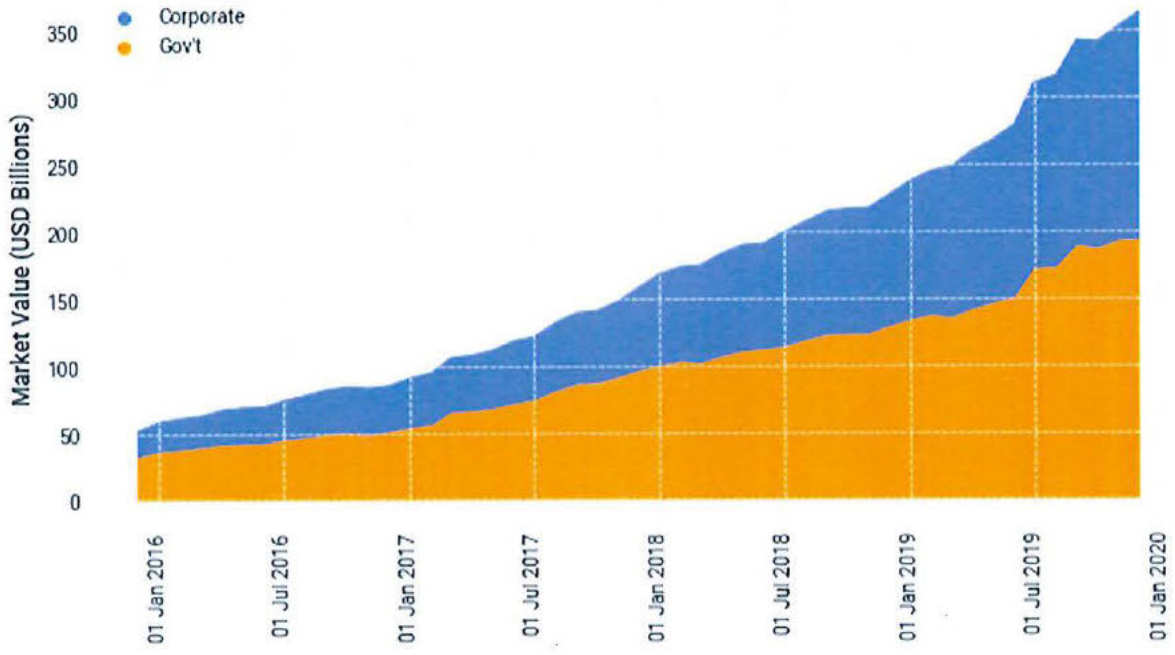
In general, **corporate green bonds tended to offer yields 0 to 2 basis points lower than comparable non-green corporate bonds, during our study period.**

Green bonds from **corporate issuers with higher environmental scores** tended to more reliably offer **lower yields than comparable non-green bonds**.

Green bonds, which finance projects to help the environment, have grown from the time of their first issuance by the World Bank in 20081 into an estimated USD 372 billion market today. Given the rapid emergence of this market, investors question whether corporate green bonds trade at lower yields than conventional bonds.

The definition of green bond can vary widely which presents a challenge for investors who wish to credibly support the environment. To control for this variation, this analysis focused on constituents of the Bloomberg Barclays MSCI Global Green Bond Index, which applies independent inclusion criteria to identify bonds that may have a positive environmental benefit.

Green bonds' rapid growth

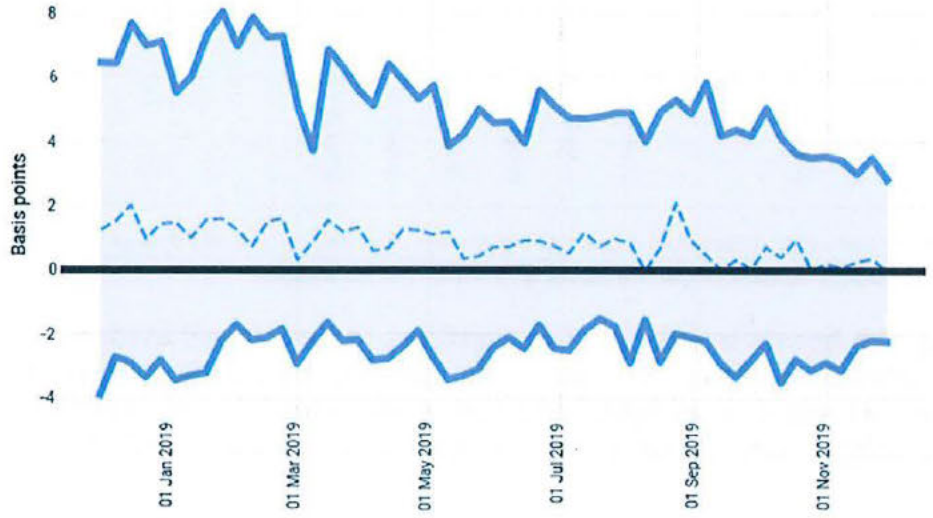


Source: Bloomberg Barclays MSCI Global Green Bond Index, MSCI.

Examining green bonds' lower yields

We looked at the **spread of conventional bonds' yields over green bonds' yields** — the green-bond yield difference. The exhibit below shows the median green-bond yield difference of corporate issuers. Although there was a lot of variation, there **appears to have been a slight (0-2 basis points) difference in aggregate**. As the underlying credit risk is the same for green bonds as non-green bonds, higher demand for green bonds likely drove their yields lower.

Green-bond yield difference of corporate issuers



Source: MSCI RiskMetrics® RiskManager® calculations with MSCI issuer curves. Figure shows median (dotted thin line) with Q1-Q3 band (solid thick lines).

The ESG view

Does the issuer's ESG score matter? The relationship between the greenness of a green bond and the issuer's environmental score is complex: The greenness of a bond reflects the environmental quality of the specific project funded by the green bond, while the issuer's environmental score measures the issuer's long-term resilience in the context of environmental risks. At the same time, it is not unusual for investors to screen issuers using ESG criteria, which may tilt demand toward issuers with high ESG metrics.

The exhibit below compares the green-bond yield difference across issuers with high environmental scores and those with low scores. Note that the dispersion is much tighter, and the yield difference is more consistently positive for high-scoring issuers. Here, only bonds of high-scoring issuers appear to demonstrate any consistent green-bond yield difference, while those of low-scoring issuers did not seem to benefit as much.

Green-bond yield difference was related to issuer's environmental score

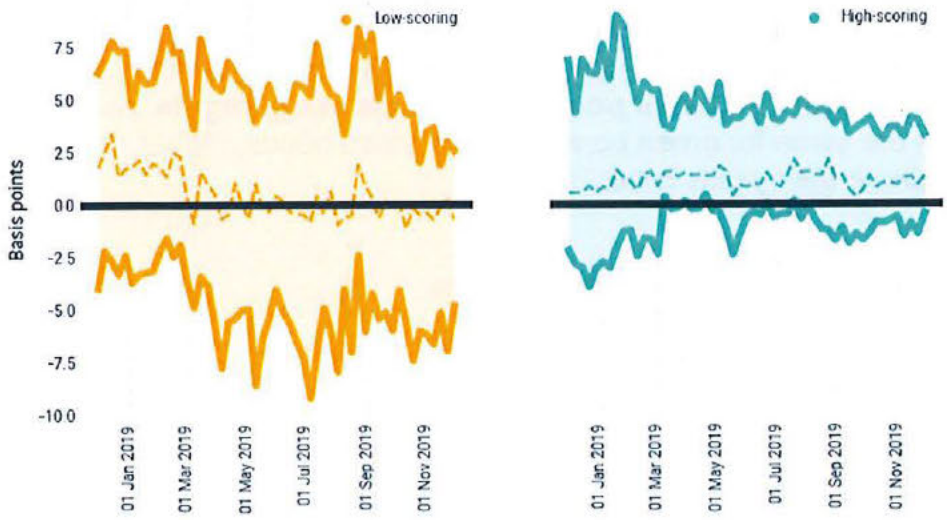


Figure shows median (colored, dotted thin line) with Q1-Q3 band (colored, solid thick lines) for each group. High- and low-scoring groups are bonds of issuers with environmental scores above or below the median, respectively. Source: MSCI RiskMetrics® RiskManager®.

The market for green bonds is expected to continue to evolve, as evidenced by interest from new players such as central banks. Emergent investment themes may call for new analytical tools. Our analysis uses consistent criteria for evaluating green bonds, and we highlight nontraditional views of the market such as the ESG perspective.

How Preferred Stock Has Fared the Past Decade

by Derek Horstmeyer – WSJ – Jun. 8, 2020

Dr. Horstmeyer is an associate professor of finance at George Mason University's Business School in Fairfax, VA.

A look at their returns and volatility, as well as whether preferred shares increase diversification – Be aware: **Preferred stock in** a **crisis will slide like** a **stock**.

Left: Preferred stocks are a favorite of Warren Buffett.

Investors really don't understand **preferred stock**. Some investors, for instance, think that because these investments **pay fixed dividends over time**, their returns should resemble the stability of bond returns. Others think that because preferred shares are "stocks," their returns should look more like that of common stock.

So what does history tell us about the returns and risks of preferred stock? And does adding this often-misunderstood asset class to portfolios increase diversification?

Investigating the universe of U.S. preferred-stock ETFs and mutual funds over the **past 10 years**; we can see that **preferred stocks** have underperformed U.S. equities (the **S& P 500 index**) and **even underperformed U.S. long-term bonds**. U.S. preferred-stock funds averaged an annual return of **7.29% over** the **period**, compared with **7.70%** for **long-term bonds** and **13.52%** for the **S&P 500**.

Source: Derek Horstmeyer, George Mason University

This underperformance of preferred stocks relative to long-term bonds is mitigated by the fact that **preferred stocks** have exhibited **less volatility** over the **past 10 years**. **But** a look at the 2008 financial crisis shows that **preferred stocks** are **exposed** to a particular type of **risk** that **bonds aren't**: **crash risk in times** of **crises**.

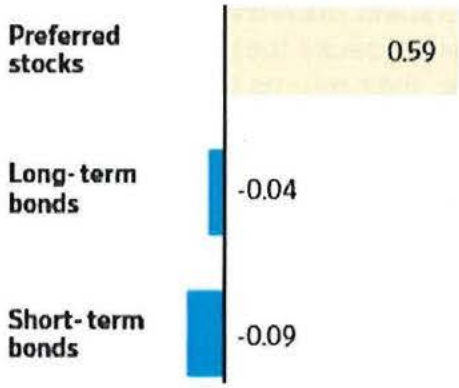
In **2008**, **preferred shares behaved much more like common stock** in terms of their **propensity** to **plummet**. While the **S& P fell 38%** in **2008**, **preferred-stock ETFs** and **mutual funds** lost an average of **25.1%.** Contrary to this, **long-term bonds gained 8.7%** in returns over the **same period**.

The huge difference in returns between bonds and preferred stock is partially explained by the fact that most preferred-stock funds have significant exposure to banks, which suffered big losses in 2008. **Financial institutions** are a **primary issuer**

of **preferred equity**, and preferred-stock funds still average 75% of their holdings in issuances by insurance companies, banks and real-estate groups.

Negatively correlated assets provide greater diversification benefits and reductions in risk than positively correlated assets.

Correlation coefficient between 10-year returns of the S&P 500 and select asset classes



Source: Derek Horstmeyer, George Mason University

When thinking about preferred stock – or any asset class – investors also should consider its **diversification** benefits. The main way to do that is to look at the correlation of its returns with the S& P 500's returns.

Investigating the correlation of preferred-stock funds with the S&P 500 over the past 10 years shows that they are weakly positively correlated (correlation coefficient of 0.59). That means **adding preferred equities** to an all-equity portfolio might **reduce overall risk** a **little bit**.

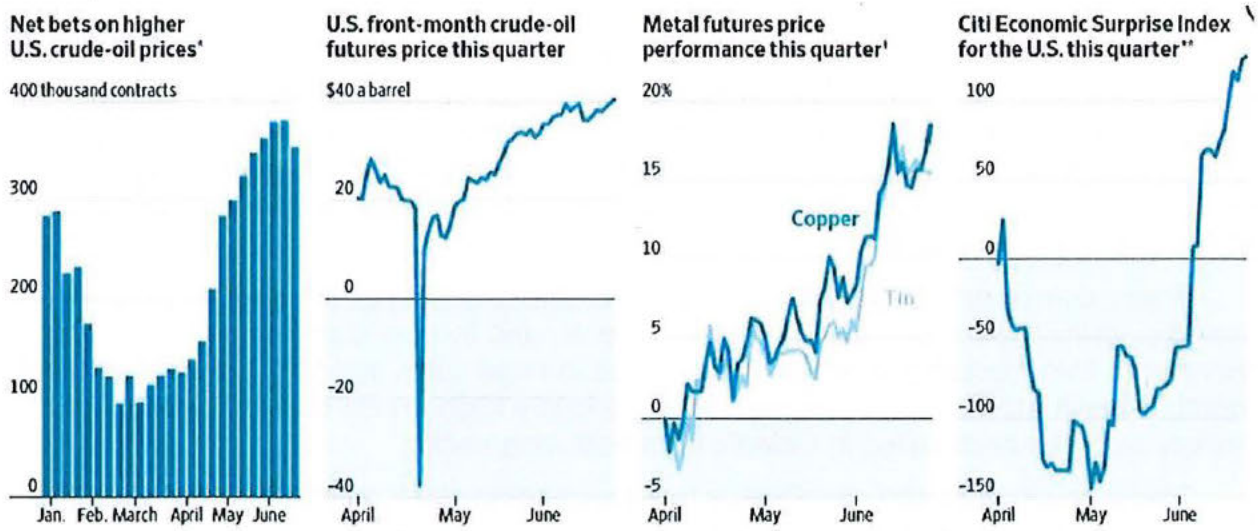
Bonds appear to offer more in this area. **Over** the **past 10 years**, long-term **bonds** are **negatively correlated** with the **S&P 500** and therefore provide great diversification benefits to an all-equity portfolio.

Of course, with every negative look backward in time, there can be a positive outlook going forward. For example, if an investor wants to overweight financials in a portfolio but doesn't fully believe in the strength of financials' common equity due to the low-interest-rate environment (flat yield curve), then the high dividend payments of preferred stock might be enticing.

Similarly, with interest rates at 1% in the bond market and uncertainty high in the stock market due to oil prices and the coronavirus, some investors might be seeking shelter from the storm. If they believe in the strength of the banking sector, then preferred-stock funds might be worth considering.

In a Sign of Recovery, Raw Materials Rally

by Amrith Ramkumar – WSJ – Jun. 23, 2020



*By hedge funds and other speculative investors
†Front-month Comex copper price and London Metal Exchange for delivery in three months tin price
**Positive readings indicate data are generally beating expectations; negative data signal the opposite; data through Friday
Sources: Commodity Futures Trading Commission (net bets); FactSet (oil, copper); CQG (tin); Citigroup via FactSet (surprise index)

Electrolytic copper being produced in central China's Jiangxi province. Copper and tin prices are up more than 15% so far this quarter.

Prices for raw materials including **oil** and **copper** are **surging** as the **world economy reopens for business**, a signal to many investors that global growth is returning more quickly than anticipated.

The recent gains come after coronavirus lockdowns dented commodity prices earlier in the year and are a boon for battered producers like copper miner Freeport-McMoRan Inc. and energy giant Exxon Mobil Corp. – many of which have cut supply in response to industry turmoil. Investors closely watch commodities because their prices fluctuate based on real-time changes to supply and demand and momentum in the global manufacturing sector.

That means **commodity prices tend to climb when factories** are **buzzing** with **activity**, **ships laden with goods** are **moving** around the world and **consumers** are **traveling**. Data recently showed big increases in retail sales and U.S. employment last month, though **joblessness remains** at **historically high levels** due to the pandemic. Activity also has been rising in China's manufacturing sector.

Those trends also are contributing to a burgeoning stock rally that has pushed the **S&P 500 up 39% from** its **March lows**.

China is the **world's dominant commodity consumer**, and the uptick in economic activity there and elsewhere signals that the world economy is in the initial stage of healing from the pandemic, analysts said. Historically, the recovery phase following economic downturns corresponds with big increases in materials prices.

"There's more and more confirmation that we have passed the low, and the fiscal and monetary stimulus keeps coming in," said Jeroen Blokland, a senior portfolio manager at Dutch asset manager Robeco. "That is a very powerful mix." Robeco recently added commodities to the firm's multiasset portfolios for the first time since late in 2013.

With **drivers returning to** the **road**, U.S. **crude-oil futures** have **risen** to their highest level since early March and above **$40 a barrel** – a strong recovery after they briefly fell below $0 for the first time ever in late April due to a lack of available storage. Industrial metals have also been on a tear, with **copper** and **tin up** more than **15% so far this quarter**. Even agricultural commodities like cotton are rising.

As demand increases, the pandemic and early-year collapse in prices are roiling commodity supply chains, which some investors said could fuel further gains.

"The opportunity is phenomenal," said Leigh Goehring, managing partner at natural- resources investment firm G& R Associates. "Supply is just so vastly impacted that you could get a real squeeze in the commodity markets." The firm has increased its investments in energy producers recently while maintaining its positions in copper miners.

Despite concerns that a new spike in global coronavirus cases could derail the run, some traders expect the rebound to continue as demand improves. The Citigroup Economic Surprise Index for the U.S., a gauge of whether growth figures are generally meeting expectations, has risen to its highest level on record in data going back to

2003. **Industrial production in China accelerated in May**, while investment in factories, railroads and new homes is also improving.

Hedge funds and other speculative investors are hopeful. They lifted net bets on higher U.S. crude-oil prices in 10 consecutive weeks through June 9, propelling them to a nearly two-year high, **Commodity Futures Trading Commission data** show. Investors have also pushed up net bullish copper bets lately.

Even if the economic recovery slows down, some analysts are counting on supply reductions and government spending on infrastructure projects and other programs to prevent another commodity collapse.

"Governments around the world are likely to continue to stimulate their economies, helping to boost copper demand from the current low levels," said Freeport-McMo-Ran Chief Executive Richard Adkerson at a virtual industry conference last month. Freeport shares have rebounded 60% this quarter, while shares of S&P 500 energy producers are up 34% during that span.

Some analysts think mining stocks are particularly attractive because supply for industrial materials could remain constrained due to a lack of spending on new projects in recent years. Morgan Stanley found in a recent analysis that mining stocks also tend to perform well after the U.S. economy exits from recessions.

The outlook for oil prices is more murky because large producers in the Organization of the Petroleum Exporting Countries and allies like Russia could increase supply if crude prices keep rising. Some U.S. shale producers like Parsley Energy Inc. and EOG Resources Inc. are also expected to gradually ramp up production in response to higher prices.

Still, some investors are wagering it will be difficult to quickly bring global production back. They are forecasting long-term supply shortages as demand rises.

"Longer term the outlook remains fairly bright," said Candice Bangsund, a portfolio manager at Fiera Capital, which holds an investment in commodities in line with the benchmark it tracks. But in the meantime, "there's still **considerable uncertainty regarding** the **outlook** and little **visibility** as to how the economy will evolve."

Investment-Grade US Corporate Spreads Hit Four-Month Low – Risk Monitor

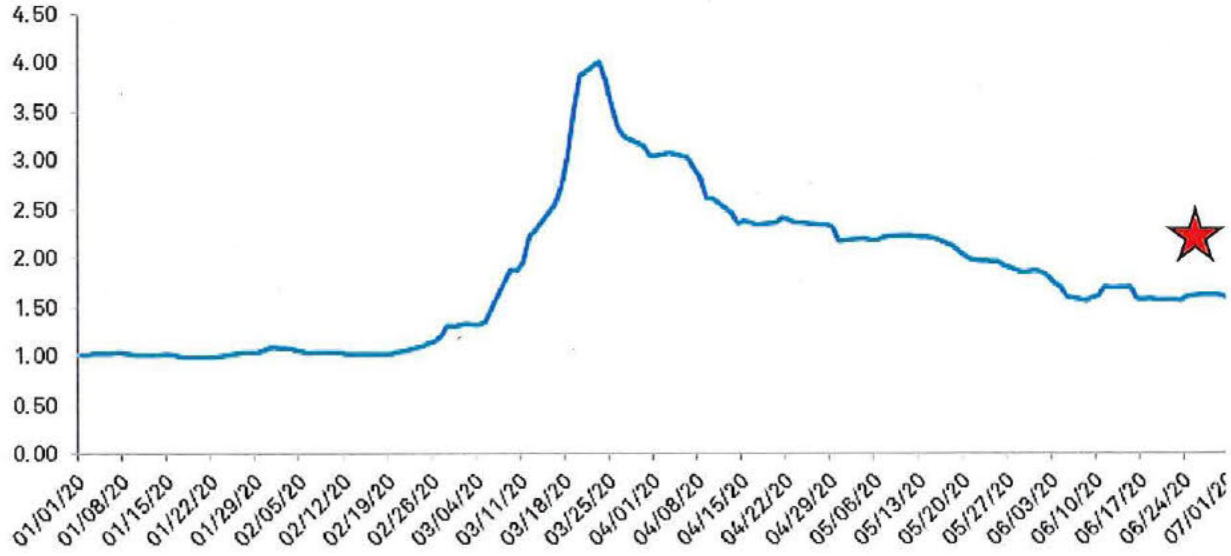
by Peter Brennan – S&P Global Market Intelligence – Jul. 8, 2020

The **spread between investment-grade U.S. corporate bonds and Treasurys fell to** a **four-month low** as **key indicators** of **stress** in **financial markets showed** a **further easing** in the week to July 6.

The **ICE Bank of America** spread fell 11 basis points between June 29 and **July 6**, to **151 bps**, the lowest level since March 6. Having blown out to a peak of **401** bps on **March 23**, the **spread** has **retraced 83.6%** of the **path back to** the **levels before** the **coronavirus pandemic mad**e its **mark in U.S. markets**.

"In credit, just like equities, we have seen a **strong recovery**, perhaps stronger than we would have expected back in April," Mark Holman, chief executive officer at TwentyFour Asset Management, wrote in an email.

US investment-grade corporate bond spread (percentage points)

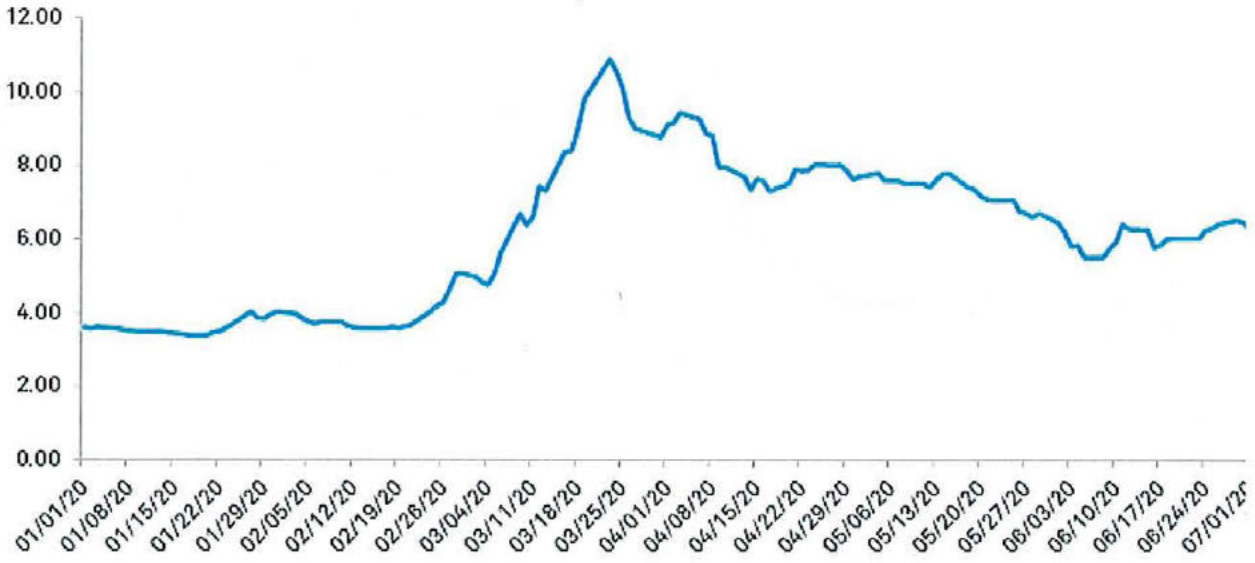


Data as of July 8, 2020.
ICE BofA US Corporate Index Option-Adjusted Spread
Source: Federal Reserve Bank of St. Louis

Ample support from central banks and fiscal policy has boosted liquidity and allowed record bond issuance. Investment-grade companies borrowed a record $1.129 trillion in the bond market in the first six months of 2020, according to LCD, an offering of S&P Global Market Intelligence.

Issuance by high-yield companies was also at an all-time high in the first six months of the year, at $210.6 billion, but the spike in debt availability has proven more troublesome in this sector. Between June 29 and July 6 the spread tightened by 49 bps to 603 bps, exactly reversing the 49 bps widening in the previous seven-day period as investors were attracted by the yields on offer.

US high-yield corporate bond spread (percentage points)

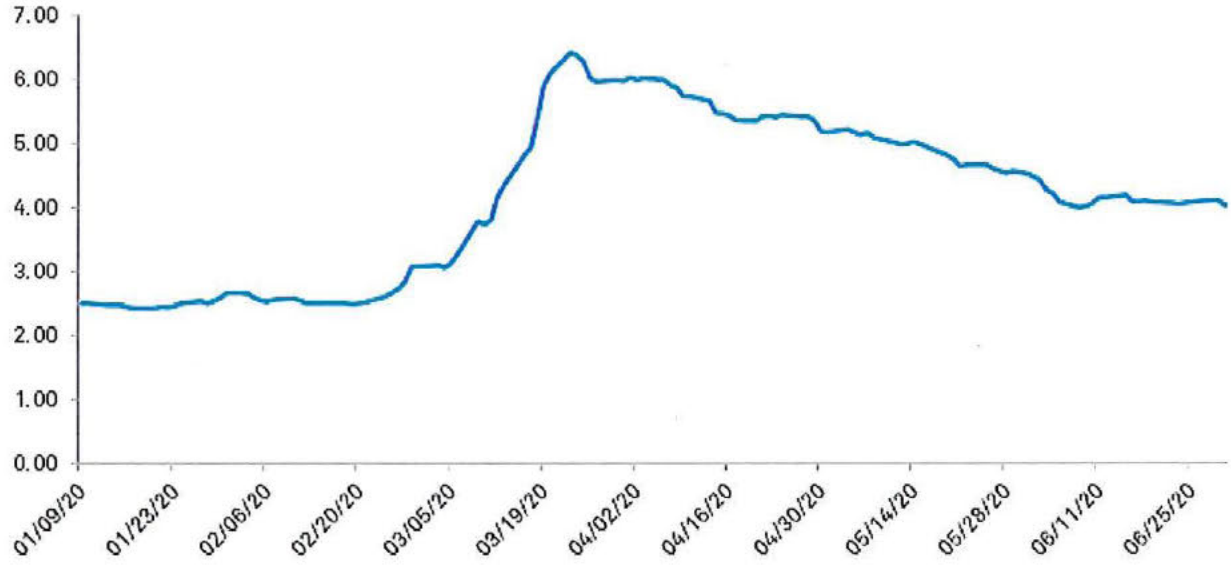


Data as of July 8, 2020.
ICE BofA US High-Yield Index Option-Adjusted Spread
Source: Federal Reserve Bank of St. Louis

"Default rate expectations are being marked lower as the authorities have indeed saved the day for many firms, and yields are still a lot more attractive than at the start of the year," Holman wrote.

The easing in financial conditions extends to emerging markets where the spread on investment-grade corporate bonds fell 19 bps to 392 bps, the lowest level since March 11.

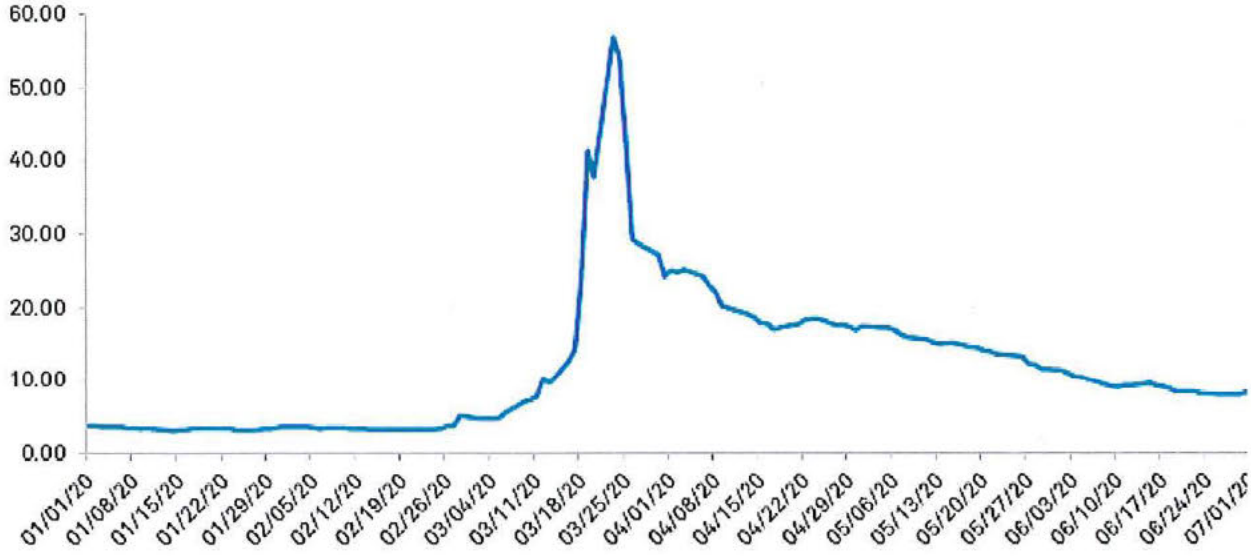
Emerging-market corporate bond spread (percentage points)



Data as of July 8, 2020.
ICE BofA Emerging Markets Corporate Plus Index Option-Adjusted Spread
Source: Federal Reserve Bank of St. Louis

The U.S. loan market was also returning to levels last seen in mid-March. The percentage of the S&P Global-rated U.S. loan index priced below 80 — a closely watched indicator of stress measured by LCD — fell to 7.8% on July 6, down from 7.9% a week earlier.

Share of S&P US Loan Index priced below 80.0 (%)



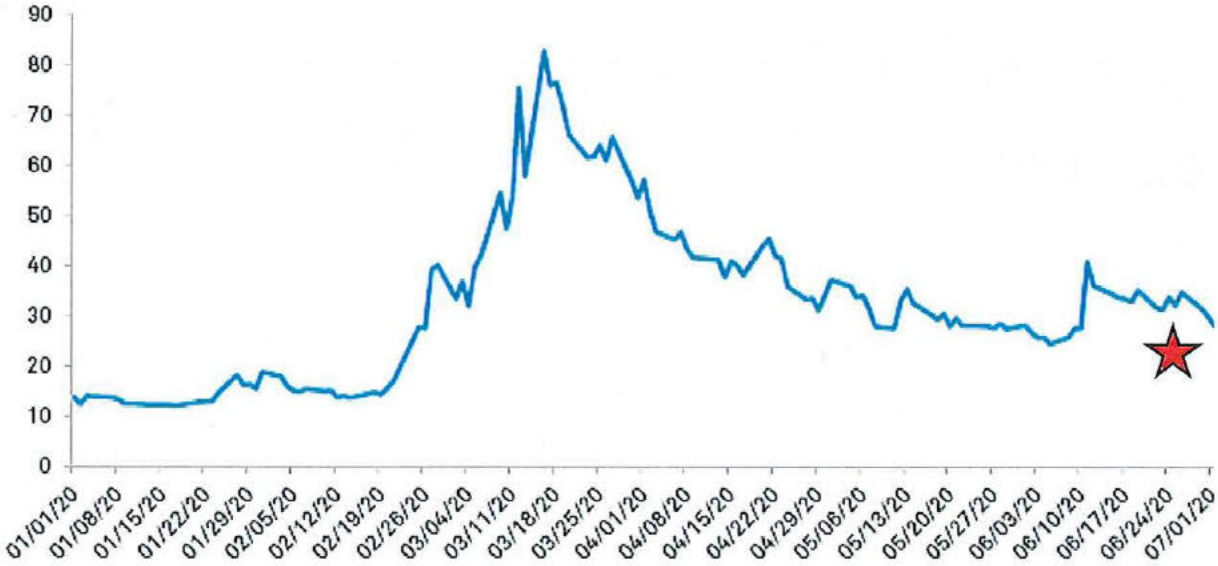
Data as of July 8, 2020.
S&P U.S. Leveraged Loan Index
Source: LCD, an offering of S&P Global Market Intelligence

Whereas credit spreads have generally been driving downward since the peak of the panic in financial markets, volatility has remained rife in equities, with investors undecided as to whether they are spooked or encouraged by different releases of economic data.

The **VIX**, or volatility index, **suggests** that **investors expect volatility** in **the S&P 500** to **remain elevated** over the **next 30 days**. At 29.4 on July 7, the index was down slightly from 30.4 on June 30 but was still at a historically high level, more than double the 13.9 January average.

"While central bank support can maintain the credit market and avoid refinancing risks, we are **concerned about** the **growth outlook and** its **potential** to **spur equities higher**," noted **Alex McKnight**, **investment director at GAM Investments**.

VIX flattens out after record-high volatility but remains elevated

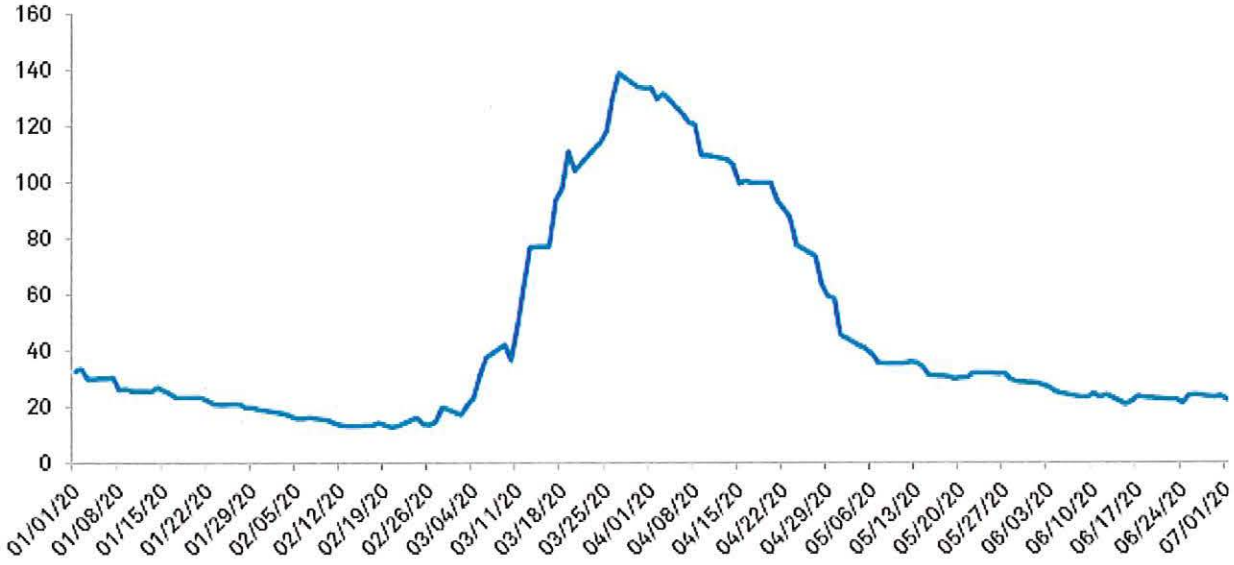


Data as of July 8, 2020.
Source: Chicago Board Options Exchange

The stress in bank lending also eased in the last week, according to the Libor-OIS spread, a key risk indicator for the U.S. banking sector.

The spread, which measures the difference between the three-month dollar London interbank offered rate and the overnight indexed swap rate, was 18.7 bps as of July 7, down from 23.7 bps on June 30.

Libor-OIS spread flattens (basis points)



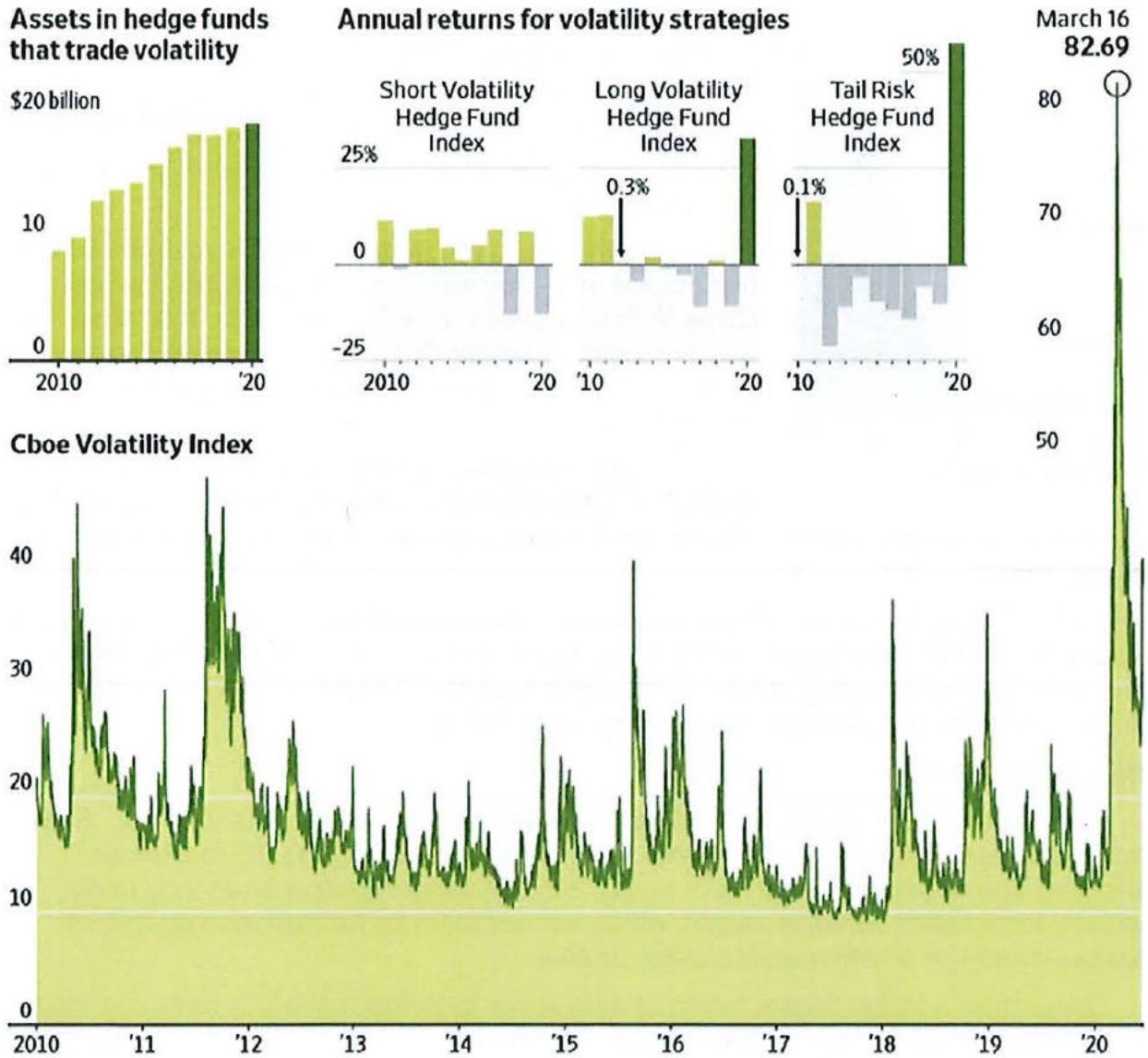
Data as of July 8, 2020.
Source: Refinitiv

Investors Bet on Volatility, Making Markets Even Wilder

by Gunjan Banerji WSJ – Jun. 13, 2020

Dramatic stock swings spark booming interest in a risky tactic.

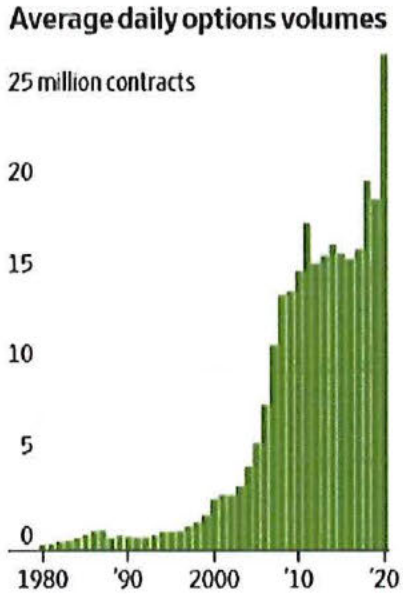
Markets were **once dominated** by **bulls** who **thought stocks would go up** and **bears who thought** they would go **down**. **These days**, **another animal** is on the rise. It **doesn't much care what stocks do**, **as long as they do something**.



Sources: Hedge Fund Research (assets); Eurekahedge (returns); FactSet (index) Note: 2020 figures for assets and returns are as of the end of March.

These investors are focused on **volatility**, the **amount** of **movement** in **prices over time**. In recent years, volatility has gone from a specialty of derivatives traders to a vehicle for trading in its own right. **Investors** big and small are **wagering hundreds** of **billions** of dollars **on volatility**, including by betting directly on the moves of measures like the S&P 500, shares of individual companies or oil prices.

The pandemic has cemented its arrival, luring fresh cash and interest as stock swings jumped to new levels. Since then, big moves in stocks – both up and down, including a drop of more than 1,800 points in the Dow Jones Industrial Average on Thursday – have provided traders with ample opportunity to profit.



Source: Options Clearing Corp.

Volatility trading has grown so big that trading on expected market moves can itself move markets. Bets on lower volatility can spur a cycle that magnifies periods of calm. At other times, the strategies can worsen downturns once they begin.

Tools used to trade volatility, such as options, have flourished, with contracts tied to trillions of dollars' worth of stocks changing hands in any given week, according to data provider Trade Alert.

"It **started out as** a **metric**," said Devesh Shah, who first helped make the widely watched volatility gauge, the **Cboe Volatility Index**, or **VIX**, tradable in 2004 while he was at Goldman Sachs Group Inc., before retiring as a partner. "Now...the genie is out of the bag and volatility is everywhere."

Today's economic uncertainty means that volatility trading, and therefore also volatility itself, is likely to stay elevated as investors seek to either protect themselves from it, or, increasingly, to make money from it.

"I don't think there's ever been a time when there's so much uncertainty," said Paul Britton, founder of Capstone Investment Advisors LLC, one of the biggest investment firms specializing in trading volatility, managing roughly $7 billion. "That is typically good for volatility practitioners. Uncertainty is our friend."

Explosive gains:

Tactics tracking volatility range from extremely risky to relatively innocuous. Some trade volatility itself, tapping derivatives tied to the VIX or using options to express whether market swings will shrink or swell. Sophisticated investors have long used esoteric tools called variance swaps, which can set them up for explosive gains – or losses – based on whether stocks crash or soar.

More than a trillion dollars' worth of derivatives bets tied to the VIX have changed hands this year, according to Cboe Global Markets data, more than quadruple the figure a decade ago. Funds sitting in volatility exchange-traded products rose to a high of almost $12 billion, according to FactSet data, and trading volumes for many surged to a record during the recent tumult. At times this year, a volatility product was among the most popular exchange- traded products in the entire U.S. stock market.

This year, assets under management for hedge funds trading volatility hit a record $19.4 billion, according to industry tracker Hedge Fund Research, more than double the amount a decade ago. Such strategies have attracted big investors like the $395 billion

California Public **E**mployees' **R**etirement **S**ystem, the **largest public pension plan** in the **U.S.**, and the **Virginia Retirement System**.

In other strategies, volatility is used as a metric driving buying and selling decisions. About $330 billion is invested in volatility – control funds, up from $123 billion in 2010, according to estimates from Joseph Becker, a director at Milliman Financial Risk Management.

The business of volatility took off after the financial crisis, as exchange operators and bankers devised new, and risky, ways to trade it. The first exchange- traded product tied to the VIX – known as Wall Street's "fear gauge" – was introduced in 2009, shortly after markets around the world collapsed.

After the last recession, a fear of steep stock losses spurred a rush into products promising to rise when markets are tumbling. The ensuing decade of ultralow interest rates led investors into increasingly creative tactics to juice returns and generate steady income.

One of the strategies at Mr. Britton's firm, Capstone, that involves betting on the differences in swings between the broader stock market and individual shares has returned 12% through May, according to a person familiar with the matter. Its flagship volatility strategy has returned 2%. By comparison, the S& P 500 was down 5%, including dividends, for the same period.

Another Capstone strategy, designed to trade violent swings in the stock market during crises, has returned 220% through May, this person said. These events are referred to as "**tail risks**," events with a statistically minute probability of occurring.

The returns this year are in part thanks to a bet in January that investors weren't fully grasping the giant risk that the coronavirus posed to the world. As the virus spread through China and U.S. stocks hovered near records, Mr. Britton flagged the danger at a weekly meeting with his investment committee in New York.

"I would say: 'Visualize CNN running a story where a healthy mother of two from the Midwest dies from the coronavirus… and visualize what that means to the market,' " Mr. Britton said. "That's going to be playing for 72 hours, nonstop, on loop."

The firm started buying inexpensive options and hedges tied to the VIX, the person familiar with the matter said, contracts that would pay out handsomely as major U.S. indexes began tumbling in late February, abruptly ending the nearly 11-year bull market for stocks.

It's a sharp shift from recent years when bets flourished that markets would remain calm. Mr. Britton once addressed a room full of fellow volatility hedge-fund managers at his annual conference, the Global Volatility Summit, donning a red cap with the words "Make Vol Great Again" stitched on its front in white letters. It was March 2017, shortly after President Trump's inauguration, when calm swept through markets and stocks soared.

Many attendees of those summits say volatility is an asset class of its own, akin to stocks and bonds as a must-have in a portfolio. Mr. Britton says investors need to look

to different strategies that will generate returns in times of market turmoil, with bond yields near record lows.

Ernie Chan launched his tail-risk strategy after taking severe losses trading currencies in the wake of the 2011 downgrade of U.S. Treasurys. That event roiled markets and wiped out about a third of his firm's assets at the time. He thought a volatility-focused strategy would shield his firm, QTS Capital Management, from taking another brutal loss. Its trading program, which kicks in under certain conditions, often goes quiet for long periods before a burst of activity.

Mr. Chan was on a cruise ship in February when his cellphone was inundated with messages. After months of inactivity, the program was trading in a frenzy. "It's almost like a pandemic prediction system," said Mr. Chan. "It detected that something is not going well in the world and it started to let us trade."

Based in Ontario, Canada, while his business partner has been sheltering from the pandemic on one of New Zealand's remote islands, Mr. Chan considers the firm, which oversees about $29 million in its tail-risk strategy, crisis-proof. March, the most volatile month in the stock market's history, was its best month ever.

Tail-risk volatility strategies followed by industry tracker Eurekahedge have returned 57% this year through March.

In recent years, many pointed to the popular trade of betting against volatility as part of the reason markets were so placid. Investors big and small turned to selling options in a bid that markets would stay tame. Dealers at banks or market-making firms who were the end buyers of these options contracts often hedge themselves in the stock market, buying into falling markets and selling into rising markets.

At other times, the trades have been blamed for exacerbating instability.

"The exposure in these derivatives is so significant now that it's often the tail wagging the dog," said Cem Karsan, a senior managing partner at volatility hedge fund Aegea Capital Managements LLC, which oversees about $250 million. "It's definitely a structural change in how markets work."

Turbulence:

This was on display in February 2018, during what became known as "volmageddon," when two volatility exchange-traded products collapsed during a bout of turbulence, and again in March of this year. Some said options hedging activity was exacerbating stock swings. This activity can also help drive swings in the last half-hour of the trading day, when stocks are prone to outsize moves, according to research from Barclays PLC.

Mr. Chan says hedging by options traders and buying and selling by exchange-traded funds can drive stock moves, particularly at the end of the day. That gives him an opportunity to make money from the wild intraday swings.

Like other traders, Mr. Karsan says the **distortions create opportunities** for him to buy and sell derivatives, **taking advantage of minuscule price discrepancies**.

Access to exchange-traded funds have made it easy for individuals like Dennis Murphy to join the trades. After the former immigration officer received a pin congratulating him for 25 years of government service, he quit out of dissatisfaction with his career. He initially tried his hand at trading stocks around earnings releases but didn't have much luck.

"Then a friend of mine told me, 'Hey, did you ever look at these things called ETFs?' " Mr. Murphy said. "I didn't know what an ETF was. I have no financial background."

He landed on his specialty in 2016: the ProShares Ultra VIX Short-Term Futures ETF, known as UVXY, which tracks complex derivatives and can be easily traded on stock exchanges. Now, he said, he can comfortably support himself trading volatility full-time from his apartment in Manhattan, usually sitting in front of three computer screens.

Navigating the market selloff this year has been trying. "I would love to take my blood pressure while I'm waiting for a trade," he said. "I don't think I'm on the edge of my seat. I think I'm 2 inches off of it."

The notoriously risky products have left others with big losses. By design, many of them consistently lose money over time, in part because of quirks related to trading derivatives tied to the VIX.

The recent stretch of market turbulence has been littered with soured volatility bets. The Alberta Investment Management Corp., which oversees more than 100 billion Canadian dollars (US$73 billion) in pension and endowment funds in Canada, estimated it would take losses of about C$2.1 billion on a volatility-related investment strategy.

"Markets behaved in a manner never-before-seen and the result was a very unfortunate loss," CEO Kevin Uebelein said in a written statement.

New York-based hedge-fund firm Malachite Capital Management LLC shut its doors in March, citing "extreme adverse market conditions." Allianz Global Investors said it was liquidating two hedge funds after heavy losses on stock options trades, The Wall Street Journal reported.

Chris Walvoord, who advises big investors at Aon Investments USA Inc., said it can be difficult for some investors to manage the risk that comes with complicated derivatives. His clients, including pensions, endowments and insurance companies, recently held about $4.7 billion in volatility-related investments.

"The tide goes out and you see who's not wearing a swimsuit," he said. "You don't know who's doing a good job and who's not doing a good job until you have a big dislocation."

Investors Flee Market Volatility by Going to Cash

by Gunjan Banerji – WSJ – Jun. 17, 2020

Investors have rarely been this flush with cash.

Grappling with the most economic uncertainty in decades and a head-spinning stretch of volatility in the U.S. stock market, many investors have rushed into money-market funds. Assets in the funds recently swelled to about $4.6 trillion, the highest level on record, according to data from Refinitiv Lipper going back to 1992.

It is a "pantry-loading and survival" mentality, said Peter Crane, founder of Crane Data, which tracks the industry. "It's blown the lid off the previous record high."

Assets in money-market funds are one, but not the only, measure of cash holdings, and investors have socked away cash in other places, too. Other measures, like bank deposits, are also at a high.

Analysts attribute the flight to cash to the coronavirus pandemic, which spurred a rush out of stocks, bonds and commodities. Meanwhile, stimulus checks sent to millions of Americans as part of the economic rescue package helped add to the heap.

It is the latest perplexing signal in markets, coming as many investors are already struggling to reconcile the economic downturn stemming from the coronavirus pandemic with the simultaneous, staggering rally that has pulled major U.S. stock indexes up more than 35% off their lows of late March.

Few can agree on what the giant pile of cash means for markets. Many investors, nervous about the economic downturn, are questioning if stocks have soared too far, too fast, and have chosen the safety of cash over investing in the market. Others are keeping cash on the sidelines, ready to deploy when they spot an attractive buying opportunity.

Anxiety surrounding the market's run-up has been on display recently, with the S&P 500 plunging 5.9% on Thursday – its biggest drop since March – before swinging wildly on Friday and Monday. The index has surged 40% since late March and is off just 3.3% for the year.

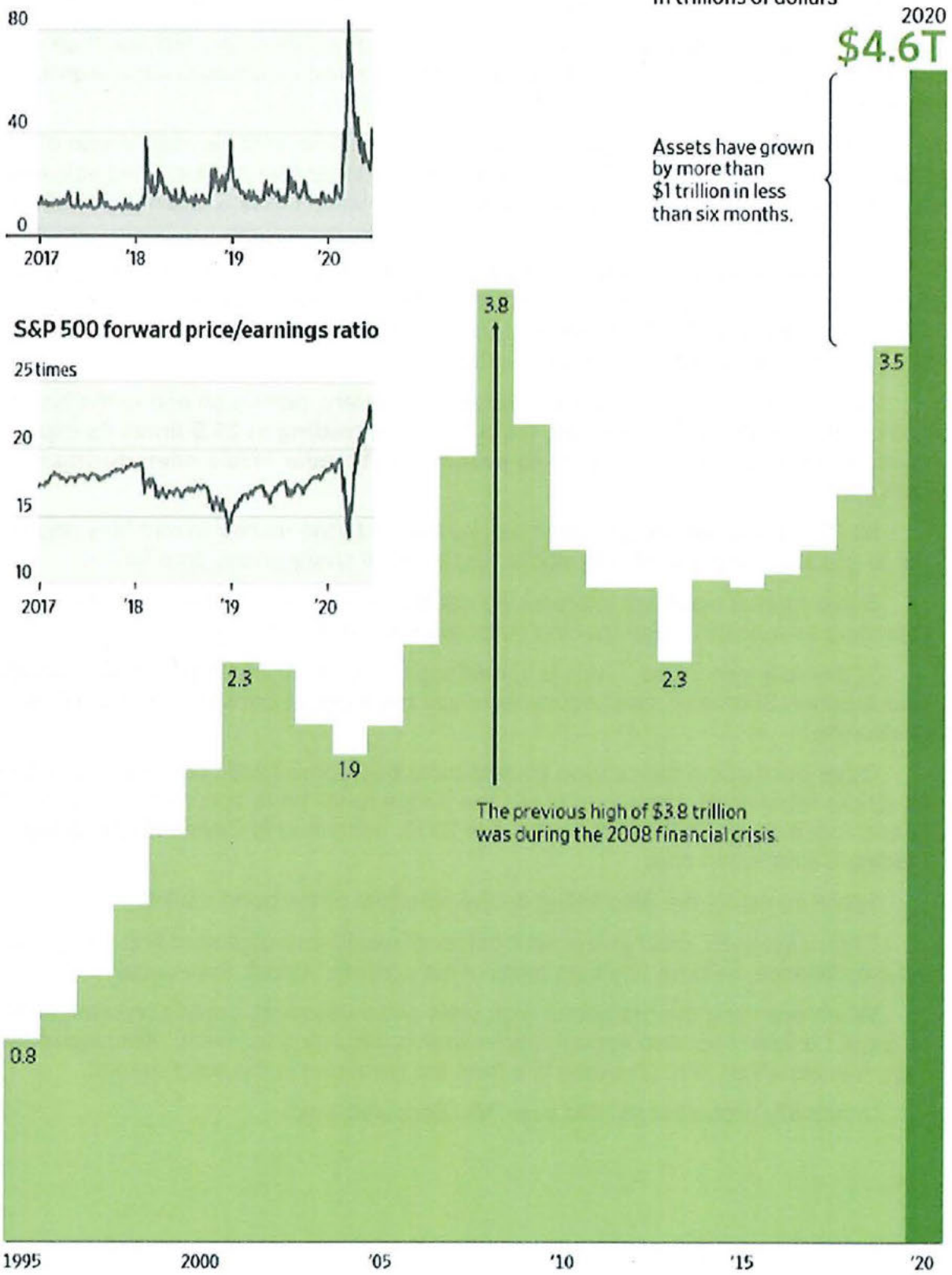
Yet despite the advance, overall stock positioning among investors remains among the lowest levels of the past decade, according to data from Deutsche Bank. New individual investors jumped into the stock market during the recent selloff, while bigger institutional investors only recently started adding to stock positions, a team of Deutsche Bank strategists led by Parag Thatte said in a June 5 research note. John Cunnison, chief investment officer at investment firm Baker Boyer, said he moved some of his portfolio into cash earlier this year when volatility first started creeping into markets—marking the first time in at least a decade that he hasn't been fully invested in stocks or other assets.

He isn't alone. **Assets in money-market funds** have **grown** by about **$1 trillion this year**, **pushing** assets in these **funds above** the **prior high** of roughly **$3.8 trillion** reached **during** the last **financial crisis**.

Cboe Volatility Index

S&P 500 forward price/earnings ratio

Assets in money-market funds
In trillions of dollars



Sources: FactSet (index, P/E); Refinitiv Lipper (assets)

Note: Assets for 2020 are as of June 10.

Like many other investors, Mr. Cunnison has been struggling to reconcile the divergences between the deteriorating economy and the improving stock market.

"It does justify some higher level of caution and resilience in portfolios than you otherwise would have," Mr. Cunnison said. "We're still comfortable with a slightly higher level of cash."

Jeremy Grantham of GMO LLC, who earned acclaim with his calls ahead of Wall Street busts in 2000 and 2008, wrote in a quarterly letter that stock-market valuations are among the highest they have been historically, while the U.S. economy is about as abysmal as it has been.

"Everyone can see and feel that this is different and can sense the bizarre nature of the market response: we are in the top 10% of historical price earnings ratio for the S&P 500 on prior earnings and simultaneously are in the worst 10% of economic situations," Mr. Grantham wrote in his letter to investors.

The U.S. officially entered a recession in February, putting an end to the historic 128 month expansion. Meanwhile, the **S&P 500** is **trading at 21.9 times** its expected earnings, putting its **forward price-to-earnings ratio near levels seen during** the **dot-com bubble**.

Mr. Cunnison said he put some money back into the market in mid-May and would like to gradually wade back into stocks, especially if share prices drop further.

Some market watchers interpret the cautious positioning by investors like Mr. Cunnison as a positive sign that the stock market has room to run.

"If this rally continues … this is something to fuel a continued rise in U.S. equities," said Stephen Suttmeier, chief equity technical strategist at Bank of America, of the positioning.

Other positioning data shows traders have been pessimistic about the recent rally. As stocks rebounded, leveraged funds like hedge funds have accumulated the most bearish position on S&P 500 futures since 2016, according to Commodity Futures Trading Commission data.

Some investors are also sitting on the sidelines of the bond market.

Chris Zaccarelli, chief investment officer of wealth-management firm Independent Advisor Alliance, said he has held more of his portfolio in cash than usual.

When scanning the market for high-yield and investment-grade corporate bonds, he says, he hasn't spotted enough appealing opportunities to invest. Keeping money in cash has benefited him, shielding him from the gyrations in the bond market.

"It actually protected us" this year, Mr. Zaccarelli said.

Investors Learn to Love Wind, Solar Power

by Rochelle Toplensky – WSJ – Jul. 7, 2020

Renewable energy has become cheap and offers utility like returns.

Wind Turbines and solar panels produce energy more cheaply than coal or gas.

After a stormy, dependent youth, the **wind-and-solar-energy industries have matured into boring, profitable middle age**. This year's **plunging interest rates** make that a more appealing proposition than ever for investors.

Wind turbines and solar panels, which once proliferated thanks to government handouts, now produce energy more cheaply than coal and natural gas. **Chinese manufacturers** a **sell solar panels at fifth** of the **price** a **decade ago**. **Bigger wind turbines** and **better installation** methods have **halved their cost**. These developments tripped up a previous generation of green-minded investors but look to have run their course.

Subsidies now mostly focus on upgrading the distribution infrastructure. Wind and solar are intermittent but can provide a constant flow of electricity in combination with storage – batteries or hydro – or gas.

Governments run auctions to gather electricity prices from potential suppliers. The winner has the right to build and signs a long-term contract to sell power at the bid price. Unsubsidized renewables are routinely at least as cheap as fossil fuels.

Google, Walmart, Amazon and other big corporations also have been **signing power-purchase agreements directly with clean-energy producers**.

After contracts end, producers sell the power into the local market. The risk that open-market prices drop seems slight given the inexorable rise of energy usage. Demand for power and projects has been relatively resilient **during** the **Covid-19 crisis,** though **some installations have been delayed**. Long-term economic growth in the developing world is expected to buoy demand.

Pension funds, insurance companies and **other institutional investors** have been **attracted** partly **by** the **green theme**, but mostly by the **promise** of a **steady, long-term income**.

In private markets, **projects typically pay returns** in the **high single digits** in **developed countries** and more elsewhere. That **compares with** a **10-year Treasury yield** of **around 0.67%** in the **wake** of the **pandemic**.

For public investors, there are some listed companies that build and operate renewable installations. Toronto-listed Brookfield Renewable Partners operates 19 gigawatts of production across North and South America, Europe, India and China. The shares trade for about two times book value and offer a 4.5% dividend yield "I'd put my money on the sun and solar energy," Thomas Edison reportedly told his friend Henry Ford in 1931. It has taken many years, but that is finally starting to look like better investment advice.

Investors may pay 'greenium' as green bond demand outstrips supply

By JahanZaib Mehmood and Jennifer Laidlaw, S&P, March 28, 2020.

Supply in the green bond market is struggling to keep up with demand as investor interest continues to grow. As a result, **investors could end up paying a premium simply to buy in**.

Climate change and how businesses deal with it are **becoming an increasingly important issue for investors** as they demand more transparency to evaluate investment risks. **Total issuance of green bonds** — debt that finances environmentally friendly projects — is **expected to reach $250 billion in 2018**, from a virtual standing start in 2012, according to data from the nonprofit Climate Bonds Initiative, or CBI.

Despite the rapid expansion of the market, however, **demand for green debt continues to outstrip supply** as institutional investors increasingly apply environmental, social and governance ESG criteria to their investment policies. Partly as a result of this, **the average final pricing** of U.S. dollar- and euro-denominated green bonds is **around 2 basis points tighter**, relative to initial pricing thoughts, than that of "vanilla" bonds, according to the CBI.

That figure is roughly in line with general market chatter, according to Michael Wilkins, head of sustainable finance at S&P Global Ratings.

"It does vary but typically **people say around 3 basis points is what you see as a pricing advantage**," Wilkins said. "It does vary from bond to bond and **some bonds have achieved a higher advantage**. The biggest reason is the **lack of supply versus demand**."

'Greenium' could offset added green bond costs

New bond issuances typically price with a yield slightly higher than that on equivalent debt from the same issuer already trading in the secondary market, in what is known as a new issue premium. But of a dozen third-quarter 2017 green bond issuances studied by Climate Bonds Initiative, two were priced with a "greenium," indicating that they yielded less than existing debt, while four others priced with no new issue premium.

The yield reflects the coupon, or interest rate, paid on a bond adjusted for the percentage of face value paid by the acquiring investor. The yield falls as the price rises.

All other things equal, green bonds are slightly more expensive for an issuer, because it must monitor the debt's compliance with generally accepted principles for such securities. **Being able to place the notes with a "greenium" could help offset that**, said Robert Scharfe, CEO of the Luxembourg Stock Exchange, which operates a green bond exchange.

On issuance, green bonds "are swallowed up immediately," meaning that there is ample demand in the secondary market, Scharfe added.

Spread changes of select euro-denominated green bonds

Ticker	1 week	1-week basket	Greater than basket	1 month	1-month basket	Greater than basket
EIB 2047	-0.13	-0.78	×	-5.44	-3.48	✓
SNCF 2047	-1.33	-0.78	✓	-3.45	-3.48	×
Municipality Fin. 2027	-6.83	-4.14	✓	-12.35	-6.34	✓
NRW Bank 2027	1.50	-4.14	×	2.23	-6.34	×
Deutsche Kreditb. 2024	-0.09	-0.59	×	-0.69	-2.93	×
Engie 2023	-4.64	-4.26	✓	-3.52	-7.41	×
SSE 2025	2.02	-4.26	×	-3.52	-7.41	×
Engie 2029	-3.23	-7.07	×	-8.05	-11.33	×
Hypo Vorarl. 2022	-6.18	-2.16	✓	-8.77	-4.72	✓
Iberdrola 2027	-4.44	-3.12	✓	-4.31	-5.80	×
ICADE 2027	-3.71	-7.81	×	-3.52	-10.04	×
Lietuvos 2027	-17.92	-3.12	✓	-35.27	-5.80	✓

Data compiled March 5, 2018.
Table replicated from report titled "Green Bond Pricing in the Primary Market, July-September 2017." The sample comprises select green bonds issued during the third quarter of 2017. Baskets comprise select other bonds issued during the same period, meeting the researchers' criteria, where the use of proceeds is not stated as green. These serve as a proxy for how else the money could have been invested within the three-month observation period. One week includes five data observations, and one month includes 20 data observations.
Source: Climate Bonds Initiative and International Finance Corp.

"The secondary market is where investors are getting their value out of green bonds," Wilkins said, "with the spread tightening even more than in the primary, sometimes as much as 20 to 25 basis points ... versus non-green."

According to CBI data, **green bonds are generally outperforming indices**, with 79% tightening more than their corresponding index seven days after announcement date. That **may help draw more "traditional" investors**, i.e. those attracted for monetary, rather than environmental, reasons.

"If you invest in a green fund, the fund may pay slightly more to purchase an instrument. However, the fund also has the opportunity to potentially sell it also at a slight premium," said Tom Kinmonth, a fixed-income strategist at ABN AMRO.

In addition, NatWest Markets has found that green bonds can create a "halo effect" for an issuer, pushing down yields across their bond portfolio.

'Halo effect' of issuing green bonds

Spreads on bond portfolios of green bond issuers vs. similar non-green bond issuers

	Rating				Bond portfolio		Replicating portfolio*	Green halo value**
Issuer group	Moody's	S&P	Sector	Country	Tenor (years)	Spread (bps)	Spread (bps)	(bps)
TenneT Holding BV	A3	A-	Utility	Netherlands	7.0	9	18	9
Enel SpA	Baa2	BBB+	Utility	Italy	7.5	29	36	7
Engie SA	A2	A-	Utility	France	7.6	18	20	2
Unibail-Rodamco SE	NR	A	Real Estate	France	7.4	17	20	3
Orsted AS	Baa1	BBB+	Utility	Denmark	8.0	21	34	13
Icade	NR	BBB+	Real Estate	France	6.5	39	41	2
Ferrovie dello Stato Italiane SpA	NR	BBB	Infrastructure	Italy	5.8	43	47	4

Data compiled March 5, 2018.
* Replicating portfolios comprise bonds from seven issuers in the same sector that have not issued a green bond. They are constructed to match as closely as possible the issuer's bond curve in terms of tenor, rating, sector, geography and CSPP eligibility.
** Green halo value is the spread difference between the bond portfolio of the green bond issuer and the replicating portfolio from companies that have not issued green bonds.
Spread = spread over midswaps; bps = basis points
Source: NatWest Markets

Premiums could set trend

Scharfe said future pricing will depend on how quickly investors shift their preferences. "This is normal evolution in a market which is nascent and just needs to find its solid base," he said.

The current price premiums could set a trend, though, with existing green bonds beginning to serve as a reference point for new bond pricing.

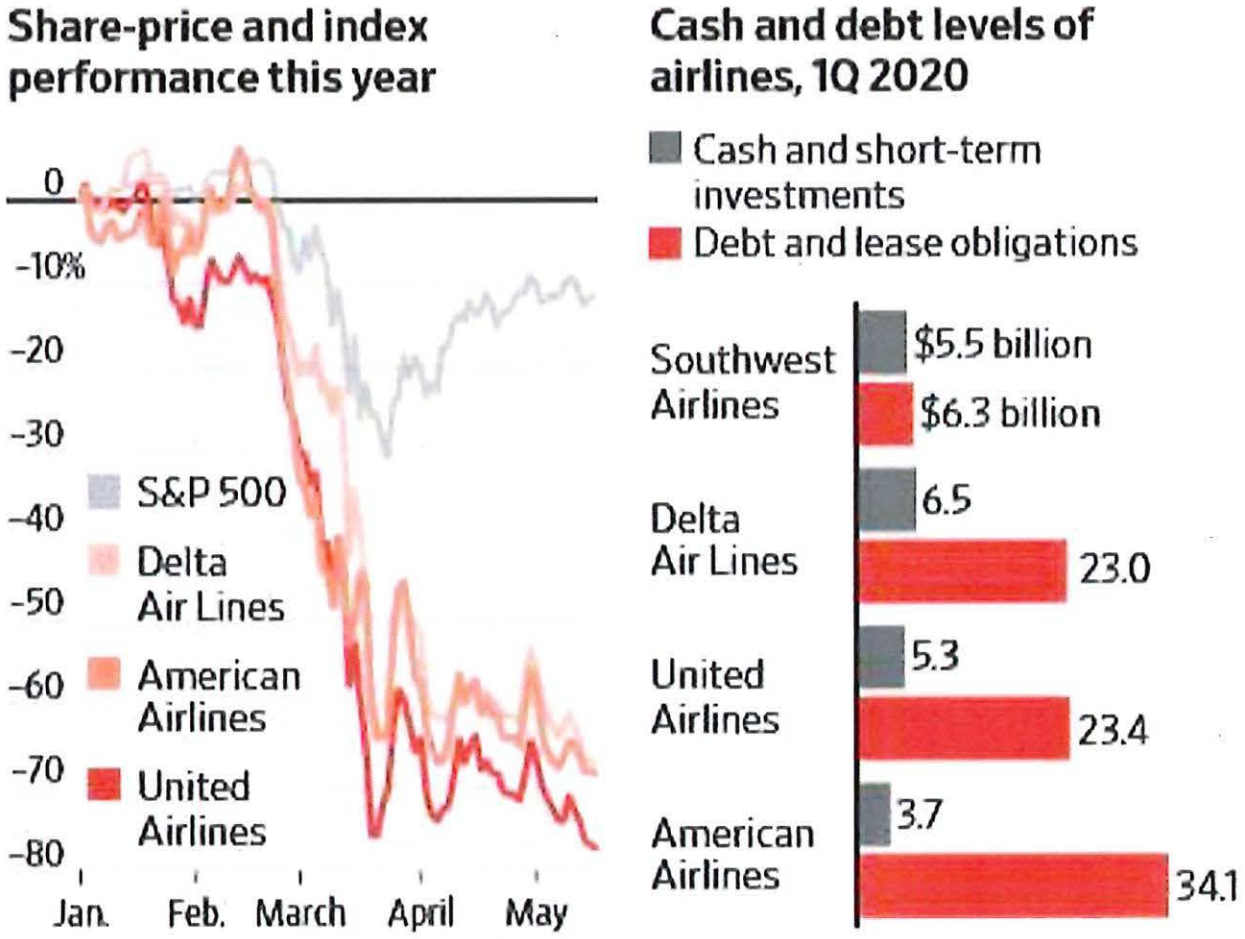
"If green bonds were trading tighter than vanilla bonds, we would reasonably expect to see a consistent greenium emerging," Climate Bonds Initiative said.

Pricing may also change as investors take into account the environmental benefits of a green bond issue, S&P Global Ratings' Wilkins said.

"The pricing of green bonds does not correlate with the environmental impact being provided by the green bond and that is something we think will change over time," he said. "You usually see a correlation between the credit spread and the credit rating so the higher the rating, the smaller the spread to reflect risk or lack of risk. At the moment that spread advantage is not correlated to the greenness of the bond."

Investors Struggle for Insight As Companies Toss Forecasts

by Karen Langley – WSJ – May 18, 2020



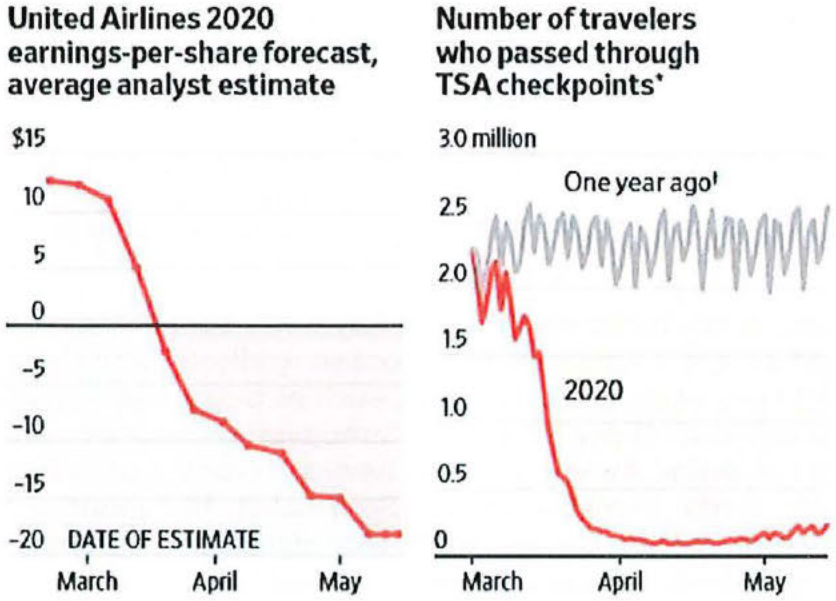
Sources: FactSet (performance); Company quarterly reports (cash and debt levels)

Stocks have bounced off their March lows but remain stuck in a relatively narrow trading range while investors grapple with an **unprecedented lack of visibility** on the **economic outloo**k. Even those interested in jumping back into the stock market to hunt for bargains face a tall order: **How can you value stocks when** it remains **unclear how quickly** the **economy will bounce back** and **whether consumer behavior** will **change when it does**? The nearly completed earnings season offered little clarity because **many companies** were **unable** to **forecast what** the **future holds**.

For some of the **most beaten-down stocks**, **including** those of **airlines**, the **outlook** is **particularly murky**. The carriers have lost billions of dollars since the coronavirus pandemic brought travel to a near halt in mid-March. And even once they resume a busier schedule, many people may be reluctant to travel.

"2020 earnings are completely out the window," said Dan Eye, head of asset allocation and equity research at Roof Advisory Group, a division of Fort Pitt Capital Group. "I think this year is really **all about survival**."

That means **investors can't rely on** a **traditional playbook**. **Past earnings don't matter**, **revenue has plummeted**, and there is **no indication when demand will pick up**. On United Airlines Holdings Inc.'s recent conference call, Chief Financial Officer Gerald Laderman said of **earnings per share** and **margin growth**: "**Such metrics simply aren't relevant today**."



*As of Thursday †Same weekday
Sources: FactSet (EPS forecast); Transportation Security Administration (travelers)

Investors who just months ago were scrutinizing projections for growth are now turning to measures of survival, such as cash burn and debt loads. The same considerations apply to companies in other industries turned upside-down by the pandemic, from retailers to energy companies to cruise lines.

This week, investors trying to gauge the economic outlook will get a fresh look at the retail sector as Walmart Inc., Home Depot Inc. and Target Corp. report quarterly results. The investors will also parse the minutes of the most recent Federal Reserve meeting.

In this year's battered stock market, airline shares have been among the hardest hit, with **United down 77%**, **American Airlines** Group Inc. **down 68%**, **Delta** Air Lines Inc. **down 67%** and **Southwest Airlines** Co. **down 56%**. In **comparison**, the **S&P 500 is off 11%.**

The **stocks got** a **prominent vote of no confidence** earlier this month when **Warren Buffett said Berkshire Hathaway** Inc. had **sold** the **entirety** of its **airline holdings**. **Boeing** Co. Chief Executive **David Calhoun added more fuel** to the **fire** last week, **warning** the **airline industry** is having an "**apocalyptic**" **moment** that **could force** a **major carrier out** of **business**.

Just a **few months ago**, **airline investors focused** on such **metrics** as **capacity growth** and **added revenue from charging for seats**, along with **fuel** and **other**

costs, said Matthew Moulis, portfolio manager of the Fidelity Select Air Transportation Portfolio and the Fidelity Select Transportation Portfolio.

Now investors have turned their **focus** to **how quickly companies** are **spending cash** and **how easily** they **can access more**. **American** has said it expects to **burn** through some **$70 million in cash a day** in the current quarter, while **United** has estimated its **daily cash burn rate** at **$40 million** to **$45 million**.

Airlines have also **turned** to the **capital markets** – and a **government rescue—for funding**.

Among other moves, **United** and **Southwest** unveiled plans for **stock offerings**, with **Southwest also offering convertible notes**, while **Delta tapped** the **bond market**. A **$25 billion government package** was designed to help the airlines meet payroll.

Savanthi Syth, equity research analyst at **Raymond James Financial** Inc., recently **analyzed** airlines' cash levels and undrawn revolvers, along with estimates for ticket refunds, debt payments and other costs, such as payroll, lease payments, landing fees and interest expense. **If demand doesn't recover** and **workers aren't furloughed**, she **estimated American** would have **six months** of **cash on hand**; **United**, **10** months; **Delta**, **11.3 months**; and **Southwest**, **18.7 months**. (The calculations don't include loans through the federal stimulus.) Investors in the sector are increasingly trying to identify potential winners and losers.

At Roof Advisory, which has a small position in Delta, Mr. Eye said he believes Southwest is in a stronger position than its peers. The discount carrier had $6.3 billion in debt and lease obligations on its balance sheet as of March 31, while American had $34 billion. Southwest reported $5.5 billion in cash and short-term investments, compared with $3.7 billion for American, which also had $3.2 billion in undrawn credit at that time.

"Southwest looks to be in a pretty good liquidity position and also carrying really low leverage, even after some of the recent cash raises and government grants," Mr. Eye said . "On the other side of the coin would be American. They were highly leveraged even before the pandemic."

A representative for American pointed to the company's earnings call last month, when Chief Executive Doug Parker said its liquidity position is strong. The company said at that time that it raised $2 billion in the first quarter in debt and by selling planes and leasing them back.

Investors and analysts are also watching interest obligations and cash flows. Hunter Keay, senior analyst at Wolfe Research, **questioned whether** the **carriers can generate enough cash** and **earnings** to **cover** the **interest** on the **debt** they raised to get through the crisis, even if demand does recover.

Meanwhile, Delta Chief Executive Ed Bastian said last week that the airline had refunded more than $1.2 billion to customers since the pandemic began. Such requests are pressuring cash flows across the industry. That is a critical metric to watch, said

Helane Becker, senior research analyst at Cowen, because **airlines** are a **short-term cash business**, with **most tickets purchased within 90 days** of **travel**.

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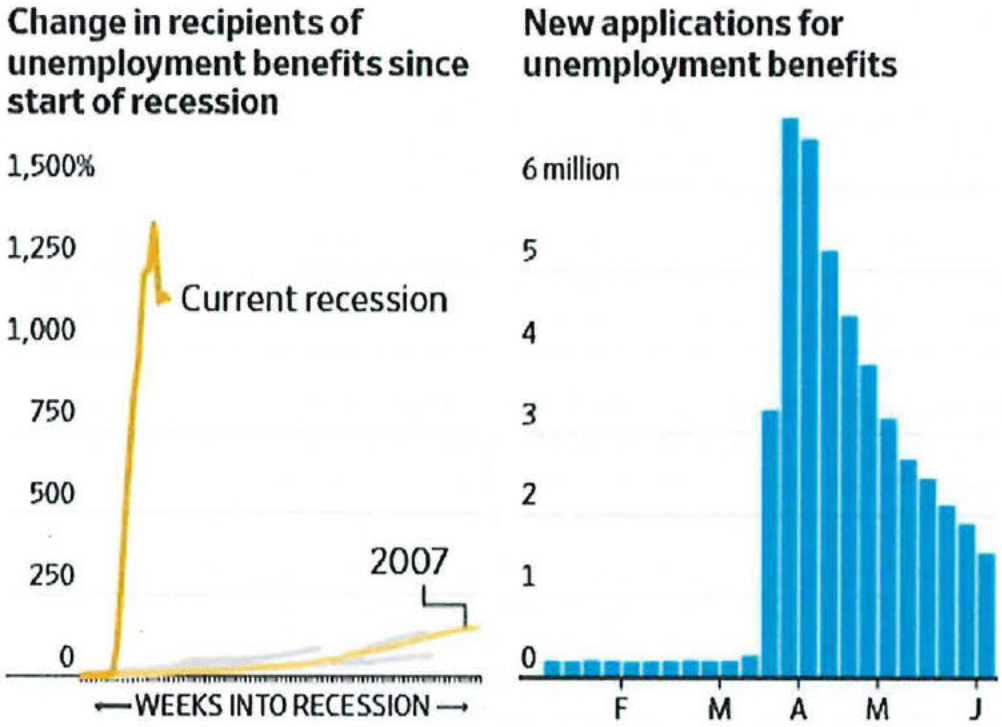
Jobless Claims Reflect a Slow Mend

by Sarah Chaney and Kim Mackrael – WSJ – Jun. 12, 2020



The number of people seeking unemployment benefits continued to fall while those receiving them appeared to plateau, signs the U.S. labor market continues to slowly mend from the coronavirus employment shock.

The ranks of **Americans drawing on unemployment benefits declined slightly** in the **week ended May 30 to 20.9 million**, the Labor Department said Thursday. So-called continuing claims remain historically high – the **prepandemic record was 6.6 million in 2009** – and appear to have stabilized in recent weeks after peaking in early May.

Though states continue to work through a backlog of claims, new applications for unemployment benefits have trended down since the pandemic and related lockdowns triggered a surge in claims at the end of March. About **1.5million applications** were **filed last week**, **compared** with a **peak** of nearly **seven million** in the **week ended March 28**.

"It's fair to say that the **recovery** has **started**, but that's **not** a **guarantee** that the recovery will continue **uninterrupted**," said Daniel Zhao, senior economist at job site

Glassdoor. He pointed to the **possibility** of a **second wave of coronavirus infections** and a pullback in government aid as potential roadblocks to a smooth recovery.

Initial unemployment claims were down in just over half of states last week. States including Florida, Georgia and Texas saw large weekly declines.

Continuing claims, which are released with a one-week lag, fell in 34 states at the end of May.

Federal Reserve Chairman Jerome Powell on Wednesday played down recent positive news on the labor market, citing the long-term disturbances the pandemic is causing for the economy.

"I think we have to be honest, that it's a long road," he said.

New data released separately by the Fed showed the net worth of U.S. households fell sharply in the first quarter as the pandemic sent shock waves through the economy and caused equity prices to plummet.

Household net worth fell 5.6% in the quarter from the previous three months to a seasonally adjusted $110.79 trillion, the Fed said. Most of the decline was attributable to a $7.8 trillion drop in the value of directly and indirectly held corporate equities, the central bank said.

As businesses reopen and some recall workers who were furloughed, the labor market appears to be picking up after millions of jobs were lost in March and April. Although unemployment is still at levels unseen in many decades, the jobless rate in May declined to 13.3%, and employers added 2.5 million jobs that month.

Policy debates over the pace of economic recovery are at the heart of discussions regarding the next virus stimulus bill. Democrats want to extend he extra $600 a week that jobless claimants are receiving as part of a federal stimulus bill passed in late March, arguing that if businesses don't rebound quickly, the additional money will keep millions of workers afloat financially. Republicans are concerned that the supplemental benefits will discourage people from returning to work, slowing the economic recovery.

The **expanded benefits** are scheduled to **expire** at the **end** of **July**.

Meanwhile, workers are still facing delays in accessing benefits. A recent survey by job search company ZipRecruiter found more than a third of individuals who applied for unemployment benefits after losing their jobs because of the pandemic were still waiting to receive payments.

The survey was conducted June 1-4 and included 757 people who applied for benefits because of the pandemic and had logged into the job search site.

JP Morgan Top Debt Underwriter in Utility Sector for First Half of 2020

by Darren Sweeney and Anna Duquaitan
S&P Global Market Intelligence – Jul. 13, 2020

J.P. Morgan Securities LLC held onto its crown as the **North American utility** sector's **top debt underwriter** through the **first six months of 2020** in an S&P Global Market Intelligence ranking by deal credit.

J.P. Morgan served as a **book manager** for **44 debt offerings** with a total deal credit of about **$5.83 billion** through June 30. **Wells Fargo** Securities LLC and **Bank of America** Securities **each** served as **underwriters for 34 debt offerings** in the utility sector during the first half of 2020.

Wells Fargo's offerings had a total deal credit of about $4.25 billion, while Bank of America's offerings totaled about $4.02 billion.

Mizuho Securities USA LLC served as a book manager for 46 debt offerings in the sector with a total deal credit of $4 billion.

PG&E Corp. subsidiary Pacific Gas and Electric Co. in June sold $8.93 billion worth of first mortgage bonds to help the utility and its parent company finance their joint Chapter 11 restructuring plan and bankruptcy exit.

J.P. Morgan, Barclays Capital Inc., Bank of America Securities, Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, BNP Paribas Securities Corp., Credit Suisse (USA) Inc., Mizuho Securities, MUFG Securities Americas Inc. and Wells Fargo acted as joint book-running managers.

There were **significantly less common equity offerings among U.S. and Canadian utilities** for the **first half of 2020**, according to S&P Global Market Intelligence data.

Citigroup Global Markets topped the list, serving as a book manager for three common equity offerings at a total deal credit of about $1.05 billion. Goldman Sachs also served as a book manager for three common equity offerings with a total deal credit of $1.02 billion.

Barclays Capital followed with two common equity offerings at a total deal credit of about $977 million.

On June 26, PG&E Corp. priced its public offerings of common shares and equity units for total net proceeds of more than $5 billion.

The company priced 423,372,629 shares of its common stock at $9.50 per share for gross proceeds of about $4.02 billion and 14,545,455 of its equity units at $100 per unit for gross proceeds of more than $1.45 billion.

Goldman Sachs and J.P. Morgan acted as joint lead book-running managers, while Barclays, Citigroup and Bank of America Securities acted as joint book-running managers for both offerings.

Utilities

2020 YTD rank	2019 rank	Company	Number of offerings	Deal credit ($M)
Common equity offerings *(Ranked by deal credit)*				
1	1	Citigroup Global Markets Inc.	3	1,053.0
2	5	Goldman Sachs & Co. LLC	3	1,020.1
3	3	Barclays Capital Inc.	2	976.9
4	7	Bank of America Securities	4	965.5
5	4	J.P. Morgan Securities LLC	2	847.6
6	NR	BMO Capital Markets Corp.	1	100.0
7	NR	Evercore Inc.	1	76.0
7	2	Wells Fargo Securities LLC	1	76.0
9	NR	HSBC Securities (USA) Inc.	1	43.2
10	6	Morgan Stanley	1	41.9
Debt offerings *(Ranked by deal credit)*				
1	2	J.P. Morgan Securities LLC	44	5,832.7
2	3	Wells Fargo Securities LLC	34	4,245.9
3	7	Bank of America Securities	34	4,021.7
4	4	Mizuho Securities USA LLC	46	4,002.7
5	1	MUFG Securities Americas Inc.	37	3,871.3
6	5	Barclays Capital Inc.	33	3,580.0
7	10	U.S. Bancorp Investments Inc.	33	3,150.7
8	6	Citigroup Global Markets Inc.	32	2,964.5
9	11	Scotia Capital Inc.	34	2,714.3
10	8	TD Securities (USA) LLC	29	2,557.6
11	13	RBC Capital Markets LLC	25	2,375.0
12	14	PNC Capital Markets LLC	22	2,012.2
13	9	BNP Paribas Securities Corp.	21	2,010.5
14	18	Goldman Sachs & Co. LLC	15	1,789.1
15	15	SMBC Nikko Securities America Inc.	23	1,726.7
16	12	Morgan Stanley	17	1,545.5
17	17	BB&T Capital Markets	10	1,124.7
18	24	KeyBanc Capital Markets Inc.	14	1,009.4
19	16	Credit Suisse (USA) Inc.	9	989.6
20	23	CIBC World Markets Corp.	11	775.9
21	20	Crédit Agricole Securities (USA) Inc.	7	677.0
22	19	Bank of New York Mellon Corp.	9	660.8
23	27	Fifth Third Securities Inc.	3	295.4
24	22	BMO Capital Markets Corp.	4	284.2
25	30	BBVA Securities Inc.	3	261.3
26	NR	Piper Sandler & Co.	2	160.0
27	29	Banco Santander SA	3	159.1
28	NR	Academy Securities Inc.	1	130.0
29	21	Deutsche Bank Securities Inc.	1	100.0
30	NR	Commerzbank AG	1	93.8
30	33	NatWest Markets Securities Inc.	1	93.8
32	39	UBS Investment Bank	2	70.5
33	26	Regions Securities LLC	1	70.0
34	34	Stephens Inc.	1	33.3

Key Fed Official Warns of Double Dip

by Nick Timiraos – WSJ – Jul. 15, 2020

A top official at the Federal Reserve said difficulty suppressing the new coronavirus will pose **substantial risks for** the **U.S. economy**, including a **possible double dip** in **economic activity**, and **warned** that the **nation faces** a **long, slow recovery even if those hazards** are **avoided**.

It is important for policy makers to recognize that the **economy will face headwinds for some time**, **Fed governor** Lael **Brainard said Tuesday**. "That calls for a sustained and comprehensive framework of accommodation."

Ms. Brainard said the **recovery in spending and hiring** in recent months was **due largely to** "**rapid** and **sizable fiscal support**," such as onetime relief payments and extra unemployment insurance benefits that are set to expire in the coming weeks.

"Fiscal support will remain vital," she said.

Data tracked by Fed economists suggest that **strong gains in hiring in May and June may not be sustained**, Ms. Brainard said. **Coronavirus infections** have **accelerated** in **several large states since mid-June**, when the Labor Department conducted its most recent survey of payroll growth.

The **economy** added 7.5 million jobs in May and June but **still has 14.7 million fewer jobs than before** the **pandemic hit** the **U.S.**

"The recent resurgence in Covid cases is a sober reminder that the **pandemic remains** the **key driver** of the **economy's course**," she said. "A **thick fog** of **uncertainty** still surrounds us, and **downside risks predominate**."

Ms. Brainard cited a number of risks that could result in worse-than-expected economic growth, and she said she expected the recovery to face headwinds even if those downside risks don't materialize.

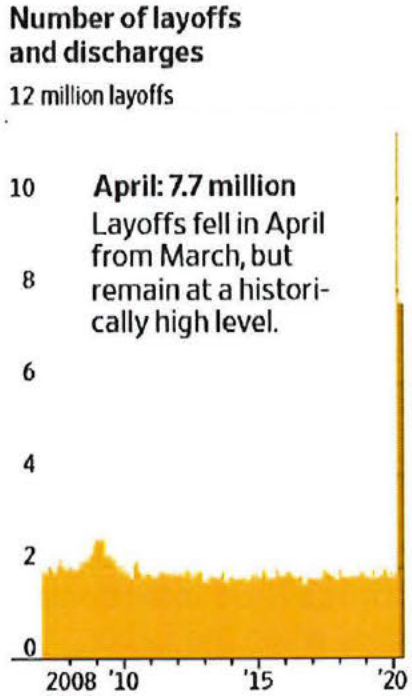
A second wave of infections, she added, would only "magnify that challenge."

Ms. Brainard is **one of five members** of the **Fed's board of governors** and has become an **ally of Fed Chairman Jerome Powell**. Her speeches on the economy are infrequent and her comments tend to carry weight within the Fed.

Ms. Brainard **said** with **interest rates now pinned near zero,** the most effective way for the **Fed** to provide further stimulus would be to deliver more concrete guidance about its **plans to keep rates near zero**.

Layoffs Fell to 7.7 Million in April

by Sarah Chaney – WSJ – Jun. 10, 2020



Note: Data are seasonally adjusted
Source: Labor Department

The pace of job losses eased in April, adding to the evidence that the initial surge in unemployment because of the coronavirus pandemic has cooled.

Layoffs declined to 7.7 million in April from 11.5 million in March, the Labor Department reported Tuesday.

The data come after the federal agency released unemployment figures for May showing the jobless rate declined last month, and the U.S. economy restored some jobs lost during the first two months of the pandemic.

"There were huge numbers of layoffs in the last two weeks of March," said Julia Pollak, labor economist at jobs website ZipRecruiter. "Once companies cut to the bone, there wasn't much more to cut."

Industries that were hit harder by the shutdowns to curb the spread of the coronavirus in March, including leisure and hospitality and retail, experienced fewer layoffs in April.

The number of April layoffs was still well above levels seen before the coronavirus and related lockdowns triggered widespread business closures in March.

Ms. Pollak said several industries experienced a rise in layoffs in April, including mining, construction and real estate, indicating the economic pain persists.

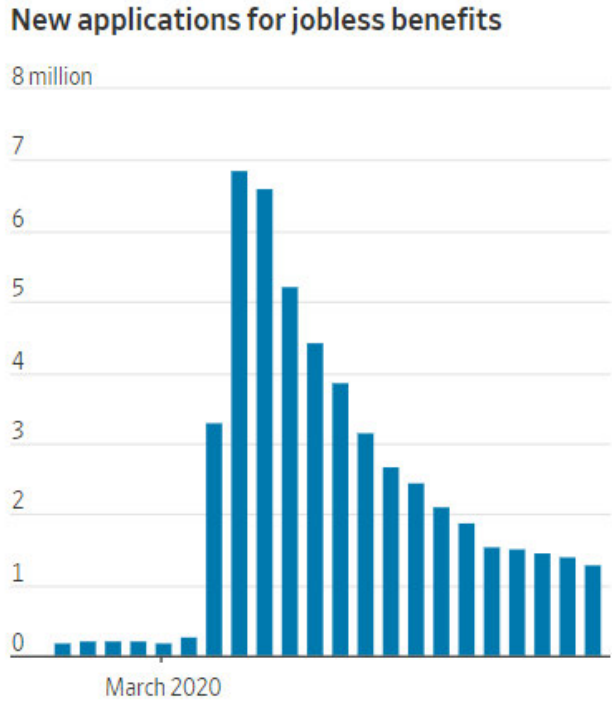
Workers appeared wary of leaving their jobs in April. The number of those quitting fell in April to 1.8 million from 2.8 million in March and 3.5 million a year earlier. "Anyone who has a job right now is going to stay in it, because there are so few outside opportunities," Ms. Pollak said.

Companies' appetite to hire workers remained weak in April. Job postings fell to five million, compared with six million in March and 7.3 million a year earlier. Hiring dropped to a record low.

The outlook for hiring strengthened in May. The Labor Department's May jobs report showed that while employment is down by nearly 20 million jobs compared with before the pandemic, employers added 2.5 million jobs that month.

U.S. Initial Unemployment Claims Edge Down in Latest Week

by Eric Morath and Kim Mackrael – WSJ – Jul. 9, 2020
Justin Baer contributed to this article.



Note: Seasonally adjusted
Source: Labor Department

ended June 27 to the lowest level since mid-April. Those so-called continuing **claims are reported with a week lag**. The modest easing of the number of unemployment rolls suggests new layoffs are being offset by hiring and recalling of workers.

Employers added a **combined 7.5 million jobs** in **May** and **June after shedding 21 million jobs** in **March** and **April**, separate Labor Department data showed.

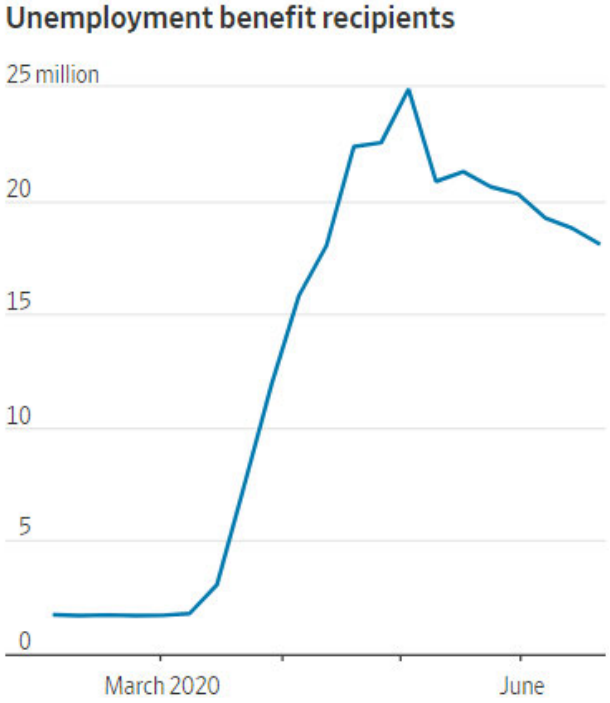
Claims fell in most states last week, including California and Florida, on a non-seasonally-adjusted basis, the Labor Department said. Claims did rise by 20,000 in Texas.

While Thursday's report is being watched for signs of how a rising level of

Initial unemployment claims edged down **to 1.3 million** in the **latest week** and **workers receiving benefits eased slightly to 18.1 million**, signs the labor market continues to heal.

The number of new applications for jobless benefits fell by a seasonally adjusted 99,000 for the week ended July 4, the Labor Department reported Thursday. That extends a trend of gradual declines from a peak of 6.9 million in mid-March, when the coronavirus pandemic and mandated business closures shut down swaths of the U.S. economy. **Still, last week's level** was **well above** the **highest week on record before this year**, which was **695,000 in 1982**.

The number of Americans receiving unemployment benefits fell for the week

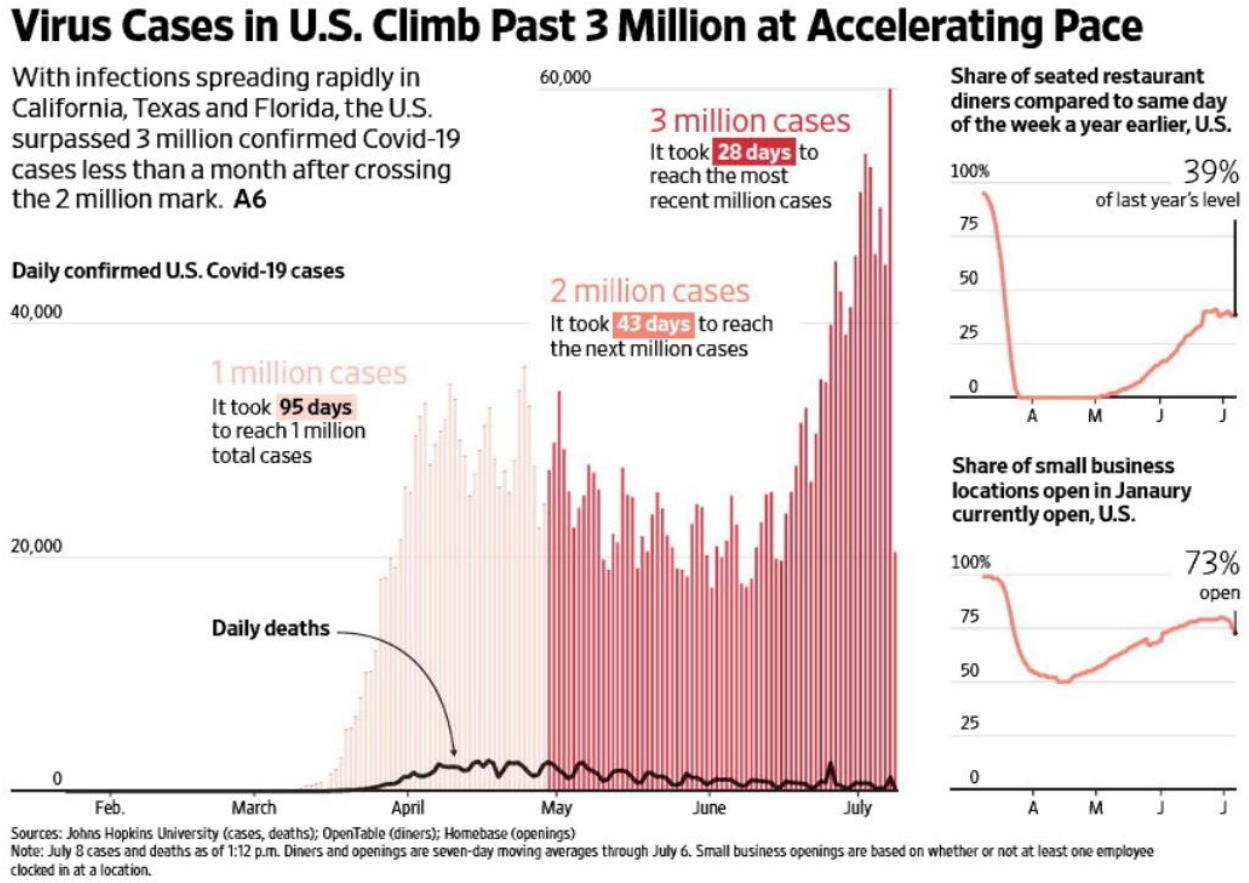


Note: Seasonally adjusted
Source: Labor Department

Covid-19 cases in several large states is affecting the labor market, it may not give a clear view.

The Independence Day holiday, observed July 3, reduced the number of business days applicants had to file. It isn't required for workers to seek benefits the same week they are laid off. Also, the seasonally adjusted data tend to be volatile around major holidays, because the timing differs slightly from year to year.

Whether that recent rate of job creation, and relatively lower pace of layoffs, can continue is in doubt because **coronavirus infections** are **causing state authorities** to **recalibrate reopening plans** and **creating renewed uncertainty** for many businesses and consumers.



Alyssa D'Angola, a 35-year-old bartender in Austin, Texas, lost her job at the Golden Goose for a second time in late June when the state ordered bars to close to stem a resurgence in coronavirus cases. She had only been back at work for five weeks when the second closure began.

Ms. D'Angola said she was able to delay her mortgage payments beginning in the spring and is receiving unemployment benefits, including a $600 weekly top up from the federal government. That extra benefit is set to expire at the end of this month. "When all this stuff runs out, I don't know where I'm going to be," she said.

Many economists, including Bradley Hardy at American University in Washington, D.C., expect overall employment growth will continue, but at a significantly slower pace than over the past two months.

"When you see the rising number of cases," he said, "you have to ask to what degree will that tamp down foot traffic and spending, and ultimately employment."

Several large employers have signaled future pullbacks.

United Airlines Holdings Inc. told 36,000 employees, about half its U.S. workforce, on Wednesday that they could be furloughed from Oct. 1 because of the pandemic-driven slump in passenger demand. Clothing retailer Brooks Brothers, which filed for bankruptcy this week, has permanently closed 50 stores due to the pandemic. McDonald's Corp. and Apple Inc. are among the companies that have halted plans to reopen stores or announced new temporary closures.

Still, some businesses are seeing a marked pick up and are recalling workers this summer.

Geoff Wolpert, owner of the Peddler Steakhouse and the Park Grill restaurants in tourism hub Gatlinburg, Tenn., laid off 138 of his 147 employees in late March, when the restaurants temporarily closed. About two-thirds of those workers were able to apply for unemployment benefits, he said. Mr. Wolpert also emptied the restaurants' freezers, making 180 seven-day food boxes for staff members.

The two restaurants reopened a week apart in late May. "I'm going to want to remember those for the rest of my life," he said of the reopening days. All employees were recalled, though 16 chose not to return.

After reopening, sales at the restaurants were initially half the previous year's amount, but in recent weeks, revenue returned to the 2019 level, he said.

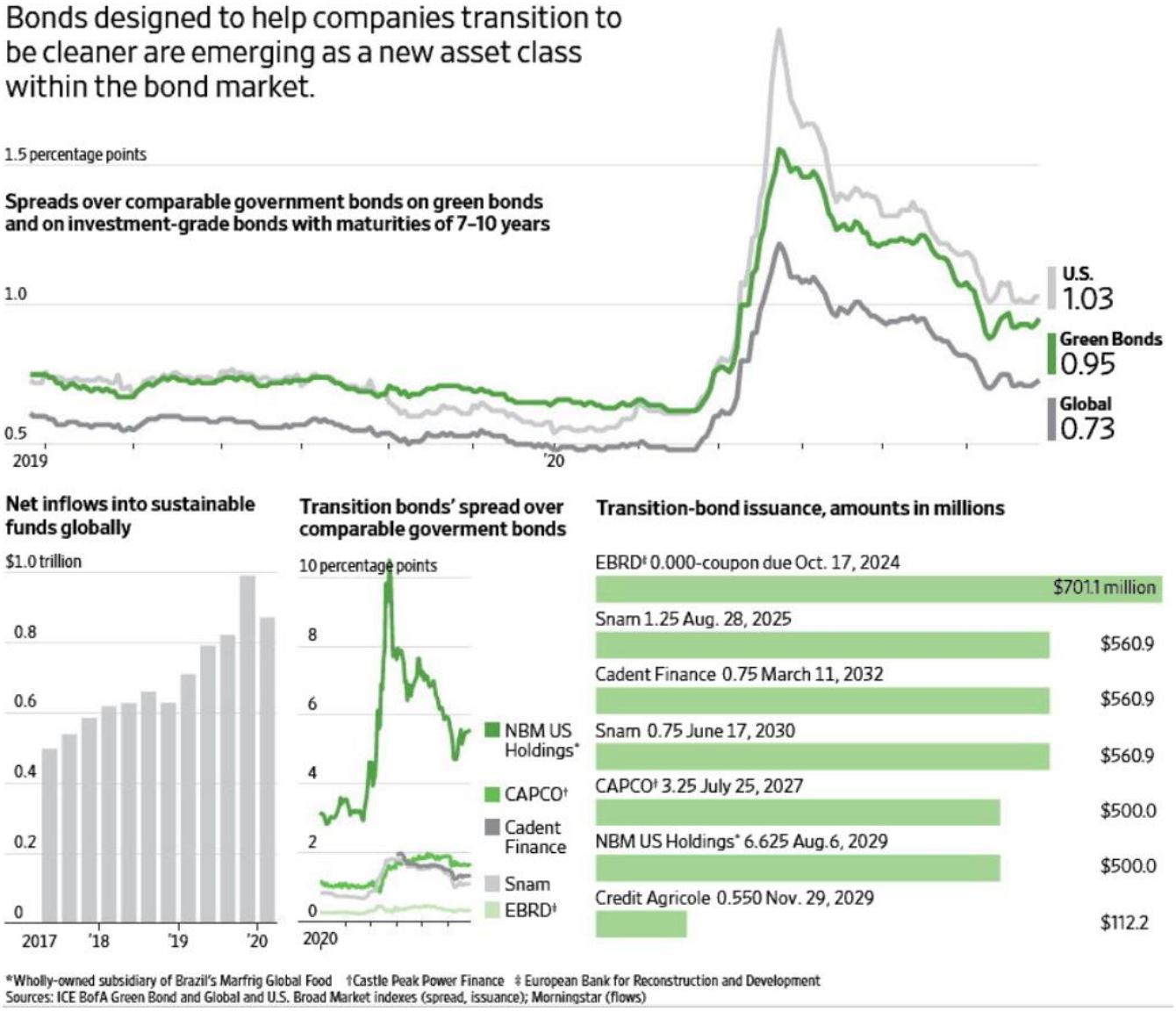
The bulk of hiring in recent months has come from businesses recalling workers to their former jobs, said Joaquin Alfredo-Angel Rubalcaba, an economist at the University of North Carolina. With all states at least partially lifting restrictions imposed this spring to limit the spread of Covid-19, he expects rehiring will contribute less to overall employment gains in the coming months.

Matching unemployed workers to new jobs will be a slower process, Mr. Rubalcaba said. Firms are likely to face increased costs for employee health benefits and unemployment insurance, and remain uncertain about the path of the economy, he said.

"We're attempting to confront a public-health crisis, but haven't been successful in doing that," Mr. Rubalcaba said. "That makes it hard to have a lot of confidence that the economy will continue to get better."

New Strategy Targets Climate Investors

by Anna Hirtenstein – WSJ – Jun. 29, 2020
Pat Minczeski contributed to this article.



When Cadent Gas Ltd. needed to replace parts of its pipeline network across England this year, it raised €500 million selling a new type of debt, known as **transition bonds**.

These bonds, worth $560 million, are being positioned as part of a do-good pool of investment opportunities that track **Environmental, Social and Governance** (**ESG**) benchmarks and have soared in popularity in recent years. But rather than being issued by companies that claim to have a high ESG score, transition bonds are designed for businesses that are still cleaning up their act.

As with other ESG investments, there are no hard-and-fast definitions or regulations to determine who raises the funds, and for what purpose. In general, the

transition bonds are meant to fund projects that make a company's operations more environmentally friendly, and help move toward developing a lower-carbon economy. Bankers, government officials and other stakeholders are trying to compile guidelines for this new asset class. Even a voluntary framework would help spur a boom by lending an element of legitimacy they say. The **market** for **transition bonds is nascent**, with seven transactions that have raised $3.5 billion so far, according to Bloomberg New Energy Finance. Recent issuers include Italian gas supplier Snam SpA, Brazilian meat processo Marfrig Global Foods SA and British gas network operator Cadent. **In contrast**, the **market** for **green bonds**, w**here the money is raised for environmental projects, drew** $268.8 billion last year.

"We are, at present, a company that transports methane, which is obviously a carbon gas. So we felt that we would have a bit of a credibility problem with some investors if we brought a transaction under a green framework," said Rob O'Malley, head of treasury at Cadent. Transition bonds are better suited for the business at this time, he said.

Whether this is a laudable evolution of sustainable finance is up for debate. Climate- change activists say investors and regulators should do everything possible to speed up the switch to a cleaner world, including offering incentives for polluters to change their ways. But some analysts question if it **skews the core values of sustainable finance too far** when funds earmarked by investors for environmental or social projects are used instead, for instance, for patching up a gas pipeline.

The coronavirus pandemic and resulting downturn has prompted a wave of bond sales as companies look to build up their cash as a buffer in more uncertain times.

Meanwhile, sustainable or socially responsible investing grew wildly popular in recent years, with both small and big investors who want to influence social change, the ecological impact of modern life or business ethics while also generating returns. The lack of oversight hasn't deterred investors, or the companies that have raised funds using their own, sometimes contradictory definitions of sustainable investment.

Billions of dollars have flowed into ESG-focused funds, **even through 2020's market volatility**. **By issuing green or transition bonds, companies** are able to **tap** the pockets of **fund managers** who have **mandates** to **buy sustainable investments**, said Anjuli Pandit, a banker at BNP Paribas.

Some investors and **activists** are **concerned** that **transition bonds** are a **way** for **companies** to **appear more environmentally friendly than they are**. Some issuers may use the funds raised to pay for routine upgrades, without trying to make significant changes to a company's carbon footprint, said Francesca Suarez, head of ESG research at Mirova, a responsible investing- focused fund manager owned by Natixis SA. "There's a **very strong risk of green-washing** that really needs to be paid attention to."

Cadent says the funds it raised in March with the transition bonds will be used to reduce methane leaks, a greenhouse gas that is a more potent contributor to global warming than carbon.

Meanwhile, the European Commission included transition projects in a June 2019 proposal for a sustainable-investment taxonomy. It suggests that they only be eligible for a green label if they are already low polluting – emitting 100 grams of CO2 per kilowatt- hour or less, in the case of power generation – and have the goal to reduce to zero emissions by 2050. Such stringent rules would exclude projects that transition bonds have financed so far, said Jonas Rooze, head of sustainability analysis at BNEF.

But a common standard will "make investors more comfortable and will probably push up demand," said Michelle Davies, head of Eversheds Sutherland's clean energy and sustainability practice. She has had conversations with companies working in consumer retail, fashion and pharmaceuticals about issuing transition bonds. "Covid has had a stalling impact, but all **signs are that investor interest remains firmly focused on all things ESG**," Ms. Davies said.

NextEra's Spending on Renewable Energy Resources Blows Past Other Utilities

by Michael Copley – S&P Global Market Intelligence – Jun. 23, 2020

NextEra Energy Inc. plans **to spend** about **$30 billion through 2022** on **renewable energy** resources like this wind farm in Texas.

NextEra Energy Inc. plans to invest more money annually in renewable energy in the next several years than most utility companies' total spending over that period, analysts at CreditSights said June 18.

Of the $52.5 billion of capital expenditures NextEra is expected to make in a four-year period through 2022, 57%, or $30.06 billion, is earmarked for renewables, according to CreditSights. That comes to about **$7.5 billion** in **annual spending** on **clean energy**, **most** of which will be deployed **through NextEra's unregulated** project development business, **NextEra Energy Resources** LLC, CreditSights said.

While **many utilities** are **making big investments** in **renewables** to take advantage of falling costs and to meet environmental and clean energy mandates, **none** come **close** to **NextEra** in terms of the **size of** the **investment** or the **share** of **total capital expenditures going** to **clean energy**.

"[We] believe the market opportunity for low-cost renewables has never been greater," **NextEra** Chairman, President and **CEO James Robo** said on an earnings call in April. By the mid-2020s, as battery costs continue to fall, "near-firm" wind and solar power is expected to be cheaper, without incentives, than most existing coal and nuclear power plants as well as less-efficient natural gas-fired generators, Robo said.

A NextEra spokesperson declined a request for an interview on the company's capital spending plans. John Ketchum, president and CEO of NextEra Energy Resources, which claims to be the top producer of wind and solar power globally, has said the company will leverage its scale to seize on new investment opportunities that are emerging due to the economic downturn caused by the coronavirus pandemic. NextEra is also aggressively adding to the solar portfolio at regulated utility subsidiaries Florida Power & Light Co. and Gulf Power Co.

NextEra Energy Inc. sells power from its Pinal Central Solar Energy Center in Arizona to the Salt River Project

Capital spending booms

Utilities are **charging ahead** with **capital spending plans despite slumping** electricity sales across much of the U.S., according to an analysis by Regulatory Research Associates, a group within S&P Global Market Intelligence. Executives said the investments are needed to maintain reliability and to capitalize on the shift to cheaper and cleaner energy resources.

For many utilities, investing capital through their **state-regulated businesses** is a way to generate reliable earnings even as some consider cutting costs to cope with falling demand.

Such **rate-based investments account** for about **half** of the **money utilities plan to spend on renewables** in the **coming years** as the companies increasingly opt for owning wind and solar plants rather than buying electricity from third parties, CreditSights said.

Dominion Energy Inc. **plans** to **invest $9 billion** in **wind** and **solar plants** and **energy storage** facilities **through 2023**, **35%** of **total capital** expenditures during that period, with the bulk put into rate base, according to CreditSights.

Executives at Dominion, which owns Virginia Electric and Power Co., doing business as Dominion Energy Virginia, recently told investors that the company increased the amount of money it expects to spend on renewables and energy storage after Virginia Gov. Ralph Northam signed the Virginia Clean Economy Act earlier this year. The law requires all of Dominion Energy Virginia's retail power sales to be carbon-free by 2045.

Berkshire Hathaway Energy, with electric utility operations in Iowa and seven western U.S. states, and Duke Energy Corp., with utility operations in five states, also stand out in the CreditSights analysis. **Berkshire Hathaway Energy** is **investing $5.5 billion**, or **32%** of its **capital budget**, in **renewables through 2022**, while **Duke** is devoting **$6.37 billion**, or **11%** of capital expenditures, **through 2024**.

Berkshire Hathaway Energy is **putting all** of its **renewable energy investments** into **rates** at **utilities including MidAmerican Energy** Co. **and PacifiCorp**, according to **CreditSights**, **while** about **two-thirds** of **Duke's will be rate-based**.

With utilities projected to invest close to $150 billion of capital in 2020, access to equity markets will be crucial for those spending plans, said Obioma Ugboaja, director of North American utilities at S&P Global Ratings.

Ore. PUC Staff Recommends Reduced Electric Rate Increase for PacifiCorp

by Charlotte Cox – S&P Global Market Intelligence Jun 10, 2020

The **O**regon **P**ublic **U**tility **C**ommission **staff and** other **intervenors filed testimony** in **PacifiCorp's** pending **rate case** June 4, with the **staff supporting** a **$7.2 million electric base rate increase**. The recommendation reflects a **9.0% r**eturn **o**n **e**quity (**52%** of **capital**) and a **7.0% overall return** (**Docket No**. **UE-374**).

The 9.0% ROE recommended by the staff is below the 9.72% average equity return accorded vertically integrated electric utilities nationwide in cases decided in the first three months of 2020 and the 9.73% average ROE in full year 2019, according to Regulatory Research Associates, a group within S&P Global Market Intelligence. For a discussion of trends in ROE authorizations and other rate case parameters, refer to RRA's Major Rate Case Decisions Quarterly Update.

PacifiCorp
Electric base rate case
Docket No. UE-374

	Rate change ($M)	ROE (%)	ROR (%)	Rate base value ($B)
Current case				
Requested by company	78.0	10.20	7.68	4.195
Recommended by PUC staff	7.2	9.00	7.00	NA
Previous case				
Requested by company	56.0	9.80	7.66	3.385
Settlement and PUC order	23.7	9.80	7.62	3.325

Compiled June 9, 2020.
ROR = rate of return, NA = not available
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

A **settlement conference** is scheduled for **June 18**. The PUC has transitioned its upcoming events to a phone-based format in response to the ongoing coronavirus pandemic. New rates are proposed to become effective Jan. 1, 2021.

This case was initiated Feb. 14, when **PacifiCorp** filed for a $78.0 million, or 6.0%, base rate increase in its **first general rate case filing** in **Oregon since 2013**. The company cited investments in renewable generation and transmission infrastructure, wildfire mitigation costs and investments in emissions control equipment installed at coal-fired facilities as the main drivers for its rate request.

The **requested** rate increase is premised upon a **10.2% return on equity** (**53.52% of capital**) and a **7.68% return** on an **average rate base valued** at **$4.195 billion** for a **test year ending Dec. 31, 2021**.

PacifiCorp noted that the net impact of its **request** would be **a $70.8 million rate increase** if the commission approves the use of separate riders to collect additional costs associated with the **closure of Cholla unit 4** in 2020 and refund deferred tax benefits associated with **federal tax reform**. The PUC previously authorized PacifiCorp to refund the 2018 tax reform deferral balance over a one-year period ending Jan. 31, 2020, and the 2019 deferral balance over the period spanning Feb. 1, 2020, through Dec. 31, 2020. Any remaining 2019 balance, as well as the 2020 deferral balance, were ordered to be included in the general rate case filing. The company proposed to implement a **wildfire mitigation** cost recovery mechanism, which would recover future capital expenditures related to wildfire **prevention**.

In addition, PacifiCorp proposed to implement a generation plant removal adjustment rider, which recovers costs associated with the closure or removal of coal-fired resources – such as Cholla unit 4 – from PacifiCorp's fleet in between general rate cases. As part of the filing, PacifiCorp requested that the PUC issue exit orders for most of the company's coal-fired units, spanning from 2020 through 2029 in compliance with state legislation enacted in 2016.

As calculated by staff, reliance on the lower return versus that initially sought by PacifiCorp accounts for about $39.1 million of the $70.8 million revenue requirement difference between the $78.0 million rate hike initially requested by company and the $7.2 million hike recommended by the staff. While the staff-supported rate base value was not specified, it appears that the staff made only modest adjustments to the company-proposed rate base. Consequently, the remaining $38.8 million of difference largely stemmed from adjustments to net operating income, or NOI.

The **staff's** proposed NOI adjustments included **disallowances** associated with **wages and salaries**, in particular, **incentive compensation**. As noted by staff, it is **long-standing PUC policy** to **exclude 100% of officers' bonuses**, which are typically based on increased earnings and other "financial, business, and corporate goals" that "**primarily benefit shareholders**"; **50% of nonofficer incentives** if they are **based** on **nonfinancial metrics**; and **75% of nonofficer incentives** if they are **based** on **financial performance**. Other NOI adjustments pertained to pension costs, operation and maintenance expenses — including $**7.7 million** in **O&M savings attributable** to **advanced metering infrastructure** — and **travel costs**.

The **staff** expressed **concerns** with **PacifiCorp's proposed wildfire mitigation plan** and **associated cost recovery mechanism**, finding that the **company did not provide** a plan with **specific investments** that could be evaluated to determine whether enough risk would be mitigated to justify the cost. Additionally, the staff noted that PacifiCorp did not provide any data demonstrating the **effectiveness** and **cost prudence** of the **proposed system-hardening activities**, such as the **installation** of **covered conductors**. The **staff recommends** that an **independent third-party evaluator** would be useful in assessing the reasonableness of the plan and proposes that wildfire risk costs, along with **vegetation management**, be reviewed and recovered through a deferral rate mechanism.

The **PUC staff did not address** the **company's proposed coal adjustment rider** nor the exit orders.

In testimony filed June 4, the Alliance of Western Energy Consumers, or AWEC, **recommended** a **$15.8 million rate increase premised** upon a **9.2% ROE**. AWEC also argued that PacifiCorp should use a **rate base valuation date** of **Dec. 31, 2020**, because "including plant additions in rates which are not expected until a distant period in the future runs too far afield of the **known and measurable** and **used and us**eful **standards** to be appropriately considered in rates."

RRA notes that the **PUC generally relies on** an **average original cost-rate base** and **has allowed filings based on partially or fully forecast test periods**.

Additionally, AWEC recommended that the PUC deny PacifiCorp's proposed wildfire mitigation mechanism and instead require PacifiCorp to recover any related costs through a general rate proceeding.

PacifiCorp operates as Pacific Power in Oregon and is a subsidiary of Berkshire Hathaway Energy, which is privately owned by a consortium of investors, including Berkshire Hathaway Inc.

PacifiCorp Issues Largest Request for New Energy Resources in Company History

by Jeff Stanfield – S&P Global Market Intelligence – Jul. 7, 2020

PacifiCorp on July 7 issued a request for proposals for **thousands of megawatts** of **clean energy projects to connect to** its **10-state transmission system**.

Although the Berkshire Hathaway Energy subsidiary rushed to get state regulatory approvals in order to meet a July 6 deadline for issuing the widely anticipated solicitation, it missed that date by a single day. PacifiCorp has scheduled a bidder workshop for July 9 and bids are due Aug. 10. The company plans to notify bidders who are selected for its initial shortlist on Oct. 14 and is targeting Nov. 8, 2021, to execute agreements with the winners.

Most projects must be able to achieve commercial operation by Dec. 31, 2024. However, **pumped storage projects can submit offers with commercial operation dates beyond that deadline because they have longer lead times**, PacifiCorp said.

The company said it expects most proposals will be for wind and solar resources, but the "all-source RFP" is open to projects of "any variety of qualifying energy production," PacifiCorp said.

The company is already the largest regulated utility owner of wind power in the West, but it is aiming to significantly increase the amount of renewable energy resources available to serve customers in of its Pacific Power division in California, Oregon and Washington and its Rocky Mountain Power division in Idaho, Utah and Wyoming. PacifiCorp's transmission facilities extend across four other states in which it does not have customers in order to connect the utility with its generation facilities and customers.

To that end, PacifiCorp's action plan to implement its most recent Integrated Resource Plan outlines the **company's intention to add 1,823 MW** of **new solar** resources, **595 MW** of **new battery energy storage** and **1,920 MW** of **new wind** resources **by** the **end of 2023**.

The **2019 IRP's preferred portfolio** included nearly **3,000 MW** of **new solar** resources, more than **3,500 MW** of new **wind** resources and nearly **600 MW** of **battery storage** capacity combined with the new solar resources. **PacifiCorp V**ice **P**resident of Resource Planning **Rick Link** in a press release said the company aims for an **increasingly sustainable energy future**.

"Our all-source RFP is a catalyst to help realize that future and enable our customers and communities across the West to benefit from lower-cost renewable energy to grow their economies, run their businesses and homes," Link said.

Personal Income and Outlays Decline: April 2020
US Bureau of Economic Analysis (BEA) – Released May 28, 2020
https://www.bea.gov/news/2020/personal-income-and-outlays-april-2020

Personal Income increased $1.97 trillion (10.5 percent) in **April** according to estimates released today by the Bureau of Economic Analysis (tables 3 and 5).

Disposable Personal Income (**DPI**) increased $2.13 trillion (12.9 percent), and

Personal Consumption Expenditures (**PCE**) **decreased** $1.89 trillion (**13.6 percent**).

Real DPI increased 13.4 percent in April, and

Real PCE decreased 13.2 percent (tables 5 and 7).

PCE price index decreased 0.5 percent (table 9). Excluding food and energy, the PCE price index **decreased** 0.4 percent.

Coronavirus (COVID-19) Impact on April 2020 Personal Income and Outlays

The April estimate for personal income and outlays was impacted by the response to the spread of **COVID-19**, as federal economic **recovery payments** were distributed, and governments continued with "**stay-at-home**" **orders**. The **full economic effects** of the **COVID-19 pandemic cannot be quantified** in the **personal income** and **outlays estimate for April** because the **impacts** are **generally embedded** in **source data** and **cannot be separately identified**. For more information, see the "highlights" file and the Effects of Selected Federal Pandemic Response Programs on Personal Income table.

	2019	2020			
	Dec.	Jan.	Feb.	Mar.	Apr.
	Percent change from preceding month				
Personal income:					
Current dollars	0.2	0.6	0.5	-2.2	10.5
Disposable personal income:					
Current dollars	0.2	0.6	0.5	-2.1	12.9
Chained (2012) dollars	-0.1	0.5	0.4	-1.8	13.4
Personal consumption expenditures (PCE):					
Current dollars	0.4	0.4	0.2	-6.9	-13.6
Chained (2012) dollars	0.1	0.3	0.1	-6.7	-13.2
Price indexes:					
PCE	0.3	0.1	0.1	-0.2	-0.5
PCE, excluding food and energy	0.2	0.2	0.1	0.0	-0.4
Price indexes:	Percent change from month one year ago				
PCE	1.6	1.8	1.8	1.3	0.5
PCE, excluding food and energy	1.6	1.7	1.8	1.7	1.0

The increase in personal income in April primarily reflected an increase in government social benefits to persons as payments were made to individuals from federal economic recovery programs in response to the COVID-19 pandemic (table 3). For more information, see "How are the economic impact payments for individuals authorized by the CARES Act of 2020 recorded in the NIPAs?"

The $1,662.1 billion decrease in real PCE in April reflected a $758.3 billion decrease in spending for goods and a $943.3 billion decrease in spending for services (table 7). Within goods, decreases in all subcomponents were led by a decrease in food and beverages. Within services, the largest contributors to the decrease were spending for health care as well as food services and accommodations. Detailed information on monthly real PCE spending can be found on Table 2.3.6U.

Personal outlays decreased $1.91 trillion in April (table 3). **Personal saving** was $6.15 trillion in April and the **personal saving rate** – personal saving as a percentage of disposable personal income – was 33.0 percent (table 1).

Upcoming Annual Update of the National Income and Product Accounts

BEA will release results from the 2020 annual update of the National Income and Product Accounts on July 30, 2020, in conjunction with the advance estimate of GDP for the second quarter of 2020. For estimates of real GDP and its major components, the span of the update will cover the most recent five years (2015-2019) and the first quarter of 2020. Estimates of income and saving will be subject to revision from 1999 through the first quarter of 2020. More information on the 2020 annual update is included in the May *Survey of Current Business* article, "GDP and the Economy."

Updates to Personal Income and Outlays

Quarterly Census of Employment and Wages Included – Fourth Quarter of 2019

This release includes revised estimates of wages and salaries, personal taxes, and contributions for government social insurance for October through December 2019 (fourth quarter). These estimates reflect the incorporation of new fourth-quarter data from the Bureau of Labor Statistics' Quarterly Census of Employment and Wages.

Estimates have been updated for October 2019 through March 2020. Revised and previously published changes from the preceding month for current-dollar personal income, and for current-dollar and chained (2012) dollar DPI and PCE, are shown below.

	Change from preceding month							
	February				March			
	Previous	Revised	Previous	Revised	Previous	Revised	Previous	Revised
	(Billions of dollars)		(Percent)		(Billions of dollars)		(Percent)	
Personal income:								
Current dollars	104.6	104.0	0.6	0.5	-382.1	-413.8	-2.0	-2.2
Disposable personal income:								
Current dollars	87.9	88.2	0.5	0.5	-334.6	-349.0	-2.0	-2.1
Chained (2012) dollars	66.5	68.2	0.4	0.4	-261.8	-280.9	-1.7	-1.8
Personal consumption expenditures:								
Current dollars	26.8	31.5	0.2	0.2	-1,127.3	-1,031.7	-7.5	-6.9
Chained (2012) dollars	12.8	18.2	0.1	0.1	-983.9	-902.7	-7.3	-6.7

Pipeline Canceled Following Years of Delays

by Katherine Blunt – WSJ – Jul. 6, 2020

Dominion Energy to sell rest of its **natural-gas network to Buffett's Berkshire** for **$9.7 billion.**

Dominion and Duke had **first proposed** the **Atlantic Coast Pipeline** in **2014**. The builders of the Atlantic Coast Pipeline are pulling the plug on the project as companies continue to meet mounting environmental opposition to new fossil-fuel conduits.

Duke Energy Corp. and Dominion Energy Inc. said Sunday they were **abandoning** the **proposed $8 billion pipeline** – which **aimed** to **carry natural gas 600 miles through West Virginia**, **Virginia** and **North Carolina** and **underneath** the **Appalachian Trail** – citing continued **regulatory delays** and **uncertainty**, **even after** a **favorable U.S. Supreme Court ruling last month**.

Dominion said it was **selling** the **rest** of its **natural-gas transmission** and **storage network** to **Warren Buffett's Berkshire Hathaway Inc**. **for $9.7 billion including debt**. The deal **includes** a **25% stake** in the **Cove Point liquefied natural gas export facility** in **Maryland**, **of which Dominion will remain** the **largest owner**.

"This announcement **reflects** the **increasing legal uncertainty** that **overhangs large-scale energy** and **industrial infrastructure development** in the **United States**," Dominion and Duke said in a joint statement. "Until these issues are resolved, the ability to satisfy the country's energy needs will be significantly challenged."

Utilities and pipeline companies have been trying to expand U.S. pipeline networks for more than a decade to take advantage of the bounty of oil and gas unlocked by the fracking boom. But many of the projects have encountered **intense opposition from landowners**, **Native American groups** and **environmental activists** concerned about climate change who want to keep fossil fuels in the ground.

The Keystone XL pipeline expansion to carry oil from Canada to the U.S. Gulf Coast remains unbuilt more than a decade after it was proposed by TC Energy Corp. The operator of the Dakota Access pipeline, Energy Transfer LP, completed the conduit to carry oil from North Dakota's Bakken Shale region to Illinois in 2017 after years of protests and delays.

The Trump administration has sought to make it easier for companies to build pipelines and other energy infrastructure, but the effort has failed to fast-track projects amid continued legal and regulatory challenges by opponents.

Dominion and Duke had first proposed building the **Atlantic Coast Pipeline** in 2014. It repeatedly faced legal challenges. Its **costs** had **swelled** to $8 billion before the companies decided to abort the plan.

"Duke and Dominion did not decide to cancel the Atlantic Coast Pipeline – the people and frontline organizations that led this fight for years forced them into walking away," said Michael Brune, the executive director of the Sierra Club.

The companies had scored a significant victory last month when the **Supreme Court ruled that it could cut under the historic Appalachian Trail**, which runs from Georgia to Maine. The court overturned a lower-court ruling that found the **U.S. Forest Service** didn't **have** the **authority** to **grant** a **special-use permit** that allowed for the development of that segment.

However, Duke and Dominion said Sunday that the ruling wasn't enough to mitigate an "unacceptable layer of uncertainty and anticipated delays" for the project. They cited a Montana court ruling last month that threw another roadblock in the path of the Keystone XL Pipeline as an example of the continued challenges such projects face.

That ruling, which related to a federal permit program for oil and gas pipelines, had the potential to also further delay the Atlantic Coast Pipeline, the companies said. The companies involved had together invested about $3.4 billion in the pipeline to date.

Duke, based in Charlotte, N.C., provides electric and gas service to more than nine million customers in the Carolinas, Midwest, Florida and Tennessee.

Dominion, based in Richmond, VA., provides electricity or natural gas to about seven million customers in 20 states. It will almost entirely exit from its gas-transmission business with the sale of its pipeline and storage assets to Berkshire Hathaway Energy.

As part of the deal, **Berkshire Hathaway Energy will acquire Dominion Energy Transmission**, **Questar Pipeline** and **Carolina Gas Transmission as well as** a **50% stake** in **Iroquois Gas Transmission System**.

Berkshire Hathaway Energy will also acquire 25% of **Cove Point LNG**, **one of six liquefied natural gas export facilities in** the **U.S. Dominion will retain** a **50% stake in** the **project**, with **Brookfield Asset Management owning** the **remaining 25%**.

Berkshire Hathaway Energy operates a **$100 billion portfolio** of **utility**, **transmission** and **generation businesses providing natural gas and electricity** to more than **12 million customers**. The **Dominion acquisition will add 7,700 miles** of **natural- gas storage** and **transmission pipelines** and about **900 billion cubic feet** of **gas storage to** its **holdings**.

"Acquiring this portfolio of natural gas assets considerably expands our company's footprint in several Eastern and Western states as well as globally," **Bill Fehrman**, **Berkshire Hathaway Energy's president** and **chief executive**, said.

The **$9.7 billion transaction includes $5.7 billion in debt**. It is **expected** to **close** in the **fourth quarter**.

Dominion said the **sale** will **allow it** to **focus on** its **state-regulated gas and electric utilities**. It expects those businesses, primarily those serving Virginia, Ohio, Utah and the Carolinas will **account for** as much as **90% of future operating earnings**.

Dominion and Duke have each been pushing to slash their carbon emissions in response to state mandates and customer concerns about climate change. Both companies are **aiming for net-zero carbon emissions by 2050** by **developing more wind and solar power and investing in other clean technologies**.

Powell Sees Comeback as a Slow Process

by Nick Timiraos – WSJ – May 18, 2020

Federal Reserve **Chair**man Jerome **Powell said** the **U.S. economy could take more** than a **year to recover from** the **coronavirus-induced shock**.

"It's going to take a while for us to get back," Mr. Powell said in a rare television interview on CBS News's "60 Minutes" program. " The economy will recover. It may take a while … It could stretch through the end of next year. We really don't know."

Mr. Powell, who was interviewed Wednesday, said it was reasonable to think the unemployment rate would keep rising through June and then begin to decrease.

But he cautioned that the public would need to stay vigilant to avoid a second wave of infections. "That would be quite damaging to the economy and also to public confidence," he said. "That's a risk we really want to avoid."

He cautioned that it would be hard for the public to be "fully confident" until there is a vaccine for the new coronavirus. Economic activity that depends on large public gatherings, including entertainment and travel, could be especially challenged, Mr. Powell said.

In the interview, Mr. Powell challenged the idea that there is a trade-off between economic growth and protecting the public's health. "When the public is confident that it's safe to go out, they'll go out," he said. "That's why there's no trade-off here." The more that the public takes seriously social- distancing measures, "the sooner we can open up the economy," he said.

Measures to limit the pandemic have frozen much of commercial activity, leading to a sharp stop in economic output.

"This is a time of great suffering and difficulty, and it's come on so quickly and with such force that you really can't put into words the pain people are feeling and the uncertainty they're realizing," Mr. Powell said.

The **Fed responded aggressively** by **slashing rates** and **buying more than $2 trillion** in **Treasury and mortgage securities** to **stabilize financial markets**. It has **promised to lend trillions** of dollars **more**, **backed by** more than **$200 billion** in funds **from** the **Treasury** Department, **to support businesses** and **state** and **local governments**.

"We're not trying to move markets to a particular level," said Mr. Powell. "We just want them to work."

Puerto Rico Utility Sets Outsourcing Deal

by Andrew Scurria

An outsourcing agreement would involve a consortium operating and maintaining the territory's electricity grid.

Prepa's lines in Penuelas

Puerto Rico's bankrupt public power utility signed a long-term **deal** to **outsource** the business of **delivering electricity**, making an expensive bet that private operators can curb the high costs and service problems that have long plagued consumers.

The **U.S. territory's government- owned power monopoly** is **putting** a **consortium** of **operators including infrastructure contractor Quanta** Services Inc. in **charge** of **running** the **electricity grid for 15 years**, **hoping** they can **reverse years** of **mismanagement**.

The operators are inheriting challenges as they take over an **energy system crippled** by **years** of **underinvestment**, a legacy of **political interference** and **lasting damage** from the **2017 hurricane season**.

The deal marks a seminal moment for the **Puerto Rico Electric Power Authority,** which emerged as a crown-jewel public asset during and after World War II, powering the island's industrialization efforts and helping turn it into a manufacturing hub for pharmaceuticals and medical devices.

The utility, known as **Prepa**, **became less efficient over time**, **skimping** on **capital investments** while **piling up debt**. When **Puerto Rico** sank into **recession** more than a decade ago, **demand for power from industrial and residential customers declined**, stretching the utility's finances to the breaking point by 2014.

Putting the **consortium**— **Quanta** and its partners **ATCO** Ltd. and **IEM**—in charge of the grid will come at a cost, including a roughly **$60 million mobilization fee** during a yearlong transition period, people familiar with the matter said. In subsequent years, the operators will receive fixed **annual service fees** adding up to hundreds of millions of dollars over time, with the potential for **additional payments based on performance metrics**, one of the people said.

"We understand that electricity is not only about poles and wires and megawatts, it is the enabler of societies and economies," Wayne Stensby, president and chief executive of the consortium, said during a news conference announcing the agreement.

The **deal** would **maintain Prepa's ownership** of the **grid assets**, **easing** its **efforts** to **collect federal disaster relief money**.

Proponents of the agreement have said that installing private management at Prepa would help address reliability problems, stabilize the executive ranks and put an end to political interference in the utility's affairs. **Prepa** has been **plagued** by **frequent turnover at** the **top**, with high-level officials cycling in and out depending on the party in power, making long-term capital planning difficult.

The **utility** has **been under bankruptcy protection** for nearly **three years,** weighed down by roughly **$13 billion** in **bond** and **pension debt** and facing a **shrinking customer base**. **Power customers** from **manufacturers to households** have been exploring ways to **decouple from** the **utility**, **fed up with** the **cost** and **quality of service**.

Prepa needs to end its bankruptcy to realize the full benefits of the deal, which provides the operators with more favorable terms if the utility can't exit court protection for an extended period. But the **bankruptcy** is **far from over**. **Gov. Wanda Vázquez** and **other leaders have said** they **won't raise electricity rates** to **cover** a **proposed settlement with bondholders**, **leaving** **Prepa** with **no clear** path **back to solvency**.

Recession in U.S. Began in February

by Kate Davidson – WSJ – Jun. 9, 2020

Official declaration ends longest expansion on record; stocks climb on recovery optimism. The **U.S. officially entered** a **recession** in **February**, marking the **end** of the **128-month expansion** that was the **longest** in **records** reaching **back to 1854**.

While Monday's declaration by the **National Bureau of Economic Research** didn't come as a surprise to economists, the group typically waits until a recession is well under way before saying it has started.

But this time, the severity and breadth of the shutdown-induced downturn prompted it to break with past practice, "even if it turns out to be briefer than earlier contractions," the NBER's Business Cycle Dating Committee said.

Investors are betting on that outcome: The Dow Jones Industrial Average rose 461 points on Monday, up 1.7% and just 6.7% shy of its February highs. And after falling in early trading, the Nasdaq rose 1.1%, posting its first record close since February.

The probable duration of the recession is a matter of debate among economists and policy makers and is likely to influence discussions on the need for additional economic relief. Congress provided **$3.3 trillion** in **emergency spending and tax breaks** to support the economy, prompting some worries about a ballooning budget deficit.

Some policy makers, including Larry Kudlow, director of President Trump's National Economic Council, have predicted that consumer and business spending will bounce back quickly once social-distancing measures are lifted. Others, including Federal Reserve Chairman Jerome Powell, expressed concern about lasting economic damage.

Karen Dynan, a senior fellow at the Peterson Institute for International Economics and a former Treasury Department official, said that while the recession will likely be much shorter than the previous one in 2007-09, the aftermath could be similarly long and slow, given the severity of the shock.

"We fell into a gigantic hole, and even if we make substantial progress climbing out over the next few months, we're still probably going to be considerably in the hole," she said.

The nonpartisan **Congressional Budget Office said** last week the **U.S. economy** could take the better part of a **decade to fully recover**. **Gross domestic product** will **likely** be **5.6% smaller** in the **fourth quarter than** a **year earlier**, despite an expected pickup in economic activity in the coming months, and the unemployment rate could still be in double digits by the end of the year, the CBO said.

The agency has said the budget deficit is likely to hit $3.7 trillion in the fiscal year ending Sept. 30, fueled by stimulus spending and declining revenue.

February marked a break in the country's economic fortunes. The **unemployment rate** that month was **3.5%**, **matching** a **half-century low**.

In **March and April**, **employers shed** about **22 million jobs** as **social-distancing measures** kept consumers away from stores, restaurants and sports stadiums, and businesses shut down. By **April**, the **jobless rate hit 14.7%**, a **post-World War II high**.

There are tentative signs the economy might have hit bottom.

Employers added 2.5 million jobs last month, the **most** in a **single month** on **records** dating **from 1948**, and the **unemployment rate fell to 13.3%.** The unexpectedly strong report helped fuel Monday's stock-market gains.

Still, the **jobless rate remains** at one of the **high**est levels since the Great Depression, and **employment** is **down** by nearly **20 million jobs since February**.

By comparison, the U.S. shed about nine million jobs between December 2007 and February 2010, a period that encompassed the 18-month recession triggered by the financial crisis.

The **NBER**'s recession-dating committee looks at gauges of employment and production, as well as incomes minus government benefits, to determine when a recession has begun. It **doesn't use** the rule of thumb common elsewhere in the world: **two or more quarters** of **declining real gross domestic product**.

The **NBER considers February** the **peak** of the **business cycle**, when the **expansion ends** and the **recession begins**. The **month** in which the economy reaches its **trough** and **activity stops contracting marks both** the **end** of the **recession** and the **start** of a **new expansion**. The committee doesn't comment on how long the recession may last.

The current economic outlook depends on a range of factors, including the trajectory of the virus, the potential for recurring outbreaks and future shutdowns and economic aid from Washington. The White House and Congress are preparing to negotiate another round of stimulus measures.

Though it was the **longest** on record, the last expansion lacked the strength of previous ones, and was marked by **weak growth** and a **slow labor-market recovery**.

A **series** of **unprecedented government interventions** helped to **prop up growth for years**. The **Fed**eral Reserve **cut interest rates to zero** and **held them there for seven years** while **increasing** its **portfolio** of **bonds to $4.5 trillion**, **from less than $1 trillion**, in a bid **to** further **spur growth** by **pushing down long-term interest rates**.

Over a **three**-year **period beginning** at the **end** of **2015**, the **Fed raised** its **benchmark rate nine times** to a range between 2.25% and 2.5%, **before cutting rates three times last year** amid signs of a **global slowdown**. It slowly shrank its asset portfolio, to around $3.7 trillion last July.

Retail Sales Rebound by 17.7%

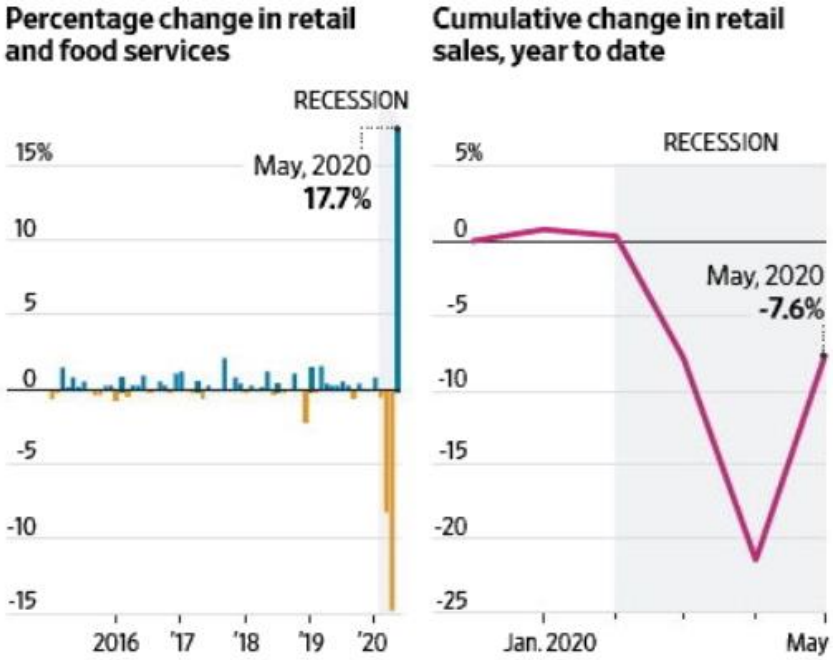
by Harriet Torry and Sarah Nassauer – WSJ – Jun. 17, 2020

May's record increase follows sharp drops, but spending is lower than before pandemic.

U.S. shoppers opened their wallets at malls and auto dealerships in May as states eased restrictions to contain the novel coronavirus, **boosting retail spending by 17.7%** and adding another sign the economy is recovering from earlier lockdowns to contain the pandemic.

The month-to-month, seasonally adjusted rise in retail sales was the **biggest increase in records dating to 1992** and **followed** the **largest monthly drop on record in April**, a revised **14.7% decline**, the **Commerce Department** said Tuesday. Separate data pointed to other signs of life in May for an economy that went into a deep freeze in March when the pandemic hit the U.S.

Still, retail spending last month remained below pre-pandemic levels, totaling $485.5 billion compared with $527.3 billion in February. **High unemployment** and a **wave of small-business failures** are seen **damaging** the **economy long-term**, **Federal Reserve Chairman Jerome Powell said Tuesday** at a Senate hearing.



Note: Seasonally adjusted
Sources: Commerce Department via St. Louis Fed (change in retail and food services); U.S. Census Bureau (cumulative change in retail)

From a year earlier, retail sales, a measure of purchases at stores, at restaurants and online, were down 6.1% in May.

Stock prices rallied on the retail-sales report. The S&P 500 gained 58.15 points, or 1.9%, capping off a third consecutive session of gains. The Dow Jones Industrial

Average climbed 526.82 points, or 2%, while the Nasdaq Composite added 169.84 points, or 1.7%.

The swing in retail sales reflected the nature of the shock from the pandemic, where the coronavirus and related lockdown shut off an economy that previously was growing at a steady pace—and re-openings restored at least some demand for goods.

"The big question going forward is to what extent does employment snap back to pre-crisis levels," a prerequisite for continued spending, said Joshua Shapiro, chief U.S. economist at MFR Inc. **May's unemployment rate** was **13.3%, down from 14.7%** the **previous month**, and **employers added 2.5 million jobs to payrolls**.

Retail executives said **government stimulus helped** boost their sales in the end of April and May, and they said continued spending will depend on the labor market's recovery.

"We've had a solid start to May in the U.S.," said Doug Mc-Millon, chief executive of Walmart Inc., the nation's largest retailer, discussing quarterly earnings last month. "But we believe stimulus spending has been a big driver, which we don't anticipate staying at these levels."

The government sent out **one-time stimulus payments** of as much as **$1,200 a person** in **April**, and it has separately provided financial help to businesses and workers. In addition, **unemployed workers** in **April** started **getting $600-a-week increases** in **unemployment benefits**. Those payments **expire** at the **end of July**, and congressional Republicans and the Trump administration have indicated they don't want to extend them.

The **Fed chairman told Tuesday's Senate hearing** that he **anticipates** the economy moving through three phases: shutting down, bouncing back, and **stabilizing at** a **level of activity** that is **lower than before** the **pandemic**.

"It's all quite uncertain but we appear to be entering that second phase of the economy reopening and businesses reopening and spending increasing," Mr. Powell said, citing May retail sales as "more evidence."

The Fed reported on Tuesday a moderate increase in May industrial production, including a pickup in manufacturing activity, following larger declines the prior month. A measure of builder confidence also improved.

The U.S. economy still has a long way to go to recover – economists project it could take years—and recent increases in coronavirus cases in more than a dozen states are casting a cloud over reopening efforts.

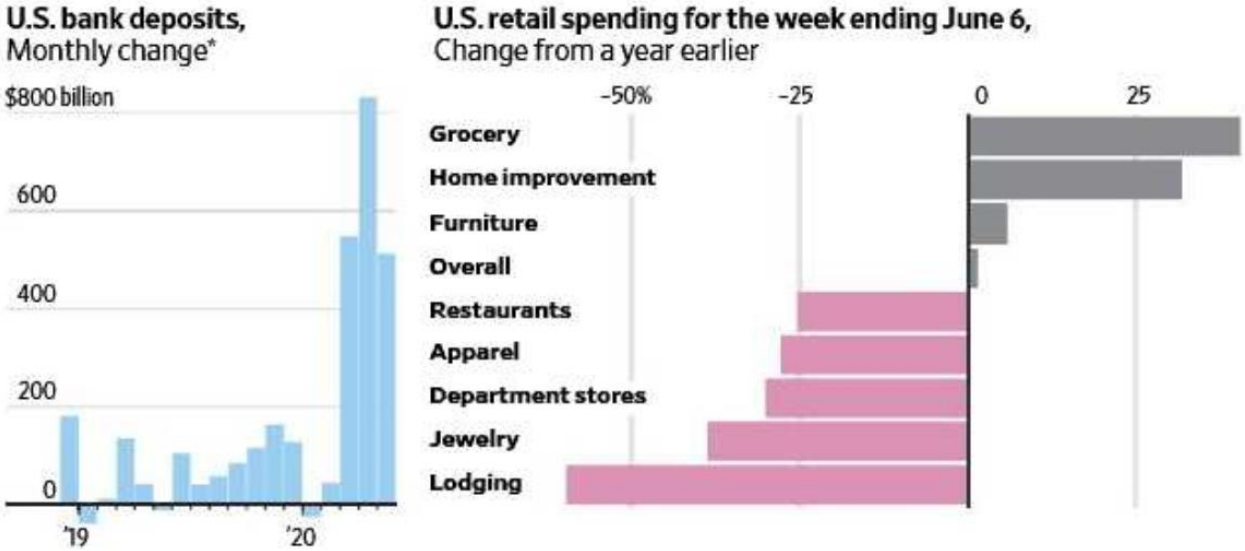
Consumer spending is the **main driver** of the **U.S. economy**, accounting for more than **two-thirds of economic output**, and **retail sales** account for about a **quarter** of **all consumer spending**. **Social distancing**, **lockdowns** and **travel restrictions** took an unprecedented **toll** on household spending in **March** and **April**.

Consumers increased their **outlays** across the board in **May**, though the increase was driven by a 44% month-over-month rise in spending on **motor vehicles**, which make up about a fifth of retail sales.

Furniture and **apparel** sales, which fell precipitously during coronavirus lockdowns, posted strong gains, with sales at clothing stores rising 188% from the prior month and furniture sales jumping 89.7%.

Focus on Home

Bank accounts swelled for many during lockdowns. Consumers are putting some of that extra cash into home improvements.



*All commercial bank deposits Sources: U.S. Federal Reserve; Mastercard SpendingPulse

Still, "the performance of individual sectors varies enormously," said Neil Saunders, managing director of Global-Data Retail. Department and clothing store monthly sales fell versus last year as many remained closed or partially closed. In addition, "**extensive discounting**, designed to clear down inventory, has also dampened sales values," Mr. Saunders said.

Receipts at **bars and restaurants jumped** nearly **30% in May from April but** were **down** nearly **40% year-over-year**.

Tuesday's report tracked spending on mostly goods, and not services such as health care and travel. The figures weren't adjusted for inflation.

As states allow businesses to reopen, there are signs consumers are ready to spend, at least a little. Shoppers flocked to a T.J. Maxx store in Ann Arbor, Mich., on Monday, many eager to see and touch clothes, jewelry and shoes.

Some shoppers said they are being cautious with spending, even though they are still employed.

"I've cut back a lot because the economy is the way it is," said Sue Vaandering, a 51-year-old from Brighton, Mich. She said she has been buying essentials such as food and household goods, and is starting to buy more summer supplies, but has been cutting back on clothes.

Rising Market Unsettles Skeptics

by Amrith Ramkumar and Michael Wursthorn – WSJ – Jun. 15, 2020

Doubters of stocks' advance are perplexed by the rally amid the economic downturn.

Many investors remain skeptical the stock market's powerful ascent can continue and are maintaining their **cautious** stances, a sign of lingering unease that could challenge the rally in the weeks ahead.

Some of these doubters have been bruised by the **S& P500's 18% climb this quarter** and are perplexed by what they deem a seismic disconnect between the

battered economy and roaring financial markets. Hopes for a swift economic recovery following coronavirus lockdowns and historic stimulus measures by the world's central banks have lifted stocks, pushing the technology-laden Nasdaq Composite to a record last week.

Yet cynics say there are plenty of reasons to remain cautious. These include projections for a bumpy economic recovery, setbacks to developing a coronavirus vaccine and uncertainty surrounding November's presidential and congressional elections. Those concerns dragged down markets last week, a rare slide in what has been a weeks-long surge.

In recent weeks, prominent investors including billionaire Jeffrey Gundlach of Double-Line Capital LP and Scott Minerd, the global chief investment officer for Guggenheim Partners LLC, have publicly called stocks overvalued, only for them to continue ripping higher. Money manager Jeremy Grantham wrote in a recent letter to investors, that "the current market seems lost in one-sided optimism." The Boston investment firm he co-founded, Grantham, Mayo, Van Otterloo & Co., said in the letter that it lowered its stockholdings in its flagship benchmark free-allocation strategy.

Despite the chorus of wary calls and last week's decline, the **S&P 500** is **up 36% from** its **March low** and **down just 5.9% for** the **year**, buoyed by tech giants including Microsoft Corp. and Facebook Inc.

"I'm just amazed with this rally. And frustrated," said Rob Almeida, global investment strategist at MFS Investment Management. "The speed has been so remarkable."

Mr. Almeida said MFS in April cut its equity exposure in its long/short strategy, the MFS Managed Wealth Fund, to its lowest level ever. The MFS Diversified Income Fund, meanwhile, has a bearish wager against the real-estate industry, using put options tied to the iShares US Real Estate ETF that expire in September. Puts allow the holder to sell an asset at a certain price by a certain date.

Investors in the coming week will look to Tuesday's retail sales report for May for signs that consumers are beginning to reopen their wallets. Earnings reports from software firm Oracle Corp. and home builder Lennar Corp. also are on tap.

Some analysts say the cautious positioning actually means stocks could have further to climb as more investors are drawn into the market. Investors are holding high levels of cash that could be used to buy stocks, analysts said, and traders abandoning bearish wagers could also support the rally. Many investors were skeptical for much of the nearly 11-year bull run that ended earlier this year, yet major indexes continued marching to records.

Gauges of sentiment show investors slowly growing less fearful. The percentage of investors in an American Association of Individual Investors survey who said they are bearish on stocks over the next six months fell in five consecutive weeks to 38% in the week ended Thursday from 53% in early May. Meanwhile, fund managers surveyed by Bank of America last month increased their investments in global stocks, though their positions still remained well below long-term averages.

Some market watchers say the "**FOMO** trade," referring to investors' **fear** of **missing out** on gains, has added fuel to the advance. Battered corners of the market such as energy stocks and shares of smaller companies have soared this quarter, signaling to analysts a rotation toward unloved investments and a shift among trend-following funds that are latching on to the momentum.

"It's the FOMO trade that has been deeply instilled in markets by central banks' repeated willingness to intervene" Mohamed El-Erian, chief economic adviser to German insurer Allianz SE, said in an email.

That optimism signals to some analysts that markets have risen too quickly, leaving them ripe for a pullback. Individual investors making bets through online brokerages also have contributed to the buoyancy in markets beyond stocks.

U.S. crude-oil futures have risen above **$35 a barrel after** briefly falling into **negative** territory **for** the **first time** ever in **late April**. Investors also have poured money into funds tracking corporate debt in recent weeks.

Behind these moves are **historic steps** by the **Fed**eral Reserve **and E**uropean **C**entral **B**ank to **prop up** the **world economy**. Yet even for those who anticipated that the Fed's lending programs would support stocks, the scope of the rebound has been a surprise.

"I didn't think that the reaction would be as strong as it is now," said Mark Spiegel, managing member and portfolio manager of New York hedge fund Stanphyl Capital Partners. Mr. Spiegel holds a long position in a group of small value stocks that appear cheap relative to their earnings, but he is also wagering against the Invesco QQQ Trust, a popular tech exchange- traded fund.

Additionally, he holds a long position in the SPDR Gold Trust, an ETF designed to track the haven metal. A doubter of electric-auto maker Tesla Inc., Mr. Spiegel said he has pared back his bet against the stock to comprise only a small part of the fund.

Although many analysts expect large technology companies to continue growing, earnings projections for most other sectors are bleak. Figures from Credit Suisse show it takes 2½ years on average for S& P 500 earnings to return to prerecession highs after economic downturns, and some investors also project a slow rebound in spending by consumers.

"Even in the best scenario, we think the economy is going to take two to two-and-a-half years to get back to pre-Covid activity levels," said Tony Roth, chief investment officer at Wilmington Trust Investment Advisors. The firm moved in February to holding a smaller position in stocks than the benchmark it tracks from a larger position.

Another firm that is skeptical about the surge in cyclical investments tied to the economy: New York Life Investments.

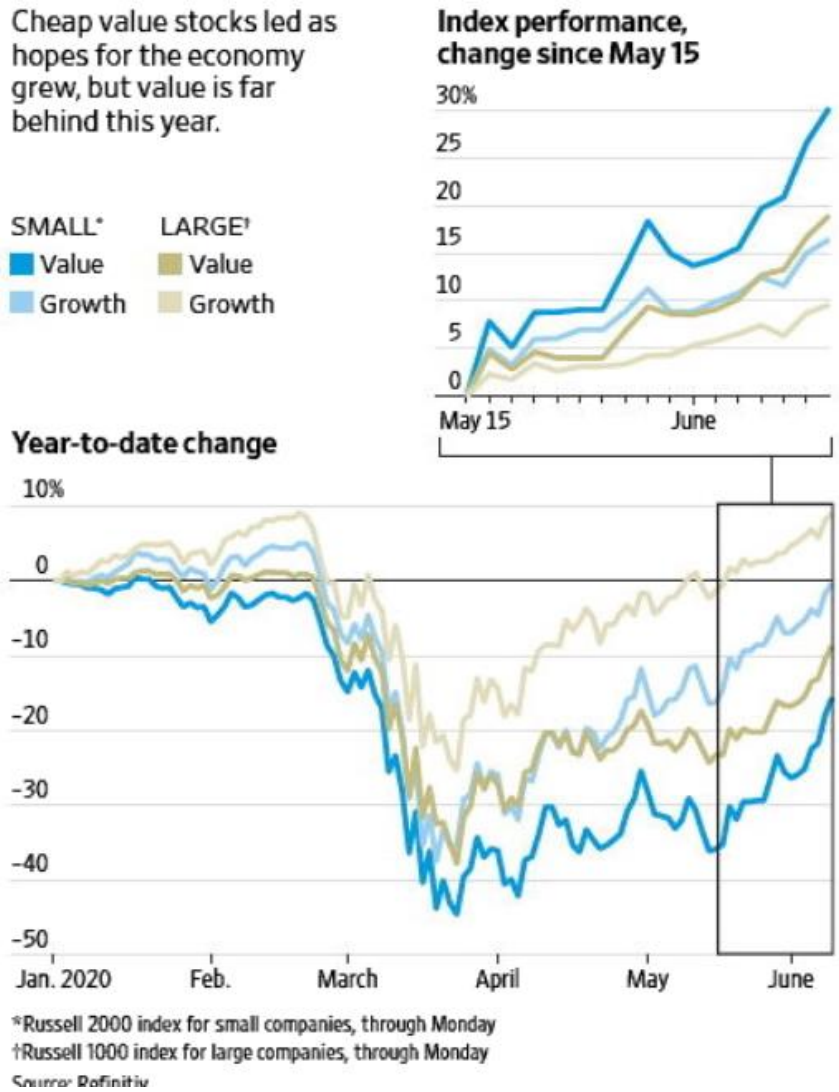
The company is maintaining a smaller position in small-cap stocks than its benchmark, believing the gains will eventually fizzle as the economic recovery unfolds, said Lauren Goodwin, a multi-asset portfolio strategist and economist at the firm.

In explaining the market's rise, she cites a stampede toward small-caps and other cyclical assets by traders that follow momentum.

"Nobody was positioned in that direction," she said. "We feel comfortable at this point missing out on the last bit of upside to protect against risks."

Risk Theory Bullish on Value

by James Mackintosh – WSJ Streetwise Column– Jun. 10, 2020



This is the hope of investors in **cheap**, or "**value**," **stocks**: One day, eventually, they won't be so cheap. For many decades, over long periods, this generally worked, and value investors made money.

There used to be a fierce debate about exactly why. Value stocks have been having a great few weeks, after a truly miserable time during lockdown. So it is time to exhume this ancient argument.

Prof. Eugene Fama, who won an economics Nobel Prize, argued that value stocks outperformed because they were riskier, and the efficient stock market rewards higher risk in the long run. A different view holds that investor behavior is the answer: Investors shun bad companies more than they should, leaving them artificially cheap. Those with the gumption to buy will be rewarded.

These days, the behavioral finance view triumphs, thanks in part to the damage done to efficient-market theories by the 2000 dot-com bubble and the 2007 housing blowup.

But what is happening now? Did investors artificially pummel airlines and the like during the lockdown? Or is the market reacting to the improved economic outlook and efficiently repricing stocks?

The answer matters because on the behavioral view, value stocks can continue to do well even without further good news on the economy. Merely narrowing the vast gap between the valuation of cheap and expensive stocks would give value investors a decent return. On the efficient markets view, the outlook depends on what happens to

the economy. If things continue to improve, the risks for value stocks will continue to drop, allowing them to outperform.

Iwant to set out the case for the value rally being a product of efficiency, driven by changes to the economic outlook.

Value stocks started outperforming in mid-May. Economically sensitive banks, industrial and energy stocks rose by more than everything else, while the dollar began to decline as there was less need for its safe-haven properties. Lagging behind the S& P 500 were health care, consumer staples, technology and communication services, all the places investors hid during lockdown. Bond yields joined in this month, rising sharply, and value stocks soared.

This was a classic cyclical rally.

Value is currently far more exposed to economic growth, with many more financial stocks and fewer technology stocks classed as value than in the wider market. Growth—the opposite of value—is dominated by tech. It is just chance that the value-growth split has so much overlap with stocks that do well or badly from opening up the economy. The current group of value stocks became cheap over a decade of weak economic growth and demonstrable success from tech giants. Had the coronavirus hit at another time, it might have hit the then-expensive stocks rather than the cheap ones.

The efficiency theory holds that value stocks must be riskier to justify higher returns. There is ample evidence of that risk-reward combination now. Consider the airlines, where a return to lockdown might force some out of business. Airline stocks have become a bet on survival—the riskiest of all bets. That helps explain why the better economic news led to big price rises at American Airlines, United Airlines and Delta Air Lines last week. If the choice is between survival and a stock price of zero in bankruptcy, better odds of survival justify huge price jumps.

None of this is proof, of course. The market can be both efficient when considering the direction a stock should move and wildly wrong when assessing how far it should go. Value investors can agree that shutting down the economy is bad for their portfolio, but also argue that panicky investors have been pricing in too high a chance of armageddon.

The gap in short-term performance between value and growth stocks has certainly been extreme. On the Russell 1000 Value index's definitions, value lagged 17 percentage points behind growth over its worst three-month period (to late May). Even in the dot-com bubble, value was only a little further behind.

The comparison to the awful economies of 1932 and 2009 works better than the behavioral mistakes of the dot-com bubble. Both 1932 and 2009 set up for a value rebound, because the government stepped in to save the economy; but neither value rally lasted. I hope all works out well for both the economy and value, but it would be dumb to ignore the risks to both.

S&P Beat Actively Run Funds in Tumult

by Karen Langley – WSJ – Jun. 11, 2020

Most U.S. large-cap stock-picking funds underperformed the **benchmark S&P 500** during the tumultuous **early months** of **2020**, according to new data from S&P Dow Jones Indices.

As fears of the coronavirus pandemic and related economic damage rippled through the markets, the **S&P 500 tumbled 34% from** its **February high to** its **March low**. But by the **end of April**, the index had shot **back up 30%** and posted its **best one-month percentage gain since January 1987**.

It was a **prime environment** for **active management** – giving **stock pickers** an opportunity to take profits from shares that bounced too high or add to positions in companies that sold off too much.

But during those volatile months, the majority of U.S. equity funds put up a **weaker performance**, **after fees**, **than** a **broad stock index**, according to S& P Dow Jones Indices.

"2020 has been a **ripe environment for active management to shine** and show the value that stock selection can provide," said Todd Rosenbluth, senior director of exchange-traded fund and mutual-fund research at CFRA.

Active managers, he said, "got a pitch down the middle, and they're swinging and missing more often than they would like."

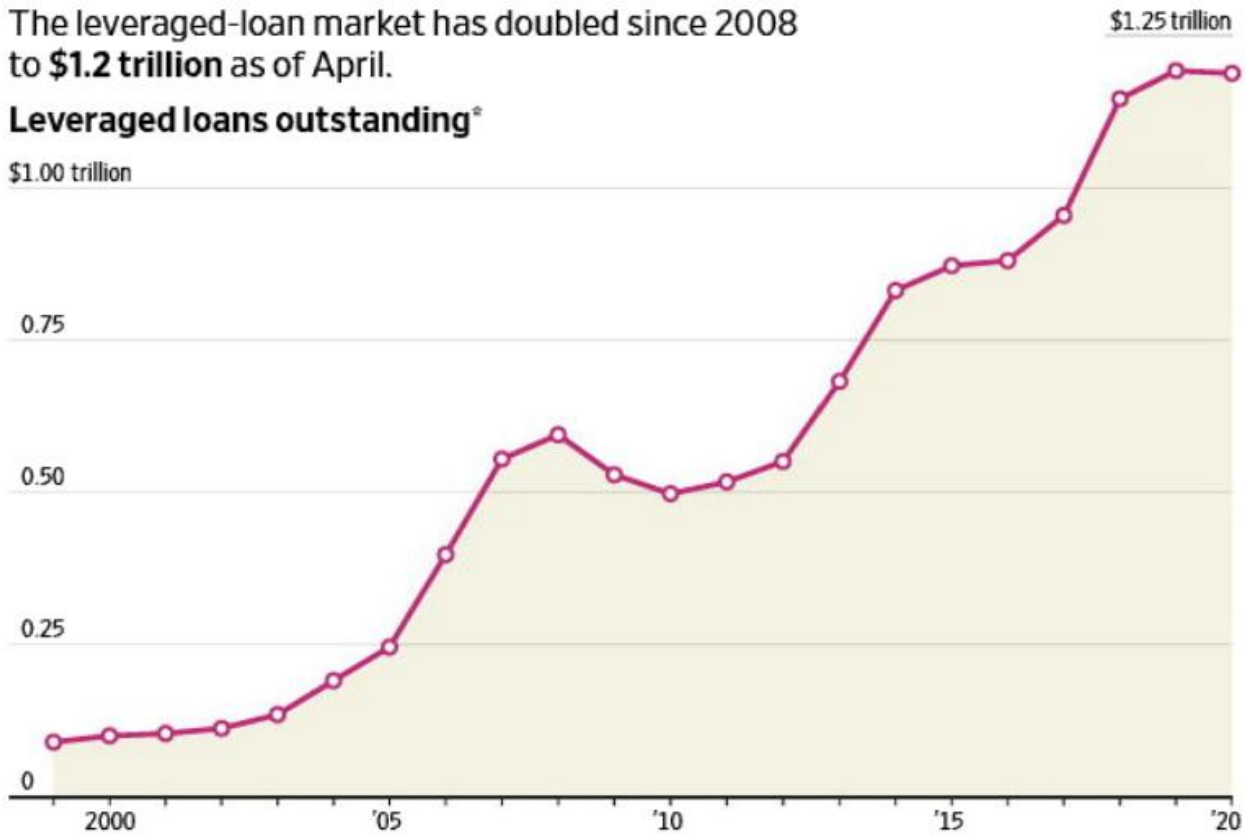
Of all **actively managed U.S. stock funds**, **64% underperformed** the **S&P Composite 1500 index,** which tracks large-, mid- and small-cap stocks, from **January through April**.

S&P Fired Staffer After He Briefed Senate

by Cezary Podkul – WSJ – May 22, 2020

In **November**, an **S&P Global, Inc. employee briefed Senate Banking Committee staff** members on the **growing risks** in the **$1.2 trillion market** for **loans** that **finance private-equity buyouts**.

In a meeting with Democratic Senate staff, **Andrew Park** of S&P **laid out how** the **speculative debt would face** a **torrent** of **credit-rating downgrades once** the **economy turned**. That **would hurt investors who bought bonds secured by the loans**, **many** of which are **rated by S&P**.



A few weeks after the meeting, one of **S&P**'s Washington lobbyists called Mr. Park and demanded to know why he attended the meeting and what was discussed, according to Mr. Park. On Jan. 6, the firm **fired Mr. Park** for **failing** to **clear** his **presentation with compliance staff**. That was a violation of a company policy requiring such clearance, S&P said in a response to a wrongful- termination complaint filed by Mr. Park.

The **coronavirus pandemic made Mr. Park's warnings look prescient**. **Downgrades** o**f loans owed by heavily indebted corporations** have **spiked sharply since February**, **eclipsing levels** seen **during** the **financial crisis**, according to S&P. More than **1,600 bonds** tied to loans owed by risky borrowers have been put **on watch for downgrades** by S&P, Moody's Corp. and Fitch Ratings. While deteriorating

economic conditions have hit businesses hard, the wave of downgrades **calls into question** the **accuracy of** at least **some** of the **original ratings**.

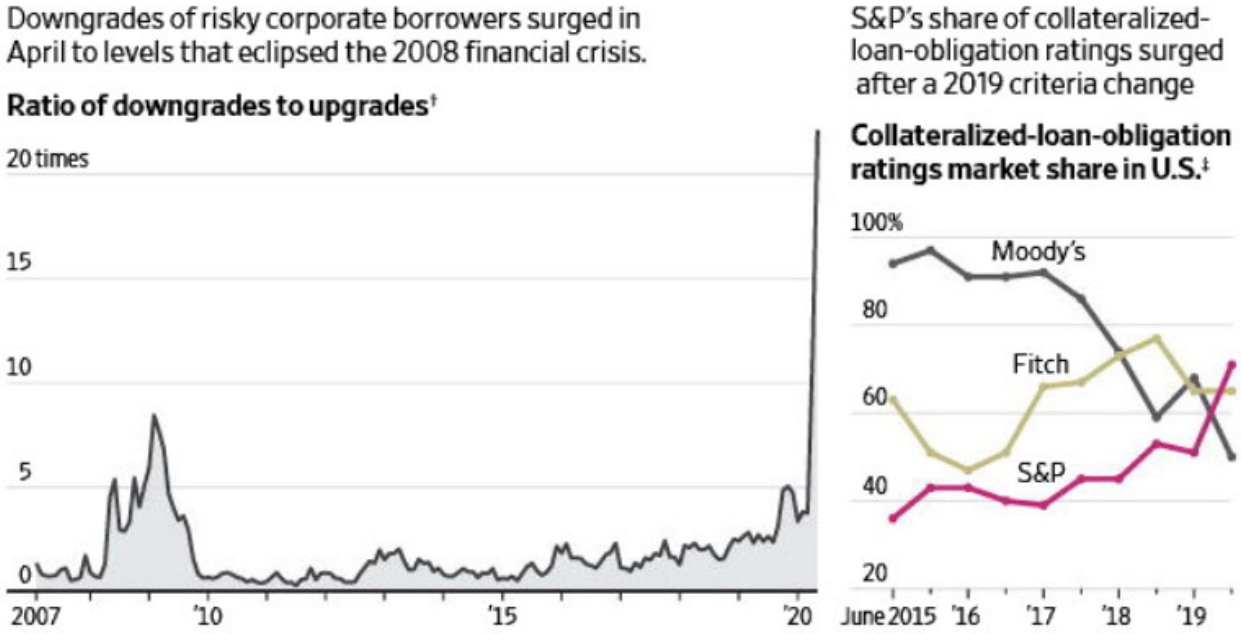


*Chart tracks leveraged loans outstanding in the S&P/LSTA Leveraged Loan Index. Figure for 2020 is as of April, all other years are year end.
†Chart shows rolling three-month ratio of downgrades to upgrades for companies in the S&P/LSTA Leveraged Loan Index.
‡Market share is based on the value of rated deals. More than one firm can get hired on a deal, so shares can equal to more than 100%.
Sources: LCD, a unit of S&P Global Market Intelligence (ratio, leveraged loans); Asset-Backed Alert (market share)

Mr. Park filed his wrongful-termination complaint against S& P under the federal government's whistleblower laws, saying he was retaliated against for giving information to the Senate staffers. He now works for Americans for Financial Reform, the organization that arranged the November briefing and which lobbies for tighter financial regulation, including of credit-rating firms.

Mr. Park, 33 years old, told the Democratic Senate staffers that one source of risk was **companies gaming** the **system by hiring** the **ratings firms that** tend to **give their bonds** the **highest grades**. Mr. Park didn't work for S&P's bond-rating unit, but in his work as a senior editor at an S&P-owned news service that covered corporate lending, he frequently saw signs of this taboo behavior, which both issuers and ratings firms acknowledge happens but which they don't like discussing.

"Word got out about how I was speaking about **rating shopping**, and I was fired," Mr. Park said in an interview.

S& P said in a statement that it did nothing wrong in firing Mr. Park and that it will "vigorously defend against all claims" in his complaint, which was filed with the Occupational Safety and Health Administration.

Regulators have been sounding alarms about the market for the risky corporate debt, known as **leveraged loans**. Last May, **Fed**eral Reserve **Chair**man Jerome **Powell said loosening lending standards** have **spurred growth** in **borrowing** that was **outpacing companies' ability to repay**.

The following month, **S&P relaxed** the **ratings criteria** it uses to **evaluate collateralized loan obligations**, or **CLOs** – a type of **bond** whose **payments** are **tied** to **pools** of **leveraged loans**. The **new criteria reduced default expectations** for **loans backing CLOs**. S&P said in a statement that additional data and the evolution of the CLO market justified the move.

CLO issuers are the **biggest buyers** of **leveraged loans,** making them an important intermediary between private-equity firms looking to finance takeovers and investors willing to bankroll them. Ratings firms stand in the middle, and their grades are a crucial input into the profit calculations of CLO issuers, who pay for the ratings.

S&P's market share in U.S. CLOs rose from 51% in the first half of **2019** to **71% after** the **methodology change**, vaulting over Fitch and Moody's for the first time in five years, according to industry tracker Asset-Backed Alert. CLO deals usually get rated by two firms.

The ratings enable bankers to slice the pools of loans, which are typically rated junk, into bonds with various levels of risk. The riskier, lower-rated slices are first in line to suffer losses and can earn higher returns than the safer pieces. The safest pieces are rated triple-A.

But **investors rarely get** a **complete picture** of the **risks** because issuers selectively disclose the best ratings on each bond, leaving CLOs with patchworks of missing grades. Ratings firms enable the **selective disclosure** by allowing issuers to decide which of their grades get published. In the past, some ratings firms insisted on making that decision themselves.

Mr, **Park** had **studied finance** in **college** and **worked** as an **analyst** for **P**acific **I**nvestment **M**anagement **Co**., the bond-fund manager. In **2015**, he **joined S& P**, where his main task was to summarize details of CLO deals. When he wrote up Bain's 2019 deal, a reader inquired to ask if the ratings were a typo, Mr. Park recalled.

In late October, after he took a few days off to get married, Mr. Park got an email from Marcus Stanley, policy director for Americans for Financial Reform, inviting him to speak about CLOs to some staffers for Sen. Sherrod Brown (D., Ohio), the ranking member on the Senate Banking Committee.

Mr. Park had met Mr. Stanley at a Washington event a few weeks earlier and was familiar with his organization. Mr. Park realized that it wasn't normally a reporter's job to give such presentations, but he figured that it would be a good opportunity to develop sources, so he agreed.

"You're going to be thankful you met me," Mr. Stanley told Mr. Park as they entered a Senate office building for the meeting, according to Mr. Park.

Mr. Park created a 20-slide PowerPoint presentation, which he brought to the meeting. In it he explained that while CLOs held up during the 2008 financial crisis, there were signs that they wouldn't do the same the next time the economy crumbled.

Rating shopping wasn't a part of Mr. Park's presentation, but the topic came up during the discussion, according to Messrs. Park and Stanley and another guest at the

meeting. Mr. Park said he was asked a question about rating shopping and answered it honestly based on his experience.

After his firing, Mr. Park joined Americans for Financial Reform to work for Mr. Stanley. Mr. Stanley said he hired Mr. Park because of his detailed understanding of financial markets. “That’s why I sought him out,” he said.

On Dec. 3, Sen. Brown sent a letter to banking regulators asking for more oversight of leveraged loans and CLOs. He wrote that “in yet another echo of the 2008 crisis, market participants have reported concerns of **ratings shopping**.” The letter footnoted an S&P presentation to his staff, though it didn’t directly attribute the information to Mr. Park.

By early December, credit ratings were getting attention in Washington. Lawmakers began asking the Securities and Exchange Commission about boosting oversight, and one of the agency’s advisory committees had started examining alternative ratings business models that would lessen the **industry’s conflict of interest**.

Safe Utilities Have Been More Volatile Than Broader Stock Market

By Anna Hirtenstein – WSJ – June 14, 2020 7:00 am ET

Shares of utilities have been fluctuating more than the S&P 500 as investors fret about impact of coronavirus

Utilities' stocks have long been seen as a safe place to park cash and collect steady dividends. But as the coronavirus spread around the world this year, they have been more volatile than the broader market.

In March and April, **shares of companies that sell electricity, water and gas posted bigger daily moves than the S&P 500 on a majority of days. The only other time this has happened in the past two years is during a bout of market volatility in February 2018**. So far in June, it is a tie, with utilities moving more on five days.

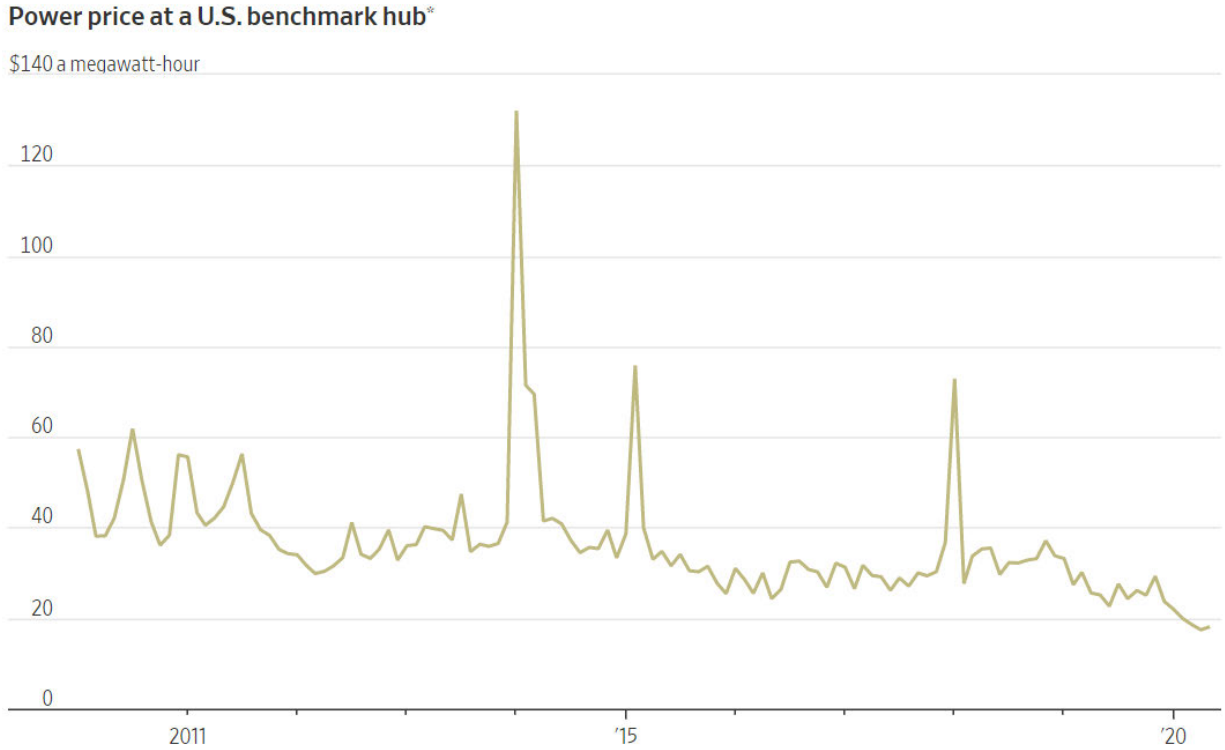
The utilities sector within the S&P 500 is down almost 10% this year, even as the benchmark index rebounded to erase most of its losses.

That is because of concerns about falling power demand and the spike in unemployment following the lockdowns put in place to curb the outbreak, analysts said. Millions of people have lost their jobs in recent months, prompting concerns that they may stop paying their bills. As dozens of companies cut or suspended their

dividends to preserve their cash piles, some investors wondered if the major utilities could be next.

"Utility investors are not used to uncertainty,'' said Jeremy Tonet, an equity research analyst at JPMorgan Chase & Co. "There were a lot of concerns with regard to Covid-19 and how much it could impact the space."

Utility stocks are normally popular with pension funds and insurers, who buy them for their stability and reliable dividend yields. Those expectations came into question during the peak of the market turmoil that ensued in March.



*Monthly average price at PJM West Hub ATC (Pennsylvania, Jersey, Maryland Power Pool), the most liquidly-traded U.S. power hub
Source: Bloomberg New Energy Finance

The lockdowns have resulted in a significant drop in energy use as commercial and industrial activity ground to a halt. A benchmark for wholesale power prices in the U.S. fell 20% in April, compared with the beginning of the year, and is still down nearly 15%, according to data from Bloomberg New Energy Finance. The Energy Information Administration said on June 9 that it expects electricity consumption in the U.S. to decline 5.7% in 2020.

Despite this, nearly all major U.S. utilities have reaffirmed their full-year guidance, according to JPMorgan. **One of the few exceptions** is **Consolidated Edison Inc. which operates primarily in New York, the U.S. city that has been hardest-hit by the coronavirus.** Con Ed last month cut its 2020 earnings guidance.

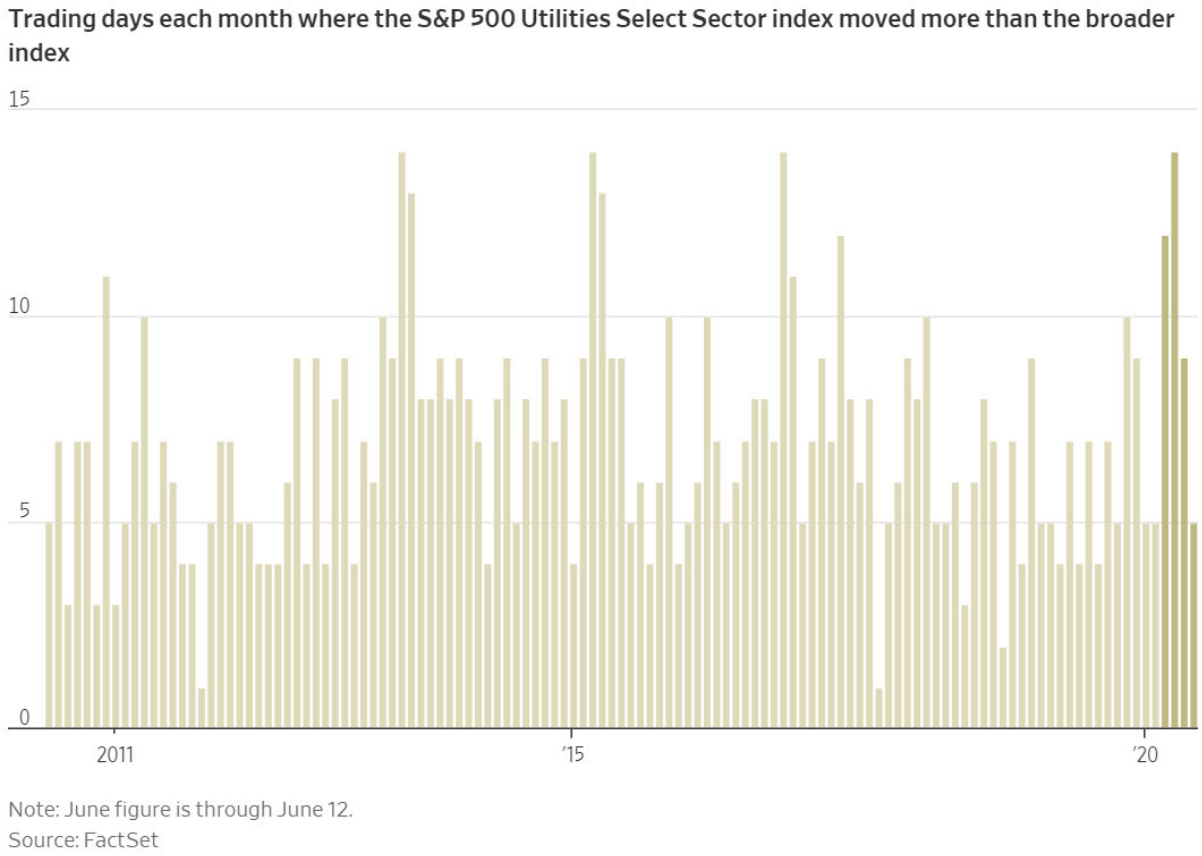
Meanwhile, CenterPoint Energy Inc. CNP +0.78% in Texas has been one of the few utilities to trim its quarterly dividend so far.

The regulated nature of the industry means that the revenue holds steady even if power prices fluctuate or sales fall, according to Noah Barrett, head of energy and utilities research at Janus Henderson. There are rules in place in many states that decouple energy demand from the companies' cash flows and fix a rate of return on their investments to ensure that the businesses supplying the population with essential services remain in good health, he said.

"The dynamic we saw this year with Covid-19 is something that no one knew how to model," given the uncertainty around electricity or natural-gas demand, Mr. Barrett said. "If you look at the stability of the earnings, it hasn't really changed."

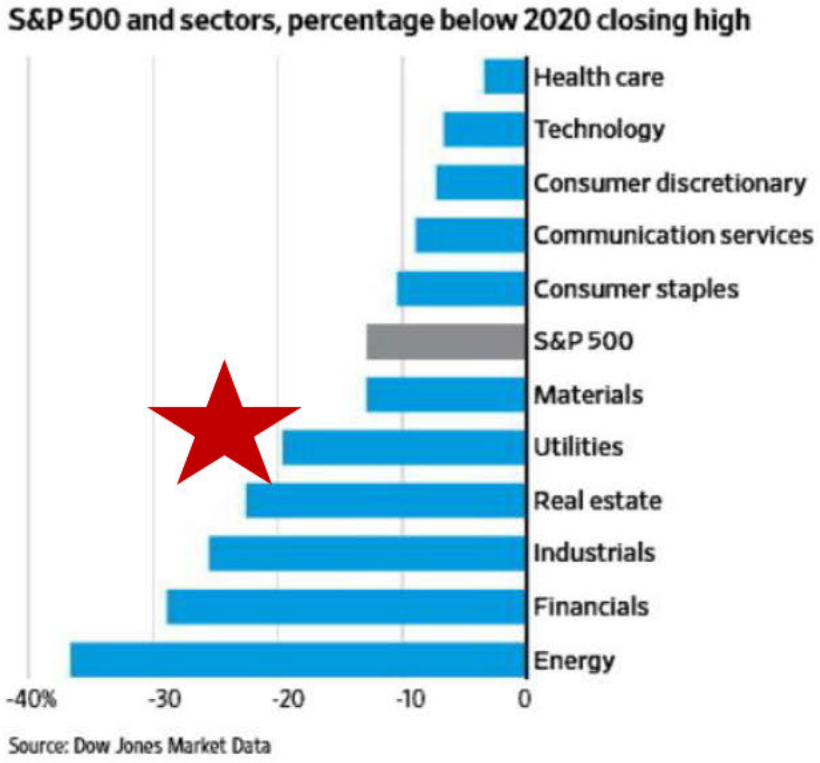
The utility companies' very stability may now be working against them, he said. Some investors are seeking out stocks that have been hard-hit amid the economic downturn and could rebound sharply, or sectors such as technology that could benefit during lockdowns.

Another reason that utilities' stocks are currently unloved is because of the sharp moves seen in March, said JPMorgan's Mr. Tonet. Passively managed funds and asset



managers that use algorithmic or quantitative strategies may not continue to view these stocks as predictable, low-volatility investments.

But in the long run, the companies still have strong fundamentals and "there's room for utilities to regain their stance as a defensive stock," he said.



Sitting on Bond Profits? Sell, Switch or Wait?

by Dan Weil – WSJ – Jul. 6, 2020

Profits are a good thing, but that **doesn't** mean it **always makes sense to take** them.

If you've held bonds or bond funds over the past six, 12 or 18 months, you're looking at a sizable capital gain. For example, Vanguard Total Bond Market ETF (BND) rose 7% in the one-year period through June 30, a hefty move for a bond fund.

So if you're one of the lucky ones, what do you do with your bond profits? In general, it's best not to sell in order to collect them, though there are exceptions, financial advisers say.

The main issue is that if you book your capital gain, you will most likely have to take more risk to match the income you are now receiving from your bonds and bond funds. That's because the **lower interest rates** that **have meant higher prices for your bonds also mean lower yields for** the **bonds you might buy with** the **proceeds of** your **capital gain**.

To replicate the **income** you're **receiving from** your **current bonds**, you **would have to opt for bonds with longer maturities** and/or a **weaker credit profile**.

"There's **no** such thing as a **free lunch** in this," says Dan Goldie, a financial adviser for Buckingham Strategic Wealth in Palo Alto, Calif. "It's merely the market pricing mechanism working properly."

Advisers note that the **purpose** of your **bond portfolio** should be to **provide stability** and **diversification** to **offset** the **risk of** your **stockholdings**, **along with** an **income stream**. "I **don't** think you should **try for high returns with fixed income**," Mr. Goldie says. "Try for that with equities."

In addition, if you're selling bonds or bond funds in a taxable account, you'll have to pay a **capital-gains tax**. For wealthy people in a high-tax state, that charge is over **30%**. So you would have to replace your bonds with ones that have much higher yields or with some other high-return asset to make up for the tax hit.

"I don't like the arithmetic of that," says Chris Litchfield, a retired hedge-fund manager who is now a private investor in Greenwich, Conn.

When It Makes Sense:

In some cases, though, it might make sense to take gains, especially in a nontaxable retirement account. One example would be **moving to safer bonds**—ones with **shorter maturities** and/or **less credit risk**, advisers say. "If you have concerns about safety issues, this is an opportunity to de-risk – perhaps from high-yield [junk bonds] to Treasurys," says Andy Schuler, head of PNC Wealth Management's investment program.

Some investors might want to move in the opposite direction, taking more risk to pick up some additional yield. If all your bond assets already are in safe bonds, which now have negligible yields, you might contemplate taking profits on some of your holdings and putting them into riskier bonds, some advisers say.

Say you own intermediate- or long-term Treasurys. "If you're looking to take a little off the table, you can rebalance into investment-grade corporate bonds or municipal bonds if you're in a high tax bracket," says Collin Martin, a fixed-in- come strategist at Charles Schwab. Municipal bonds are tax-free.

If you're a risk taker, you might even consider dabbling in high-yield bonds, some advisers say. Mr. Litchfield says it's wise to have a **diversified bond portfolio**, including Treasurys, municipal bonds, and both high-quality and high-yield corporate bonds . **Government bailouts**, particularly from the Federal Reserve, have **made high-yield bonds less risky**, he says.

What about taking your bond profits and venturing into stocks, particularly dividend stocks, which in many cases would provide more income than your bonds?

Advisers recommend against it, unless you're underweight equities in your asset allocation, which is unlikely given the stock market's recent run-up. Again, remember that your **bond-holdings** are **meant** to **provide ballast for** your **portfolio**, including an **income stream**, **rather than large returns**.

While dividend stocks offer regular income, for the **most part** they are **still riskier than high-quality bonds**. "Dividend stocks can be a good way to invest broadly in the stock market, but we don't like to talk about them in the context of bond investing," says Mr. Martin.

One investment Schwab favors crosses the border between stocks and bonds: preferred securities. They have characteristics of both asset classes.

Don't Count on Higher Rates:

Perhaps you've thought of selling your profitable bonds and leaving the money in cash, hoping that interest rates will rise and you can then reinvest the money in bonds with higher yields. Not a good idea, advisers say.

"We never think hope is good," Mr. Martin says. "The **Fed** has **indicated short-term rates** will likely be **near zero for 2½ years or more**."

Six Months That Shook the World – WSJ – Jun. 27, 2020

A **global pandemic, widespread unemployment, nationwide protests** and a roller-coaster stock market have created the **most tumultuous period in recent memory.**

140,000 Businesses listed on Yelp closed after March 1 and **remained closed** as of June 15.

48% Increase in **U.S. filings** for **chapter 11 corporate bankruptcy protection last month**, compared with May 2019.

72% Drop in the number of **rigs drilling for oil in** the **U.S**. this year.

81% Decline in **travelers** going **through TSA checkpoints** Wednesday, compared with the same date last year.

30% Percentage increase Google says it hopes to achieve by 2025 in leadership positions for 'underrepresented groups' at the company. Currently, 2.6% of Google's leadership is black.

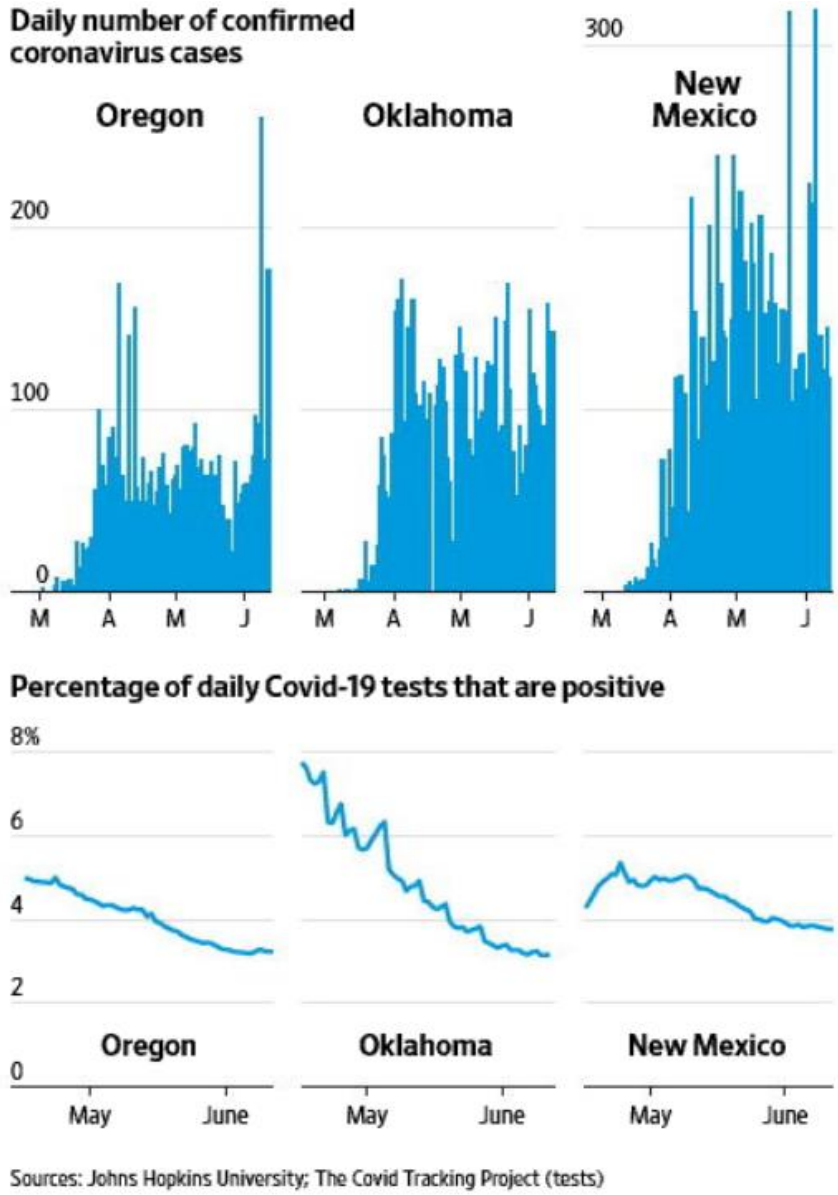
3.2% Percentage of senior executive positions held by black people in U.S. business.

19.1 million Decline in payroll jobs in May 2020 compared with December 2019.

Some Reopening Plans Put on Pause

by Talal Ansari – WSJ – Jun. 13, 2020

As confirmed coronavirus cases in the U.S. surpassed two million this week, driven in part by surges in more than a dozen states, some places were citing the increases as reasons to pause on reopening plans.



Oregon Gov. Kate Brown is delaying the state's reopening by a week because of a "significant increase" in Covid-19 infections. "Think of it as a statewide 'yellow light,' " Ms. Brown said.

As of Thursday, Oregon had 5,237 cases, up from 4,474 a week earlier. While the total number of cases has increased, the percentage of positive tests in Oregon for Covid-19, the disease caused by the coronavirus, has hovered around 3% since the beginning of June. During that time, the state has been performing an average of 2,800 tests a day.

"This one-week pause will give public-health experts time to assess what factors are driving the spread of the virus," Ms. Brown said.

Nashville's Mayor John Cooper made a similar announcement Thursday after "slightly elevated" confirmed coronavirus numbers were recorded.

Some states that largely avoided the case levels and deaths that marked the pandemic's early days in some places are now seeing record hospitalizations. Experts fear that loosened restrictions, the desire to restart the economy and summer's approach led many Americans to begin letting down their guard.

Increased testing is one factor behind the additional cases, but the growth is causing alarm among officials, who are worried about broader spread of the disease.

The U.S. recorded its first million cases over roughly three months, from late January to late April. Just over six weeks later, that figure has grown to more than two million, according to a Wall Street Journal analysis of data from Johns Hopkins University.

Nationwide, reported cases have increased by an average of 21,500 a day over the past two weeks. On June 5, the U.S. had 1.87 million confirmed cases and more than 108,000 deaths from Covid-19, according to data from Johns Hopkins. This week, there are 2.02 million confirmed cases and more than 113,000 deaths.

“The U.S. has failed to emulate the success of other high-income countries that have brought transmission well under control through testing, contact-tracing, and clear public health messaging about the need for social distancing,” said Joseph Lewnard, assistant professor of epidemiology at the School of Public Health at the University of California, Berkeley.

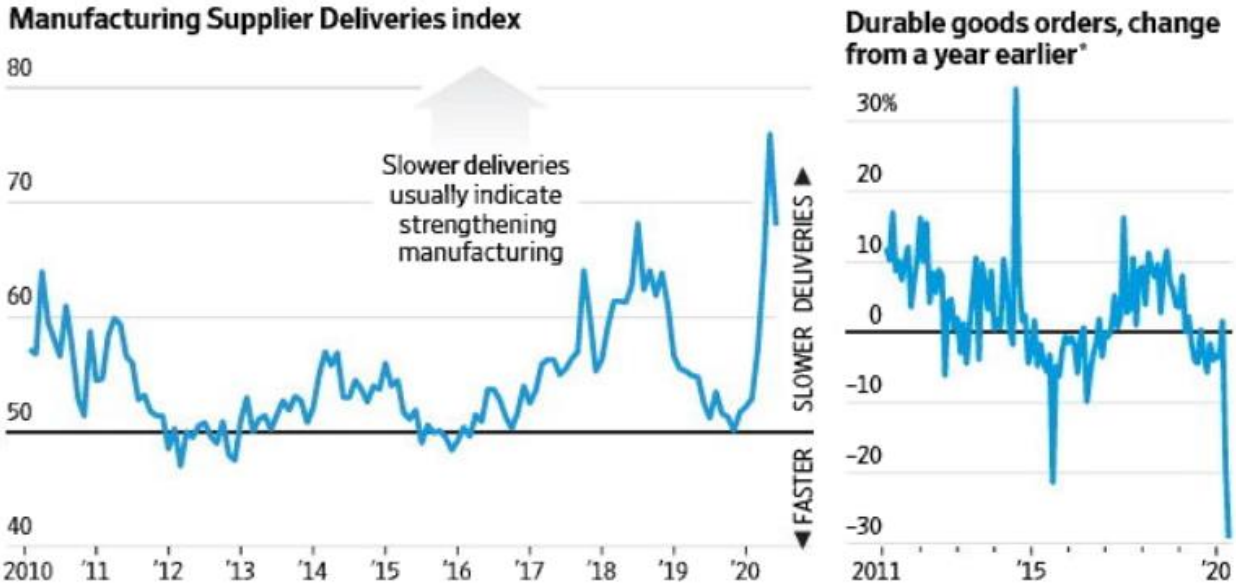
In Oklahoma’s Tulsa County, where President Trump is set to have a rally next week, daily confirmed cases hit a record high on three different days this week, according to data from the Tulsa Health Department.

The Centers for Disease Control and Prevention issued its latest ensemble forecast, which now suggests there likely will be between 124,000 and 140,000 total reported Covid-19 deaths by July Fourth. The death toll in the U.S. crossed 100,000 two weeks ago.

Supply Snafus, New Costs Hobble Factories

by Bob Tita and Austen Hufford – WSJ – Jun. 5, 2020

The pandemic has disrupted production and lengthened delivery times, pushing up a supplier-deliveries index that typically indicates stengthening manufacturing. Durable goods orders also fell to their lowest level in years.



*Seasonally adjusted
Sources: Institute for Supply Management (supplier index); U.S. Census Bureau (durable goods)

Manufacturers emerging from weeks in hibernation during the coronavirus pandemic are accelerating production with **jumbled supply chains** and **less efficient plants**, making it **harder to rebuild** the **weakened U.S. industrial sector**.

Some U.S. factories are looking for alternative suppliers to compensate for plants that remain closed or are overwhelmed by orders for items in high demand. Other companies say **new protective equipment and procedures** to add space between workers will **weigh on** their **profits and productivity**.

Meanwhile, many manufacturers are encountering bleak conditions in **industrial markets** that have **shrunken with** the **contracting U.S. economy**. **Durable-goods orders** in the **U.S.** are at the **lowest level in** a **decade**, and surveys of purchasing managers at manufacturers in the U.S., Europe and Asia suggest any recovery in the months ahead could be tentative.

Other companies say they haven't been able take advantage of markets where demand has been more resilient. Ardisam Inc., which makes fishing and gardening equipment that is in high demand from people spending more time outdoors, **hasn't been able to get enough parts** for fence-post diggers and chicken pluckers **from factories in China**.

Chief Executive Michael Furseth said Ardisam's sales would have been 25% higher this spring if the Wisconsin-based company had stock on hand to fill all the orders it received. "You are just behind, and you can't catch up," he said.

Wanxiang America Corp., an Illinois-based unit of one of China's largest auto-parts makers, restarted more than 20 plants in the U.S. last month after undergoing some modifications to reduce contact between employees.

Pin Ni, president of Wanxiang America, said the idling of auto production in the U.S. bought time for Wanxiang's own supply chain in China to recover from lockdowns imposed on factories there earlier this year. But he said he expects some suppliers to go out of business this year because they won't be viable at lower production rates anticipated across the auto industry.

"**Any one failure** is going to **impact everybody**," Mr. Pin said. "We're **all co-dependent on each other**."

General Motors Co. last month **delayed plans** to **increase production** of **pickup trucks** because of a **shortage** of **parts from Mexico**. Many manufacturing plants in Mexico, which surpassed China as the top trading partner to the U.S. last year, were ordered closed early during the pandemic. A gradual reopening of plants started Monday based on the level of contagion recorded in each of the country's 32 states.

China has largely reopened its industrial economy, but many U.S. buyers are only now using items that would have been made and shipped from there earlier this year, when the economy was locked down and cargo traffic had collapsed.

For other U.S. companies, strained overseas supply chains have created opportunities to fill orders domestically.

Left: Littlestown Foundry, Inc., a Pennsylvania-based producer of aluminum-cast components for electrical equipment, said it obtained about $350,000 of orders in the past year from a customer that wanted to shift about $3.5 million worth of work annually to the U.S. from China.

"The good work we gobbled up right away," said Glen Morrell, Littlestown's vice president.

Litttlestown last week resumed shipments of aluminum parts to Mexico, where a plant in Juarez that finished the parts had been idled by government coronavirus restrictions. As production accelerates, Littlestown is stockpiling more aluminum ingots than usual because deliveries have been less reliable.

"I **used to play inventories a lot closer than** I am right **now**," he said.

Other companies have become more cost-conscious as disrupted supply chains and new spending on safety protocols erode profits. O-I Glass Inc., the biggest domestic producer of glass bottles, said it is using more expensive raw materials to make glass because of a shortage of recycled glass. The volume of recycled glass from states with deposits on beverage bottles plunged by two-thirds in April after redemptions on empties were suspended as a safety precaution for retail workers.

"We've built our supply chains based on recycling," said Randy Burns, O-I's chief sustainability officer.

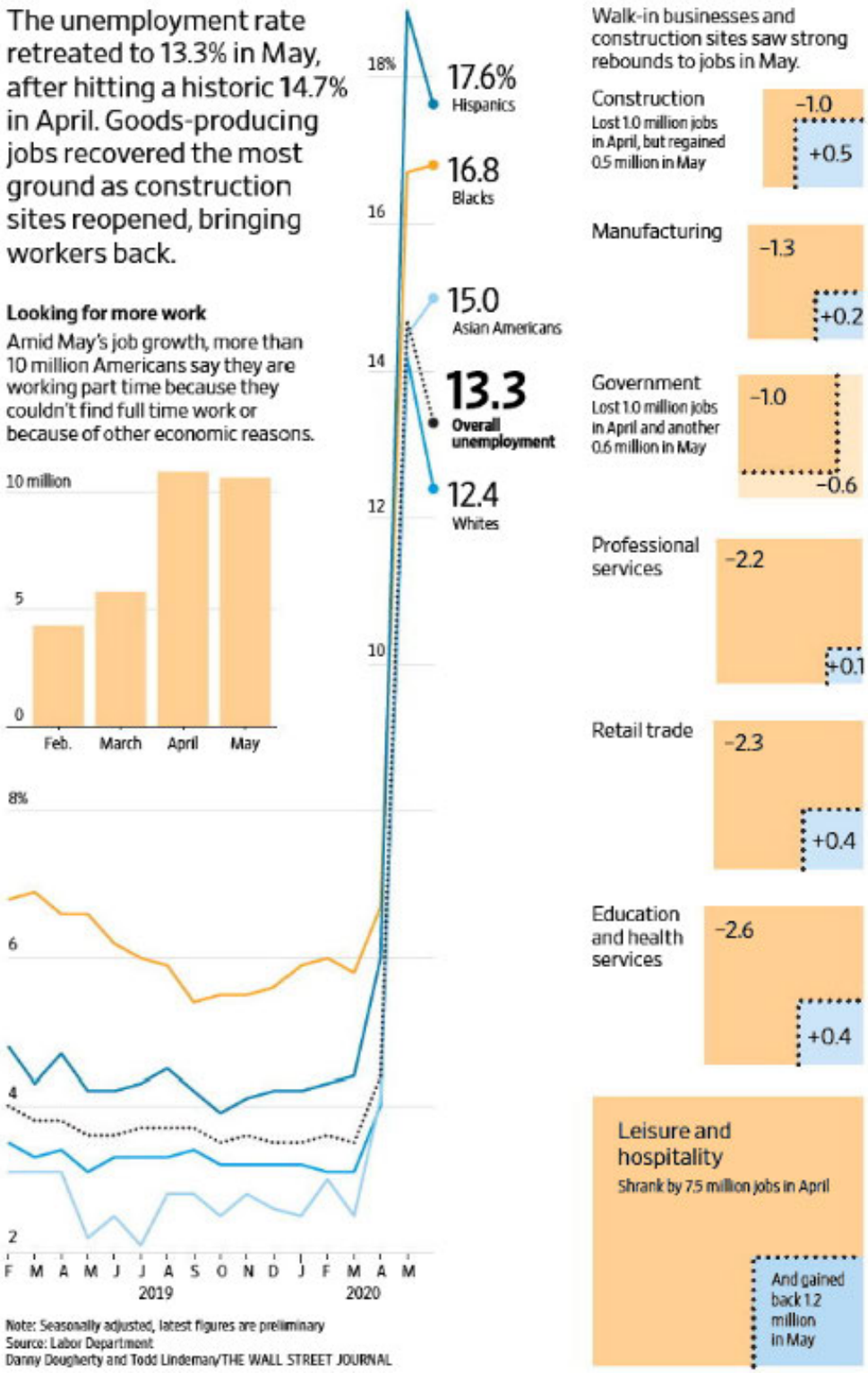
The virus has driven up costs and shaved profits for companies that haven't experienced supplier delays or falling sales. Housewares company Honey Can-Do International Inc. said its overhead costs have climbed, despite minimal disruption in shipments of kitchen, bathroom and home storage products from China, Vietnam and elsewhere in Asia.

Chief Executive Steve Greenspon said the company's Illinois distribution center is less efficient now because operations have been reconfigured to separate employees. For instance, the company is only allowing one worker at a time to unload shipping containers, rather than the two people that usually work together inside the cramped metal boxes.

"The container takes twice as long to unload," he said.

Surprise Job Gains Seed Hopes

by Josh Mitchell – WSJ – Jun. 6, 2020
Bob Tita contributed to this article

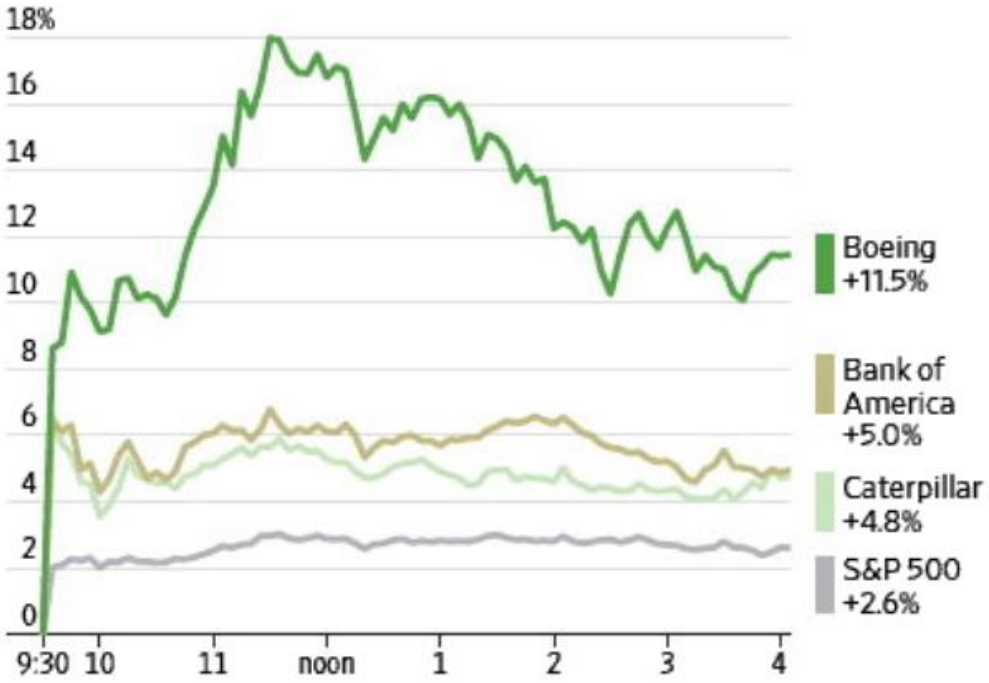


The U.S. labor market snapped back to life in May, restoring a chunk of the jobs it lost in the first two months of the coronavirus pandemic, although big obstacles lie ahead.

After two months of carnage, employers added 2.5 million jobs last month, the most in a single month on records dating from 1948. The jobless rate fell to 13.3% from April's 14.7%, a post-World War II high. The report defied predictions for more bad news.

Shares of cyclical companies, whose profits are closely tied to the economy's trajectory, helped lead the stock market's gains Friday.

Share-price and index performance



Source: FactSet

Despite last month's gains, the jobless rate is still historically high – nearly four times the rate in February. Employment remained down by nearly 20 million jobs, or 13%, since February, the month before the pandemic prompted states to shut down huge segments of their economies. By comparison, the U.S. shed about 9 million jobs between December 2007 and February 2010, a period that covered the recession caused by the financial crisis. Hurdles remain in the effort to get more people back to work, including the prospect of a second virus outbreak, pandemic-related safety regulations and social unrest from the May 25 killing of George Floyd.

But the jobs report boosted hopes that the economy has moved beyond the worst fallout from the pandemic and may recover more quickly than expected.

Stocks surged on the news, with the Dow Jones Industrial Average climbing more than 3%, the S& P 500 up nearly 3% and the Nasdaq heading toward a closing high.

"This is definitely in the right direction and suggests the U.S. economy may be faring better than some of those worst-case scenarios," said economist Lindsey M. Piegza of financial firm Stifel Nicolaus & Co. "But it remains to be seen if this is indicative of an ongoing positive trend or if this reflects the bare minimum of the labor force needed to reopen the economy."

Economists still expect a **slow and choppy recovery**. **Government aid** programs for households and businesses – which have pumped trillions of dollars into the economy – will **start to run out this summer and fall**. Many consumers and workers remain fearful of the virus and are staying at home. And protests and looting following the killing of Mr. Floyd, a black man who died in police custody in Minneapolis, led many businesses to board up and close.

Still, a significant number of Americans appear ready to come back to the marketplace, and businesses are eager to reopen to accommodate them. Restaurants and bars added 1.4 million workers last month – more than half the overall job gain – as new virus infections eased and many states began lifting shutdown orders. Other industries adding workers included construction, health care and retailers – among the industries that had been quickest to let workers go in March and April.

"The No. 1 customer call that comes in is not, 'Can I place an order?' It's, 'Do you have dining?'" said Matt Friedman, chief executive of Wing Zone, an Atlanta-based restaurant chain. In recent weeks the company added five to 10 workers to each of its two taverns in Georgia that recently reopened after being shut down since March.

Mr. Friedman cautioned, however, that the two restaurants are operating at far below capacity to comply with rules to prevent further spread of the virus, including increased space between tables. That will limit, for now, how fast he can rehire.

Sung Won Sohn, an economist at Loyola Marymount University, said the aid that Congress approved to help households is stoking demand. While 21 million workers remained unemployed last month, research suggests that **more than half** of **those laid off during** the **pandemic** are **earning more than** they **did at their jobs**, thanks in part to stimulus checks and extra $600 a week in unemployment pay approved by Congress.

"People have been cooped up in houses and apartments for weeks and they're anxious to get back," Mr. Sohn said. "They have money to spend – disposable income."

In May, a broader measure of unemployment – including jobless workers, those working part time and those who have given up the job search because they are too discouraged – stood at 21.2% in May. Many other workers have taken pay cuts.

Gregory Daco, chief U.S. economist at Oxford Economics, estimates that at least half of the workforce has lost a job, lost hours or took a pay cut.

The **jobless rate** for Latinos was 17.6% and for African-Americans 16.8%, far higher than for Asians at 15% and whites at 12.4%. Women were more likely to be unemployed than men.

Those permanently separated from their jobs totaled 3 million in May, a low level compared with prior downturns. In October 2009, when unemployment peaked after the financial crisis, there were 8.3 million such workers.

Manufacturers also are adding jobs. Tuff Shed Inc., a Denver- based manufacturer of backyard storage sheds, has called back the 500 employees it furloughed in late March, one-third of its total workforce. The privately held company is now trying to hire about 300 more employees for its 52 production sites as demand surges for its prefabricated wooden buildings.

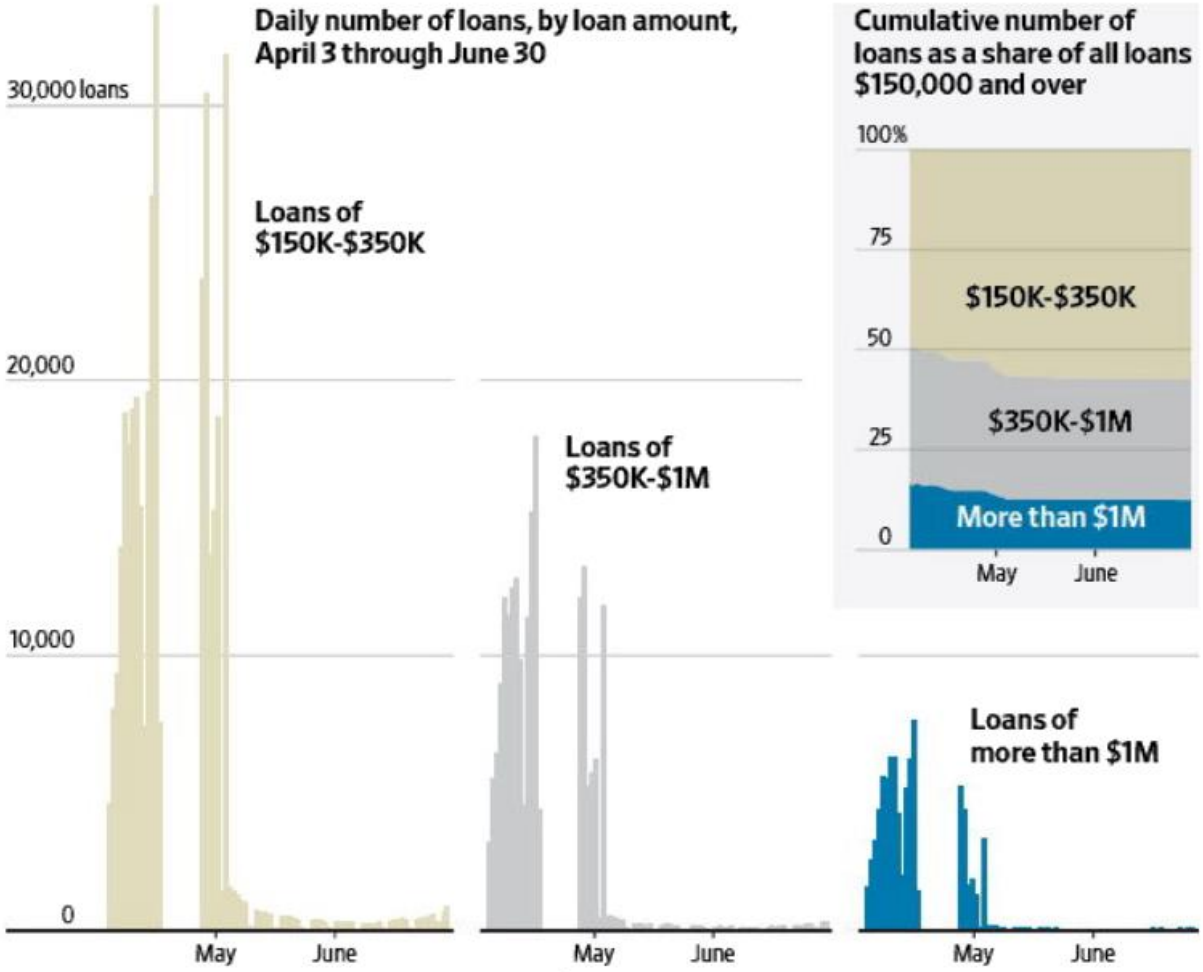
Tuff Shed's buildings are being used as makeshift offices and home-school classrooms by families stuck at home in the pandemic, said Phil Worth, vice president of marketing. The most popular office shed measures 10 feet by 12 feet, with prices starting at about $4,300.

Tuff Shed's May sales were up 26% from a year earlier and soared 90% from April, Mr. Worth said. "The amount of demand is shocking," he said.

Swath of Businesses Got Pandemic Aid

by Yuka Hayashi, Anthony DeBarros and Ryan Tracy – WSJ – Jul. 8, 2020
Chad Day contributed to this article.

More than 90 sectors each had more than 10,000 firms approved.



Note: Percentages based on number of loans and limited to those of $150,000 and more.
Source: Small Business Administration

The **government's $670 billion Paycheck Protection Program (PPP) reached** a **swath** of **small businesses across almost every sector** of the **economy**, benefiting hard-hit industries such as hotels and restaurants, as well as professional firms and construction companies that were better able to weather the crisis, new data show.

More than 90 industry sectors each had more than 10,000 firms approved for PPP loans, according to a Wall Street Journal analysis of data from the Small Business Administration, which ran the program. About **264,000 companies** in the **restaurant business got PPP money**, topping the list.

The next highest sectors were **personal-care services**; **consultants** specializing in management, science or technology; and legal services. Those three saw between **134,000** and **153,000 companies approved** for **loans**.

Blue Plate, a San Francisco restaurant, received a Paycheck Protection Program loan.

The analysis also showed that **many** of the **recipients** of **large loans** worth at **least $2 million** were **in sectors** that **avoided significant impact** from the **corona-virus pandemic** and were **able** to **have** their **employees work remotely**, such as **architectural** and **engineering**, **legal services** and **computer**-system design.

Take **computer-system design** and related services, which **lost 4.5% of jobs** from **January to June**. Firms in the sector received **803 PPP loans** worth at **least $2 million**.

In contrast, the **hotel and accommodation sector**, with a **similar number of jobs before** the **crisis**, **lost 38% of them** from **January to June**. The sector received **513 PPP loans** of at **least $2 million**.

Recipients of PPP loans in the **hotel business said** the **program helped** to **retain 980,890 jobs**, while the recipients in the **computer-system design sector said 589,532 jobs were retained**, according to the Journal analysis.

The data showed for the first time how many jobs each business reported retaining with the help of PPP funds. **In all**, the **number** of **jobs claimed** by the reporting businesses **totaled more than 51 million**.

Whether that means the **program actually saved 51 million jobs** is **less clear**, said **Eric Zwick**, a **professor** of **finance** at the **University of Chicago**.

“We don’t know what the firm would have done in the absence of the funding,” he said. “A **lot of firms who got this funding** were **only** a **little bit impacted** in terms of revenues during the crisis and **probably wouldn’t have changed** their **head count** that much.”

In a recent paper analyzing the first phase of the PPP through late April, **Prof. Zwick** and his colleagues **concluded** they "**do not find evidence** that the **PPP had** a **substantial effect on employment**."

The **U.S. unemployment rate jumped** to a **post-Great Depression high** of **14.7%** in **April**. It has since **fallen to 11.1% in June**, still sharply above 3.5% in February, the Labor Department said last week.

More than 110 industry sectors reported retaining at **least 100,000 jobs with** the **PPP funds**, according to the Journal analysis. The **restaurant industry** reported **retaining** about **5.5 million jobs**, the **most** of **any sector**.

The Journal's analysis looked at data using more general sector categories than the ones reported by the SBA. A total of about **4.9 million companies** have **received loans under** the **program**.

After restaurants, the **next two highest sectors** were **physicians' offices** and **building equipment contractors**, which **retained 1.29 million jobs and 1.26 million jobs**, **respectively**.

The Journal analysis shows that about **878,000 borrowers** either **didn't indicate** the **number** of **jobs retained** using PPP funds, **or reported retaining zero employees**.

An SBA spokesman said **businesses didn't necessarily have** to **provide** the **number of employees** to **obtain** a **loan**, **but that number** would be **required when** they **apply** for **loan forgiveness**.

There was also evidence that **larger firms** were **better able** to **navigate** the program **in** its **early days**, when panic about the pandemic was at its height. Almost all of the companies receiving **loans** of **between $5 million and $10 million**, the **maximum allowed in** the **program**, were **approved for** their **loan in April**, according to the Journal analysis.

By comparison, **60%** of **all loans** were **approved in April**, after the program began accepting applications on April 3. **Most smaller loans**, **less than $150,000**, were **approved starting April 27**, when a **second round** of **funding began**. **Congress recently extended** the **deadline** to **Aug. 8,** and it had more than **$130 billion** still **available as of June 30**.

The Trump administration, which released data on PPP borrowers this week under congressional pressure, says the total amount of **PPP loans added up to at least 72**% of **small businesses' payroll in every U.S. state. Florida topped** the **list**, with **small business loans accounting** for **96% of small businesses' payroll**.

The SBA also concluded that **27% of PPP** funds were **distributed** to **low- and moderate-income census tracts**, in line with the 28% of Americans who live in those areas. About **23%** of the funds **went** to **small businesses in areas** that the **SBA considers economically distressed, and 15**% of the funds went to rural areas.

"The top line data demonstrates that those small businesses that were able to access PPP loans were spread across the small business ecosystem, with loan

amounts of various sizes and diverse income communities represented," said Karen Kerrigan, chief executive of Small Business & Entrepreneurship Council, in a statement. "The average loan size of $106,744 is a good indication that very small firms also benefited from the program."

One industry that saw a **big boost from** the **program** while weathering the pandemic relatively well was **professional, scientific and technical services**, which included sectors like **architectural and engineering, legal services and computer-systems design**.

That industry was the **second- largest recipient of PPP loan dollars after health care** and **social assistance**, **receiving loans worth $66.43 billion**. Meanwhile, **accommodation and food services**, by far the largest victim of the pandemic measured by job losses, **received $42.1 billion**.

Those numbers **translate** to **roughly $12,500 per employee** in the **professional-services sector**, **where many** of the **workers** are **highly paid**, **compared with $4,800** for **accommodation** and **food services**, according to an **analysis by Lawrence Schmidt**, **assistant professor** of **finance** at **MIT Sloan School of Management**, and **Dimitris Papanikolaou**, **finance professor** at **Northwestern University's Kellogg School** of **Management**.

And **professional services** is the **industry where** the **ratio** of **workers who can work remotely** is **highest**, the **professors found**. For example, **78%** of **computer programmers say they can telecommute**, **while workers** in **accommodation** and **food services or transportation must nearly always be physically present** at a **workplace**.

Cyclical Companies Drive Rally in Stocks
by Caitlin McCabe – WSJ – May 26, 2020

Shares of economically sensitive companies like **manufacturers**, **energy companies** and **banks** are **powering** the **latest leg** of the **market rebound**.

The **industrials and** energy sectors logged the biggest gains in the S& P 500 last week, while the **financials** group also **rallied**.

It was a **rare period** of **out-performance** in what has **otherwise** been a **punishing year for cyclical stocks** and marked the first time since early January that industrials were the top-performing group.

Much of the recent optimism in the stock market has been driven by **signs** of **progress toward** a **coronavirus vaccine**, hopes that have propelled the S&P 500 to its highest level since early March. Some traders are betting on effective virus protection by the end of 2020, enabling economic activity to return to pre-pandemic levels.

Bargain hunters last week scooped up shares that have been **beaten down during** the **pandemic**. **Boeing** Co. surged 15%, **Halliburton** Co. rose 18% and **Bank of America** Corp. added 5.7%. All are **down** at least **35% this year**.

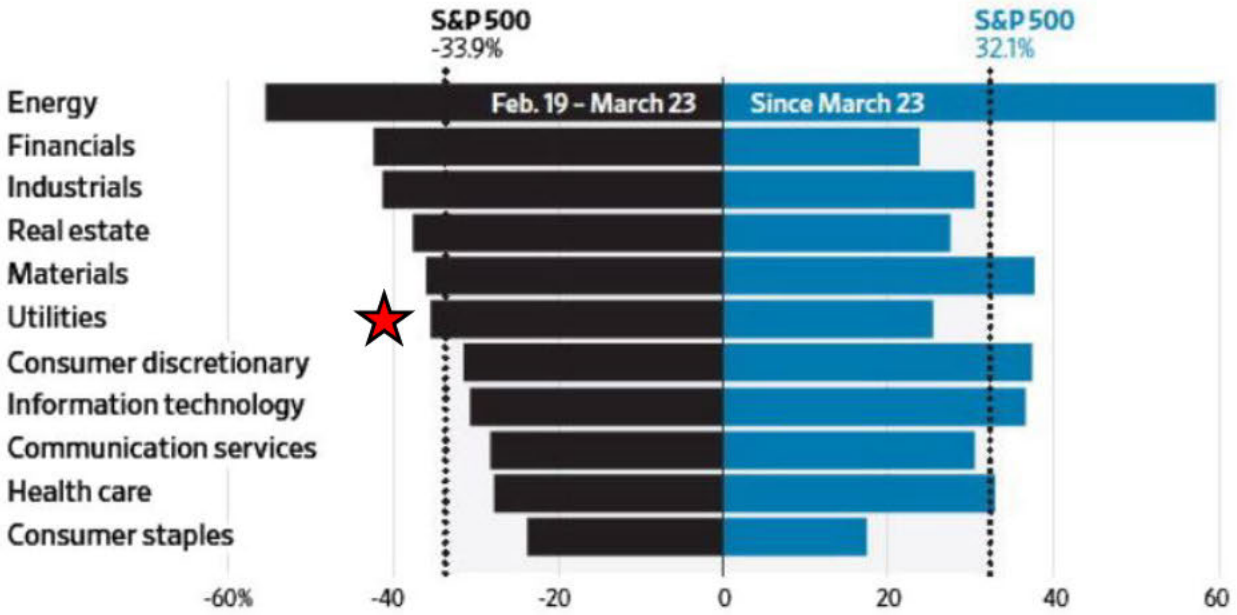
Meanwhile, the rally in big technology stocks that has fueled the market's gains over the past two months slowed. **Netflix** Inc., a beneficiary of the lockdown, lost 5.5%.

"It makes sense that people are buying cyclicals on the [vaccine] optimism," said JJ Kinahan, chief market strategist at TD Ameritrade. "But the part that makes me nervous is midmonth in June when most states [are open] … I don't

know if the reality will be able to keep up with the great expectations that we're seeing right now."

This week, investors will parse fresh data on April consumer spending and the Conference Board's index of consumer confidence for May. Both economic indicators are expected to fall. They will also review earnings reports from home-builder, Toll Brothers, Inc. and apparel maker Ralph Lauren Corp.

S&P 500 sectors performance



Source: FactSet

The **S&P 500** is **now off just 8.5% for** the **year** after **rallying** 3.2% last week and **32% from** its **late March low**. The **industrials**, **energy** and **financial** sectors of the index **all remain down 22%** or more **for** the **year**.

The **coronavirus pandemic** has **brought** the **economy** to a **near halt**, forcing more than **38 million Americans** to seek **unemployment benefits** as **stay-at home orders** have **closed businesses** and **prompted companies** to **shave** their **workforces**. As a result, **consumer spending** has **plummeted** and **manufacturing output** has **slumped**. **Analysts** are **projecting record declines** in **gross domestic product** in the **current quarter**.

Most analysts agree any meaningful recovery in the stock market will be driven by cyclical shares. But when so **much remains unknown** about the outlook for the economy, many are questioning the viability of the recent rally. A second wave of coronavirus infections, long-lasting economic fallout from stay-at-home orders and escalating tensions with China could send the economically sensitive shares tumbling, they warn. **Any stumbles could propel defensive sectors forward again** – in particular, the health-care, consumer staples and

utilities groups that tend to **shine** **in times of turmoil**. Since the stock market peaked Feb. 19, the health-care sector has fallen just 4.3%, making it the best performer of the S&P 500's 11 groups.

Analysts say the sector's resilience this year has been twofold. Traders initially flocked to the shares in part because spending on health care, like consumer staples or utilities, tends to be more stable, even when Americans tighten their budgets.

At the same time, the sector has benefited as investors bet on which biotechnology company will be first to find an effective coronavirus vaccine or treatment. Moderna, Inc. and Inovio Pharmaceuticals, Inc. both said last week that their vaccine candidates showed promise in early trials. The stocks have more than tripled this year.

Gilead Sciences Inc. is also working on a drug to fight Covid-19 and has seen some success, pushing its shares up 13% in 2020.

The stocks are also popular among institutional investors. Global health care remains the most overweight sector among fund managers, according to a May survey conducted by Bank of America Global Research, with managers' net allocation to the sector at an all-time high.

Meanwhile, some of the cyclical sectors that tumbled the most during the selloff have subsequently seen the largest gains off this year's low. Energy shares have recovered the most since stocks bottomed March 23, jumping 60%.

Some analysts and traders, however, **caution** that **some** of those **gains** could be **driven** by **short sellers rushing to cover** their **bets**. **Energy** stocks have been particularly **battered** this year as **fuel demand plunged from stay-at-home orders** and an **oil-price war between Saudi Arabia and Russia sent supply surging**. A recent curtailment in output and signs of an increase in demand for gasoline have pushed oil prices higher and lifted the shares as well. **U.S. crude** is **up by** a **third over** the **past two weeks**.

Despite some signs of a brightening economic picture, Liz Ann Sonders, chief investment strategist at Charles Schwab & Co., said she would like to see a stronger rally among financial stocks to bet the tide has turned.

She and others said it would be difficult to achieve meaningful economic recovery without the group, given how intertwined the sector is with the economy. During the nearly 11year bull market that followed the financial crisis, financials were the third-best performing group, according to Dow Jones Market Data.

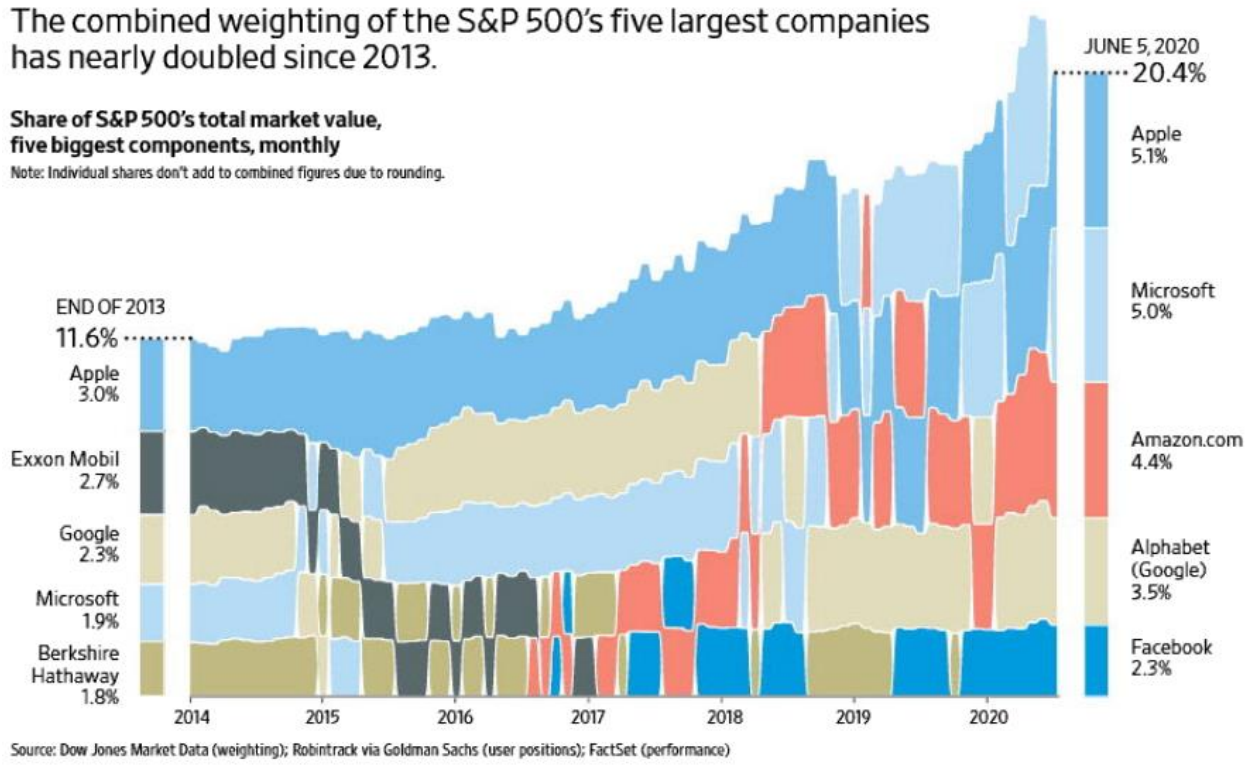
Despite last week's gains, the group's rebound from the March low is still among the smallest. Bank stocks, in particular, have been hit hard by the possibility of a surge in loan losses, as well as declining interest rates. The yield on the 10-year U.S. Treasury note settled Friday at 0.659%.

"For me, it's hard to envision a scenario where we are truly getting back on our feet economically with financials being [among] the worst performing sectors," Ms. Sonders said. "It would be very odd that we see the economy recover and not see some participation by financials."

Technology Stocks Drive Market

by Amrith Ramkumar – WSJ – Jun. 8, 2020

Individual investors are pouring money into popular technology stocks, contributing to a booming rally that is lifting major indexes amid economic uncertainty related to the coronavirus pandemic.



The faith investors have in **fast-growing tech companies** and **stimulus** measures by the world's central banks and governments helps explain how stocks have shaken off the worst U.S. economic contraction and civil unrest in decades. Many **internet** stocks favored by individuals are also popular for hedge funds and institutional investors seeking assets with attractive **growth** prospects.

Powered by advances from companies including Apple Inc. and Amazon.com Inc., the **S&P 500** has **surged** to its highest level since late February and **erased nearly all** of its **drop for 2020**.

The **Nasdaq** Composite, meanwhile, is **up 9.4% for** the **year** and on **Friday eclipsed** its **February intraday record**. The tech-laden index ended the day just below a new peak on a closing basis.

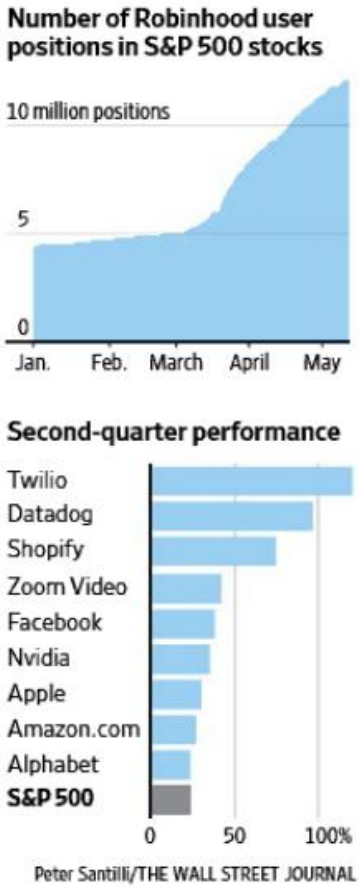
Stocks surged on **Friday** after **hiring data showed U.S. employers unexpectedly added jobs** in **May**, a hopeful sign for the economic recovery.

The Nasdaq's run underscores the strength of the recent rally in stocks, a dizzying milestone considering how quickly the index fell in February and March.

The recent gains are drawing more investors into the rally and could give rise to more milestones in the days ahead, analysts say.

Some **market professionals** remain **concerned** that **certain tech stocks** are **overvalued** and their shares will suffer if the economic fallout from the pandemic lockdowns spreads in unexpected directions.

But investors from venerable Wall Street hedge-fund managers to small traders on popular trading apps remain resolute that these tech companies will continue growing.



Their reasoning: The **coronavirus lockdowns** and **remote working** are **accelerating** many **trends** – from **cloud computing to digital payments**—that they expect to **persist beyond** the **pandemic**.

When stocks tumbled earlier in the year, trading activity by investors through brokerages such as TD Ameritrade Holding Corp. and Charles Schwab Corp. surged, helping power the recovery.

Much of that trading has been concentrated in the technology sector. If major indexes fall again, many of these investors say they are ready to buy internet shares on the cheap. That gives some market watchers confidence that stocks will recover quickly even if they slide anew.

One recent buyer is Gabriel Daniels, a 38-year-old who lives in Chantilly, Va. He has added about $2,000 worth of investments in recent weeks to his $15,000 portfolio that includes behemoths Microsoft Corp.,

Facebook Inc. and smaller tech firms such as Slack Technologies Inc. and Datadog Inc.

The CEO of a small cybersecurity – consulting firm, Mr. Daniels thinks trends like **artificial intelligence**, **5G wireless** technology and **big-data analysis** will support these stocks for years to come. "Those are the things of the future," he said. "I wouldn't say I have **FOMO** – the **fear of missing out** – but I want to keep my eyes open."

He said he has $5,000 ready to deploy in the sector if markets tumble again.

After this past week's gain, the **S&P 500 has risen 43% from** its **March 19 low,** and is **down just 1.1% for** the **year**. The information-technology sector has climbed 11% in 2020, while the communication- services and consumer-discretionary groups that house some internet shares are also positive for the year. Many popular tech stocks have risen 25% or more this quarter.

Investors in the coming week will be monitoring the Federal Reserve's latest policy statement and comments from Chairman Jerome Powell to gauge the central bank's

views on the economy. Fresh data on jobless claims will be in focus after Friday's jobs report showed the unemployment rate unexpectedly fell last month.

Left: Gabriel Daniels, CEO of a cybersecurity-consulting firm, thinks trends like artificial intelligence, 5G wireless technology and big-data analysis will support these stocks for years to come.

Still, the **economic fallout from** the **pandemic** is **hurting many companies** and **driving bleak earnings projections** for the months ahead. Some technology firms are part of a narrow group expected to continue growing, making them mainstays for many different types of investors. As individual investors pile into technology, they join hedge funds and other institutional investors also favoring the group.

Many popular stocks for ordinary investors are also common for hedge funds to hold, including Amazon, Microsoft and Facebook, Goldman Sachs Group found in a recent analysis.

"The market is so starved for growth," said Dan Morgan, a senior portfolio manager who focuses on tech at Synovus Trust Co.

After their recent gains, **Microsoft**, **Apple**, **Amazon**, **Google pa**rent **Alphabet** Inc. and **Facebook** make up **more than 20%** of the **S&P 500**. **Five years ago**, the concentration of market value in the index's largest five components was **12%**.

Their shares, and those of smaller tech companies like Zoom Video Communications, Inc. and Canadian e-commerce firm Shopify Inc., are popular among traders who frequently buy and sell shares to capitalize on short-term opportunities. Trading activity on TD Ameritrade, Charles Schwab and Interactive Brokers has increased in recent months, as has the number of accounts trading common tech holdings on the app Robinhood.

The number of Robinhood user positions in S&P 500 stocks doubled between mid-March – just before the S&P hit its low point for the year – and mid-May, Goldman found.

Reza Shahsavari started trading stocks and options that allow the holder to buy or sell shares at a certain price by a specific date on Robinhood late last year. The 38year-old manager of a medical practice in Southern California has a roughly $4,500 portfolio and frequently trades technology companies like Netflix Inc. and Nvidia Corp. He has had much **more time to trade** lately with the **pandemic keeping** him **at home**.

"It's become an **addiction** to where I want to wake up and look at the stock market in the morning," Mr. Shahsavari said.

Even for investors holding the stocks, the **big moves up and down** are unsettling. Joshua Nash sold roughly half of his $300,000 portfolio of mostly tech stocks to raise cash back in March as stocks tumbled. The 38-year-old technology consultant living in Victoria, British Columbia, has since bought more shares and now has roughly 25% of his portfolio in cash.

Some of his main holdings are Shopify, cloud-computing firm Twilio Inc., electric-car maker Tesla Inc. and digital-payments firm Square Inc.

Mr. Nash regrets unloading so many shares during the selloff and is shocked by how quickly many of these stocks have risen. He is waiting for a future downturn to buy more shares, wagering that long-term drivers of the rally will persist. “They’ve just gone through the roof,” he said.

The Cost of Investing with the Upper Crust

by Jason Zweig – WSJ, The Intelligent Investor Column – Jun. 20, 2020

Hedge-fund managers and their '**performance' fees can walk off with most of your return.**

Investment performance can be fleeting, but fees are forever. That's the lesson from a recent reversal at a prominent fund. **Chaotic markets can cancel years' worth of gains in days**, but **expenses don't dwindle when profits disappear**. And, new research shows, those **costs can be even higher than they look**.

Consider SkyBridge Multi-Adviser Hedge Fund Portfolios LLC, a fund of funds, or a basket of hedge funds that are run by about two dozen different managers. Normally you'd have to put up millions of dollars to be allowed into any of these portfolios, but you can invest in them through SkyBridge with as little as $25,000.

For many years, returns were outstanding. From 2009 through 2013, SkyBridge earned an average of 14.5% annually after expenses. That crushed the portfolio's benchmark, the HFRI Fund of Funds Composite Index, by almost 10 percentage points annually – and ended up not far behind the S&P 500's return, while offering investors a smoother ride than the stock market.

This March, however, SkyBridge lost 24.7% as the coronavirus pandemic pounded the underlying hedge funds that hold its favorite asset: structured credit, or bundles of corporate and consumer borrowings.

That one blow obliterated most of the fund's gains. As of the end of February, $100,000 invested in Sky-Bridge had grown to nearly $186,000 over the prior 10 years, more than double the average rate of return at similar hedge funds. By the end of March, that 10-year gain had shrunk to less than $137,000 – well below what you could have earned in a high-quality bond fund. The fund has since rebounded a bit, up 0.6% in April and 2.2% in May.

Fees didn't fall, however.

To SkyBridge's credit, its expenses are unusually transparent – and much lower than at many competitors. Unlike nearly all hedge funds and private investment pools, SkyBridge files detailed public disclosures.

Out of its **1.5% management fee**, SkyBridge pays approximately 0.85% annually to the brokerage and investment-advisory firms that sell the fund. Those payments, I estimate, reached $380 million over the past 10 years.

That's not all. The underlying funds bundled into the SkyBridge portfolio **pass through much higher expenses**. Their **management and incentive fees total 5%**, **pushing SkyBridge's total costs past 7.1%** – **even though** it **doesn't charge** a **performance fee itself**.

The coronavirus credit crunch in March was "a direct meteor strike on our portfolios," says Anthony Scaramucci, SkyBridge's founder and co-managing partner. "I think pre-pandemic there was a of value for everyone. The pandemic will definitely hurt our numbers, but so did 2008. But 2009-2014 was worth waiting around for, net of fees."

Yes, that's the same Anthony Scaramucci who served briefly as communications director in the Trump White House in 2017. But we're looking at **fund costs**, not politics, and your feelings about Messrs. Trump and Scaramucci – positive or negative – should have nothing to do with judgments about investment expenses and returns.

A small stake in SkyBridge – say, 3% to 8% of an investor's total portfolio – is "a return stabilizer" in the long run, says Mr. Scaramucci. Its favorite asset, structured credit, is "going to do phenomenally well in a recovery," he says, and clients who "make the decision to stay through the recovery" should be amply rewarded.

SkyBridge's fund of funds also offers a way "to get exposure to great managers like Howard Marks [of Oaktree Capital Management] and Steve Cohen [of Point72 Asset Management LP]," says Mr. Scaramucci.

He adds, "This is like an Hermès Birkin bag [which retails for thousands of dollars]. You're invested with some of the most successful money managers in the world, and you're paying additional fees for that. You could invest elsewhere for much lower costs, the same way you could get hundreds of pocketbooks at Walmart for the cost of one Hermès Birkin bag."

According to new research, though, paying up for such access comes with a twist. From 1995 through 2016, hedge-fund investors shelled out an average of 3.44% annually in management and incentive fees, according to a study by finance professors Itzhak Ben-David and Justin Birru of Ohio State University and Andrea Rossi of the University of Arizona.

The study finds that investors earned net returns of only 1.96% annually – meaning they paid $1.76 in costs for every dollar they got to keep.

Prof. Ben-David and his colleagues measured those net returns against the funds' performance hurdles – which, often, an earthworm could easily clear. When **Warren Buffett** ran a private partnership six decades ago, he **charged** a **performance fee of 25% of any gains over 6%**. Nowadays, many hedge funds take a hefty cut of any return above zero, so long as the portfolio isn't below its previous high.

Between 1995 and 2008, the hedge funds in this study produced cumulative losses, before expenses, of $1.3 billion – but still generated almost $52 billion in performance payments to their managers.

That's largely because **most hedge funds assess performance fees when they make money, but don't charge negative fees or give back past fees when they lose money**. **When returns vanish**, the **expenses don't**.

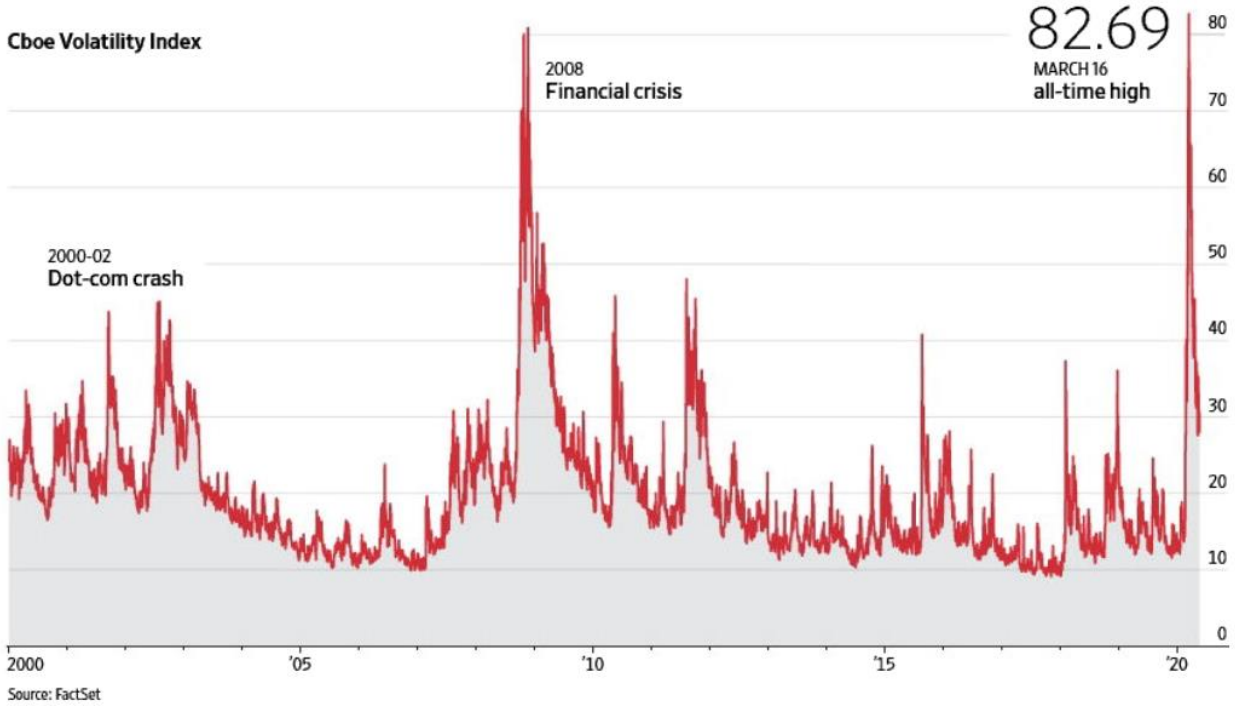
All told, **64% of** the **excess return** of the **hedge funds** in the study **went to** the **managers** in the form of **expenses**. **Of every $3** the **funds earned**, the **managers kept $2**, **leaving investors** with **$1**. That **doesn't take into account** the **extra risk** at many of these funds or the **taxes** their **investors incurred**.

Pay up, then, if you want the status of exclusive access. But remember that returns, and the prestige they offer, aren't permanent. Costs are.

The Day the Coronavirus Nearly Broke the Markets

by Justin Baer – WSJ – May 21, 2020
Heather Gillers and Gunjan Banerji contributed to this article.

Few realize how close to collapse financial system came on March 16.



An urgent call reached Ronald O'Hanley, State Street Corp.'s chief executive, as he sat in his office in downtown Boston. It was 8 a.m. on **Monday, March 16**.

A senior deputy told him **corporate treasurers and pension managers**, **panicked** by the growing economic damage from the Covid-19 pandemic, were **pulling billions** of **dollars from certain money-market funds**. This was **forcing** the **funds** to **try** to **sell** some of the **bonds they held**.

But there were **almost no buyers**. **Everybody** was **suddenly desperate for cash**.

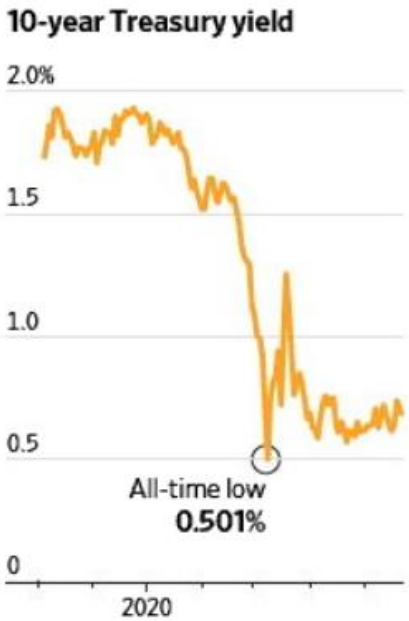
He and the deputy, asset-management executive Cyrus Taraporevala, had spoken the night before, wrestling with how investors would respond to an emergency interest-rate cut from the Federal Reserve.

Now, they had their answer. In his 34 years in finance, Mr. O'Hanley had weathered plenty of meltdowns, but never one like this.

"The market is fearing the worst," Mr. O'Hanley told him.

March 16 was the day a microscopic virus brought the financial system to the brink. Few realized how close it came to going over the edge entirely.

The Dow Jones Industrial Average plunged nearly 13% that day, the second-biggest one-day fall in history. **Stock-market volatility spiked to a record high**.

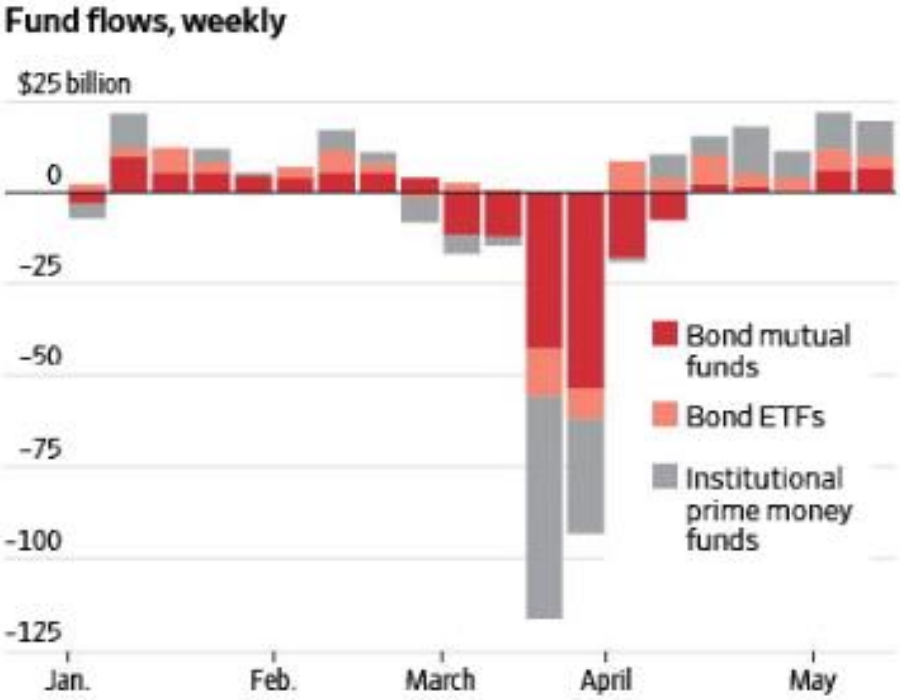


Source: Tradeweb

Investors struggled to unload even safe bonds, **like Treasurys**. Companies and government officials were losing access to the lending markets on which they rely to make payroll and build schools.

Prime money-market funds that are owned by big institutional investors and buy a lot of short-term corporate deb t– normally safe and boring – had **outflows** of **$60 billion in** the **week** ending that Wednesday, financial-data firm Refinitiv said, among the worst ever. Some $**56 billion in client money fled bond funds**.

Interest rates on **short-term corporate debt surged**, **peaking** on **March 25** at **2.43 percentage points above** the **federal-funds rate** – the **highest** it has been **since October 2008**, according to the Federal Reserve Bank of St. Louis.



The financial system has endured numerous credit crunches and market crashes, and memories of the **1987** and **2008 crises** set a high bar for market dysfunction. **But** longtime investors and those who make a living on Wall Street say **mid-March** of **this year** was far **more severe in** a **short period**. Moreover, the **stresses** to the financial system were **broader** than many had seen.

"The 2008 financial crisis was a car crash in slow motion," said Adam Lollos, head of short-term credit at Citigroup Inc. "This was like, 'Boom!' " A barrage of government

programs has since pulled the system back from collapse. This account of what happened on one of the worst days the financial markets have ever seen, from many of the executives, money managers and Wall Street veterans who lived it, shows why the rescue effort was so urgent.

Setting the Stage

The **Federal Reserve set** the **stage** for the **downturn** on Sunday, March 15. Most investors were expecting the central bank to announce its latest response to the crisis the following Wednesday. Instead, it **announced** at **5 p.m**. that **evening** that it was **slashing interest rates and** planning to **buy $700 billion in bonds** to help **unclog** the **markets**.

Rather than take comfort in the Fed's actions, many companies, governments, bankers and investors viewed the decision as reason to prepare for the worst possible outcome from the coronavirus pandemic.

A downdraft in bonds was now a rout.

Mr. O'Hanley was in a good position to see the crisis unfold. His bank provides vital, if unheralded, administrative and bookkeeping services for most of the world's biggest investors, and runs its own trillion- dollar money manager.

Companies and pension managers have long relied on money-market funds that invest in short-term corporate and municipal-debt holdings considered safe and liquid enough to be classified as "**cash equivalents**." They function almost like checking accounts – helping firms manage payroll, pay office leases and move cash around to finance their daily operations.

But **that Monday**, **investors no longer believed certain money funds were cash-like at all**. As they **pulled their money out**, **managers struggled** to **sell bonds to meet redemptions**.

Rumors circulated that some of State Street's rivals would be forced to prop up their funds. Within days, both Goldman Sachs Group Inc. and Bank of New York Mellon Corp. stepped in to buy assets from their money funds. Both firms declined to comment.

This was **bad news** for not only those **funds** and their **investors**, but **also** for the **thousands** of **companies** and **communities dependent** on **short-term l**oan **markets to** pay their employees. "If junk bonds back up, people can rationalize that away," Mr. O'Hanley said. "There's very **little ability** to **rationalize trouble in cash**."

Across the country in Southern California, the head of the debt-trading desk at investment firm Capital Group Cos., Vikram Rao, tried to make sense of the dysfunction.

Mr. Rao, who was working remotely that Monday, walked down the 20 steps to his home office at 4:30 a.m. to discover the debt markets were already in disarray. He started calling the senior Wall Street executives he knew at many of the big banks.

Executives told him that Sunday's emergency Fed rate cut had swung a swath of interest- rate swap contracts in banks' favor. Companies had locked in superlow

interest rates on future debt sales over the past year. But **when rates fell** even further, the **companies suddenly owed additional collateral**.

On that Monday, banks had to account for all that new collateral as assets on their books.

So when Mr. Rao called senior executives for an explanation on why they wouldn't trade, they had the same refrain: There was **no room** to **buy bonds** and **other assets and still remain in compliance with tougher guidelines** imposed by regulators **after** the **previous financial crisis**. In other words, capital rules intended to make the financial system safer were, at least in this instance, draining liquidity from the markets.

One senior bank executive leveled with him: "We can't bid on anything that adds to the balance sheet right now."

At the same time, the surge in stock-market volatility, along with f alling prices on mortgage bonds, had forced margin calls on many investment funds.
The additional collateral they owed banks was also booked as assets, adding billions more.

The **slump in mortgage bonds** was **so vast** it **crushed** a group of **investors** that had **borrowed from banks to juice** their **returns**: real-estate investment funds.

The Fed's bond-buying program, unveiled that Sunday, had earmarked some $200 billion for mortgage-bond purchases. But by Monday bond managers discovered the Fed purchases, while well-intentioned, weren't nearly enough. On that first day, the Fed got completely run over by the market," said Dan Ivascyn, who manages one of the world's biggest bond funds and serves as investment chief at Pacific Investment Management Co. "That's where REITs and other leveraged-mortgage products started getting into serious trouble."

That Tuesday, UBS Group AG closed two exchange-traded notes tied to mortgage real-estate investment trusts. By Friday, a mortgage trust run by hedge-fund firm Angelo Gordon & Co. had warned its lenders it wouldn't be able to meet its obligations on future margin calls.

For decades investors have eagerly scooped up **state** and **local government bonds** month after month, week after week, every week. But that **came to** a **standstill** in mid-March.

Terrified investors ditched municipal debt at fire-sale prices, underwriters canceled billions of dollars worth of deals and new borrowing stopped. There was less bond issuance in the week of March 16 than at any point during the 2008 financial crisis, the 2001 terrorist attacks or the week of 1987's Black Monday, according to Refinitiv data, adjusted for inflation.

For those few days in **March**, **investors lost faith in America's public infrastructure**. As **schools** and **universities shut down** and **airports** and **public transit systems emptied out**, the market began to question what had been previously considered gold plated bets on the core institutions that make up community life in the country.

The deep trouble in the market was clear early on the morning of March 16.

Cities and states often rely on short-term debt issued through bond dealers, who then resell the securities to investors. **Billions of dollars** of that **paper** was **up for** resale the following day. **Rates**, **which had been around 1.28%, looked like** they **could reach 6%.**

At the same time, long-term municipal-bond deals were being pulled. During that week Citigroup Inc., the second-biggest underwriter in the municipal market, wouldn't launch a single new bond.

Staff at Citigroup's municipal markets division worked in various locations that day, some from home, some from the bank's Manhattan headquarters and some from a backup office in Rutherford, N.J. Throughout the day, Citi representatives called finance officers in state and local government to deliver the bad news: Their **short-term borrowing costs** were about to **spike**. And longer deals were on hold.

Patrick Brett, head of municipal debt capital markets at the firm, was making his calls from a rustic house on a forested ridgeline in the Catskills.

That night, he would write his first of many crisis updates to state and local government finance officials around the country. In his mind, this was worse than 2008. "I don't think anyone alive has experienced anything more violent," he said in an email to The Wall Street Journal.

Citi bankers had reached out to Larry Hammel, finance chief of the Forsyth County school district, the previous week as the muni market began to dry up. The district had planned to sell nearly $150 million in bonds on March 17 so it could keep construction going on four desperately needed new schools.

'Beer or wine'

When Citi advised putting the deal on hold for a while, Mr. Hammel huddled with his chief facilities officer and the two men did the math. Without the cash infusion the district had expected from the bonds, construction would halt in July.

"It's one of those days where you just go home and say 'It's either going to be beer or wine,' " Mr. Hammel said.

He began discussions with a local bank about whether the district might be able to secure a bridge loan to keep school construction going. It **wasn't until March 30 that the bonds eventually sold**, largely thanks to government programs that brought markets back from the brink.

The **liquidity panic quickly leaked into** the **stock market**. T homas Peterffy, chairman of Interactive Brokers Group, an electronic brokerage popular with day traders, had trouble sleeping Sunday night. He would wake up, grab his iPhone and get another dire update on where **stock futures** were trading. They dropped 5%, the most allowed in a single session.

By the time Mr. Peterffy started work on Monday morning from his home in Palm Beach, Fla., many **investors** had been **forced** to **sell** their **positions because** they **didn't have enough cash on hand to maintain them**.

He repeatedly asked his team how big the losses in clients' accounts were, which bets had soured, and how much money Interactive Brokers could be on the hook for if they didn't make good.

'Fear gauge'

Adding to the tumult, Mr. Peterffy said, were the options bets against volatility.

For more than a decade, markets had been generally calm. A wildly popular bet for traders large and small was that they would remain so. But volatility had been mounting since late February. By **March 16**, it was at a roar.

The **Cboe Volatility Index**, known as Wall Street's "fear gauge," lurched higher during the day and closed at its **highest level on record** of 82.69.

Malachite Capital Management, a New York hedge-fund firm, didn't make it past Tuesday. On March 17, the firm said it would shut down, blaming the "extreme adverse market conditions of recent weeks." The **losses were** also **extreme** for others that traded on volatility. At JD Capital Management LLC, a hedge-fund firm founded by Goldman Sachs veteran J. David Rogers, the firm's Tempo Volatility Fund lost 75% or more for the month of March.

That same Monday, traders at Allianz Global Investors, a money-management arm of the German insurance giant, were struggling to restructure their own batch of disastrous options trades.

Big seller

Allianz's Structured Alpha funds had been a big seller of insurance against a market selloff in the short term and a buyer over the longer term. The strategy produced a steady income, as the fund collected premiums from investors hedging against a downturn. The funds might lose money for a month during a selloff as they restructured those short-term trades, Greg Tournant, the funds' portfolio manager, said during a May 2016 marketing video, but over time they'd make money.

"We are acting like an insurance company, collecting premiums," Mr. Tournant said. "When there is a catastrophic event, we might have to pay – very much like an insurance company. The positions we buy to protect ourselves from those catastrophic shocks – you could label those as **reinsurance**."

When the big storm arrived **in March**, though, the **strategy didn't work**.

As options contracts swung dramatically, Allianz managers scrambled to restructure their trades. They struggled to keep up; the stock market was spiraling lower at a pace the managers didn't expect.

On March 25, Allianz informed investors that two of its Structured Alpha hedge funds that managed nearly $2.3 billion would be liquidated.

Allianz executives told investors that one of the funds was down about 97% since the start of the year, one person familiar with the matter said. Even after a March 25 conference call with Allianz, some investors said, they were still unsure what exactly went wrong.

Thousands in Michigan Evacuate after 2 Dams Failed, and the Governor Warns City Could Soon Be Under '9 Feet of Water

by Rob Frehse, Kristina Sgueglia, Jason Hanna and Christina Maxouris
CNN – May 20, 2020
https://www.cnn.com/2020/05/20/weather/michigan-dam-breaches/index.html

A **rain-swollen river** has **flooded fields** and **streets** in parts of **mid-Michigan after breaching two dams**, **forcing evacuation** orders **for thousands amid** a **coronavirus pandemic** that's **posing safety challenges** Wednesday for officials trying **to provide shelter**.

The **worst** may be yet **to come**. **Downtown Midland**, a city of about 41,000 people downstream of the dams, **could e**ventually **be** "**under** approximately **9 feet** of **water**" on Wednesday, **Gov. Gretchen Whitmer** said.

"If you have a family member or loved one who lives in another part of the state, go there now," Whitmer said Tuesday night. "If you don't, go to one of the shelters that have opened across the county."

"This is a particularly dangerous situation. Seek higher ground now!" the National Weather Service said Wednesday morning in a flash flood warning statement.

The **Tittabawassee River breached** the **Edenville and Sanford dams north of Midland** on Tuesday evening after days of heavy rain. By Wednesday morning, **fields** and **roads** in Midland County were **virtual lakes**, **lapping up against businesses** and **homes**.

Evacuation orders are in effect **for** about **3,500 homes and 10,000 people**, Mark Bone, chairman of the Midland County Board of Commissioners, said he believes.

In Midland, the river Wednesday morning already was 6 feet above major flood stage and past the **previous record** of **33.89 feet**, set in **1986**.

At that height alone, the river will be flooding many homes, according to the **National Weather Service**. And it **will get higher** -- the **river could crest** at **38 feet Wednesday evening**, according to the service's advanced hydrologic prediction service.

About 150 residents – many with walkers or riding in wheelchairs – evacuated Tuesday evening from Riverside Place, a senior residence in Midland, CNN affiliate WJRT reported.

The scene wasn't easy to watch, said Toni Mclennan, a maintenance technician who checked the complex to make sure everyone was out.

Mclennan felt "sadness" and "the hope that they come back," she told the station. "I mean, especially with this pandemic and you're getting people in close quarters, it's probably that much more scary."

With the coronavirus pandemic months underway, officials in the county are juggling two public safety crises at once. Shelters have been established, and flood evacuees are being screened for the illness.

The **governor declared** an **emergency for** the **flooding**, and **said previous orders relating** to the **coronavirus** crisis are **locally suspended if they impede emergency responses** for the **flooding**.

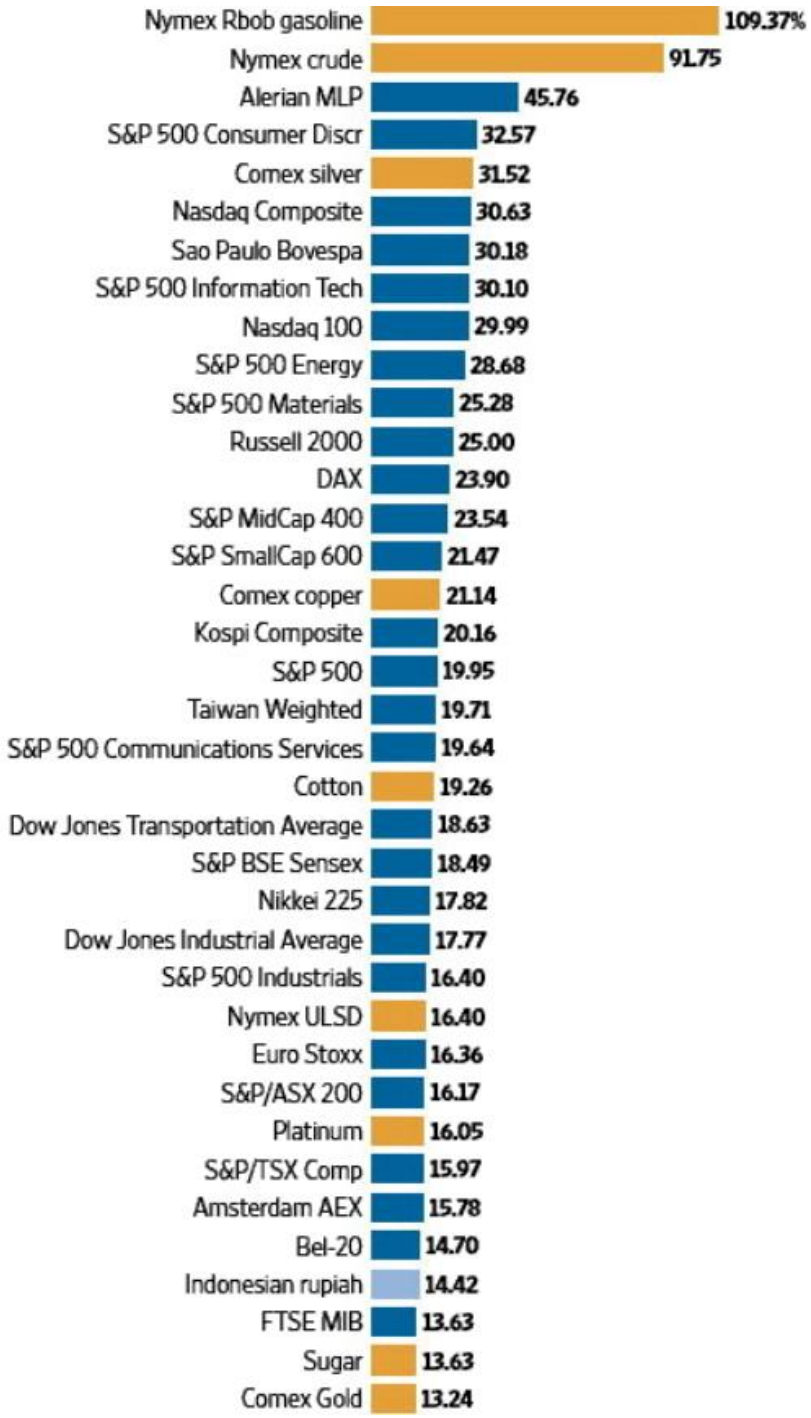
Midland, about a **130-mile drive northwest** of **Detroit**, is **home** to the **Dow Chemical** Co.

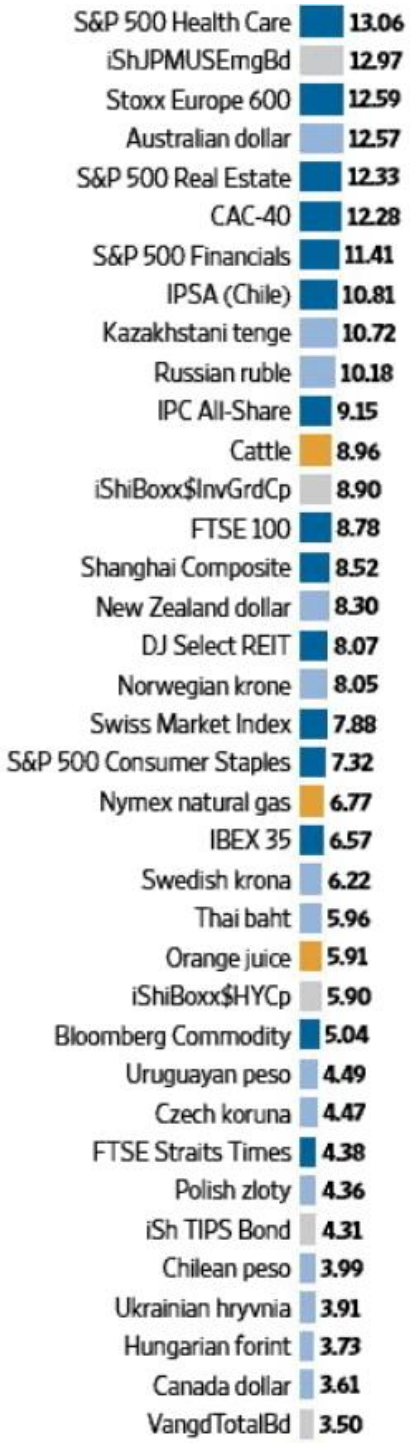
Track the Market – Winners and Losers for 2020 Q2

WSJ – Jul. 1, 2020

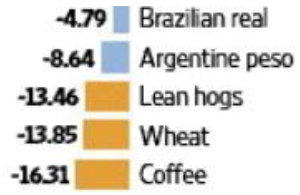
A look at how selected global stock indexes, bond ETFs, currencies and commmodities performed around the world for the quarter

Stock index | **Currency,** vs. U.S. dollar | **Commodity,** traded in U.S.* | **Exchange-traded fund**


Nymex Rbob gasoline 109.37%
Nymex crude 91.75
Alerian MLP 45.76
S&P 500 Consumer Discr 32.57
Comex silver 31.52
Nasdaq Composite 30.63
Sao Paulo Bovespa 30.18
S&P 500 Information Tech 30.10
Nasdaq 100 29.99
S&P 500 Energy 28.68
S&P 500 Materials 25.28
Russell 2000 25.00
DAX 23.90
S&P MidCap 400 23.54
S&P SmallCap 600 21.47
Comex copper 21.14
Kospi Composite 20.16
S&P 500 19.95
Taiwan Weighted 19.71
S&P 500 Communications Services 19.64
Cotton 19.26
Dow Jones Transportation Average 18.63
S&P BSE Sensex 18.49
Nikkei 225 17.82
Dow Jones Industrial Average 17.77
S&P 500 Industrials 16.40
Nymex ULSD 16.40
Euro Stoxx 16.36
S&P/ASX 200 16.17
Platinum 16.05
S&P/TSX Comp 15.97
Amsterdam AEX 15.78
Bel-20 14.70
Indonesian rupiah 14.42
FTSE MIB 13.63
Sugar 13.63
Comex Gold 13.24


S&P 500 Health Care 13.06
iShJPMUSEmgBd 12.97
Stoxx Europe 600 12.59
Australian dollar 12.57
S&P 500 Real Estate 12.33
CAC-40 12.28
S&P 500 Financials 11.41
IPSA (Chile) 10.81
Kazakhstani tenge 10.72
Russian ruble 10.18
IPC All-Share 9.15
Cattle 8.96
iShiBoxx$InvGrdCp 8.90
FTSE 100 8.78
Shanghai Composite 8.52
New Zealand dollar 8.30
DJ Select REIT 8.07
Norwegian krone 8.05
Swiss Market Index 7.88
S&P 500 Consumer Staples 7.32
Nymex natural gas 6.77
IBEX 35 6.57
Swedish krona 6.22
Thai baht 5.96
Orange juice 5.91
iShiBoxx$HYCp 5.90
Bloomberg Commodity 5.04
Uruguayan peso 4.49
Czech koruna 4.47
FTSE Straits Times 4.38
Polish zloty 4.36
iSh TIPS Bond 4.31
Chilean peso 3.99
Ukrainian hryvnia 3.91
Hungarian forint 3.73
Canada dollar 3.61
VangdTotalBd 3.50

Hang Seng 3.49
Mexico peso 3.05
New Taiwan dollar 2.91
South African rand 2.89
VangdTotIntlBd 2.61
Vietnamese dong 2.60
Croatian kuna 2.51
Icelandic krona 2.39
Philippine peso 2.25
Israeli shekel 2.18
iShNatlMuniBd 2.11
Bulgarian lev 2.10
Singapore dollar 2.03
Danish krone 1.99
Kuwaiti dinar 1.92
S&P 500 Utilities 1.84
Euro area euro 1.83
Romanian new leu 1.70
South Korean won 1.59
Dow Jones Utility Average 1.50
Swiss franc 1.45
Tel Aviv 35 0.96
Malaysian ringgit 0.72
iSh 7-10 Treasury 0.32
Chinese yuan 0.24
Macanese pataca 0.21
Cocoa 0.09
-0.07 iSh 1-3 Treasury
-0.08 UK pound
-0.20 Soybeans
-0.28 Indian rupee
-0.37 Japanese yen
-0.63 iSh 20+ Treasury
-0.66 Corn
-0.75 Pakistani rupee
-2.01 WSJ Dollar Index
-3.48 Turkish lira



*Continuous front-month contracts
Sources: FactSet (stock indexes, bond ETFs, commodities), Tullett Prebon (currencies).

THE WALL STREET JOURNAL

Treasurys Boosted by Claims, Virus Data

by Matt Wirz – WSJ – Jun. 26, 2020

Fears about a **second wave of coronavirus cases prompted investors** to **seek safety in Treasurys** and to sell bonds of companies in industries most impacted by economic shutdowns.

A rise in Covid-19 cases across the country coincided with a report Thursday morning of **1.5 million weekly jobless claims** by the **Labor Department**, roughly **unchanged** from the **two previous weeks**. U.S. stock markets fell after the report.

"The weekly claim numbers were a little higher than expected and that's a concern," said Larry Milstein, senior managing director of rates trading at R.W. Pressprich & Co. "A lot of this is about uncertainty as to how quickly people can get back to work."

The **flight to safety drove** the **yield** of **10-year Treasurys down to** around **0.674%** from a close of 0.683% Wednesday, according to data from Tradeweb. European government bonds also rallied with the yield of the U.K. 5-year hitting a record low of negative .064%, according to Tradeweb.

Corporate bonds, which rose through most of May and June, weakened as investors reduced exposure to companies that would be most affected by a new wave of economic closings in the U.S.

The price of American Airlines Group Inc.'s newly issued 11.75% bond due 2025 has dropped about 3% this week to trade around 96 cents on the dollar Thursday before rebounding to 97.25, according to MarketAxess. Casino company Golden Nugget LLC's bond due in 2024 fell about 6% to 76 cents on the dollar. Falling corporate-bond prices increase the yield that companies must pay, endangering a key source of capital for businesses.

Treasurys Gain after Jobless-Data Setback

by Sebastian Pellejero – WSJ – Jun. 19, 2020

U.S. government-bond yields fell Thursday **after** data showed the **number** of **Americans** who **filed** for **unemployment last week** was **higher than economists expected**.

The **yield** on the benchmark **10-year note** fell for the second straight day to **0.693%**, according to Tradeweb. That is down from 0.732% at Wednesday's close.

The **30-year bond yield** followed a similar path to **close** at **1.461%,** compared with 1.523% Wednesday. **Yields fall when bond prices rise**.

Labor Department data showed more than **1.5 million Americans applied** for **unemployment benefits last week**, higher than the 1.3 million economists had anticipated.

While new jobless claims have eased as states reopen their economies, **20.5 million Americans continue** to **receive unemployment benefits**, as **companies** remain **cautious** toward hiring.

"Claims are slowly, stubbornly falling back toward a 'normal' level, but it is taking a frustratingly long time and seemingly, momentum is stalling out," said Tom Simons, senior vice president and money market economist in the fixed-income group at Jefferies, in a note.

The yield on the 10-year Treasury note has retreated in recent sessions after surging to near 1% following data early in the month that showed employers unexpectedly added jobs in May.

One major driver of the decline: investors' fears that the increasing number of **coronavirus cases in** the **U.S.** will undermine efforts to restore the economy.

More than a **dozen states** have seen **confirmed cases rise** in the **past week** at a **faster pace than** the **week prior**, according to a Wall Street Journal analysis of Johns Hopkins data, with Texas, Arizona, and North Carolina reporting record daily coronavirus-related hospitalizations.

Thursday's data also included signs of economic recovery. The Federal Reserve Bank of Philadelphia's business conditions index rose to 27.5 in June from negative 43.1 in the prior month, exceeding analyst expectations. Any figure above 0 indicates improving economic conditions.

Treasury Yields End Lower on Economic Outlook

Amrith Ramkumar contributed to this article

Among the worries dragging on yields: recent resurgence of outbreaks.

U.S. government bond yields reversed an early climb and closed lower Thursday, with investors weighing persistent worries about the economic outlook against a better- than-expected monthly jobs report.

The **yield** on **the 10-year Treasury** note, a key benchmark for borrowing costs on everything from mortgages to student loans, climbed above 0.71% in the wake of Thursday morning's data, according to Tradeweb.

But it then retraced the move, **settling** at **0.670%**, compared with 0.682% on Wednesday. Bond yields rise as prices fall.

Some analysts called the reversal a **signal** that **investors believe** a full **economic recovery will take time**. The 10-year yield tends to rise and fall with investors' expectations for growth and inflation and has traded within a **relatively narrow range around 0.7% in recent weeks**, a stall many attribute to economic worries and aggressive monetary stimulus.

The 10-year yield initially climbed after data showed that the jobless rate fell to 11.1% in June and that the U.S. added 4.8 million jobs, boosting hopes that the economy will avoid investors' worst-case scenarios, but it reversed course later in the session, to snap a two-session streak of gains.

Among the worries dragging on bond yields: **concern** that a **recent resurgence** in the **pandemic** will force new lockdowns. That could **slow** the **recovery**, **prompting** the **central bank** to **keep interest rates low**. It could also limit any pickup in inflation, increasing the appeal of government debt by preserving the purchasing power of its fixed-coupon payments.

Even with big job gains in **May** and **June, employment** is still **well below levels** from **early in** the **year**.

"With the spread of the virus accelerating again, we expect the recovery from here will be a lot bumpier and job gains far slower on average," Michael Pearce, senior U.S. economist at Capital Economics, said in a note.

Asset managers, including Neuberger Berman, expect the economy will grow over the next year, but they **remain cautious**.

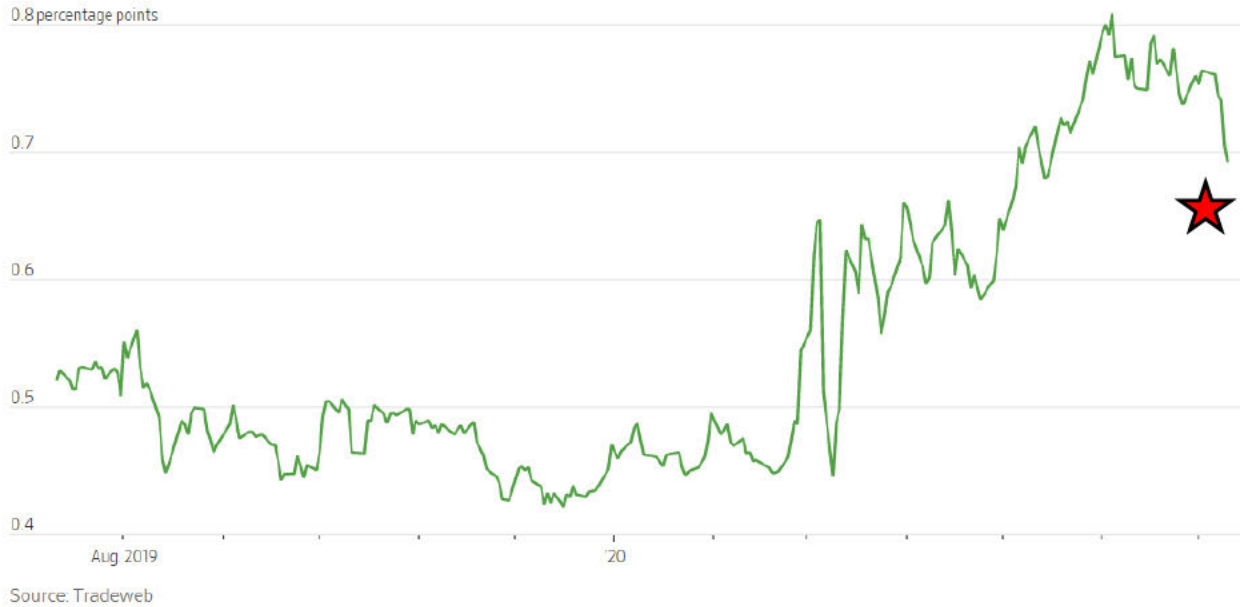
"We are unable to reconcile the size and speed of the stock market rebound at the beginning of June with what is likely to be a gradual reopening process and moderate medium-term growth," said Erik Knutzen, chief investment officer of multi-asset-class at Neuberger Berman.

Analysts expect the economy won't return to pre-crisis levels before the end of next year. Many think it will taken even longer for unemployment to return to 3.5%.

Treasury Yields Hit Lowest Levels since Covid-19 Lockdowns Eased

by Caitlin Ostroff – WSJ – Jul. 10, 2020

Investors flocked to the safety of government bonds in response to the spread of coronavirus cases.



Long-term Treasury yields fell Friday to their **lowest levels since lockdowns started loosening**, as **investors sought safe assets amid rising coronavirus cases**.

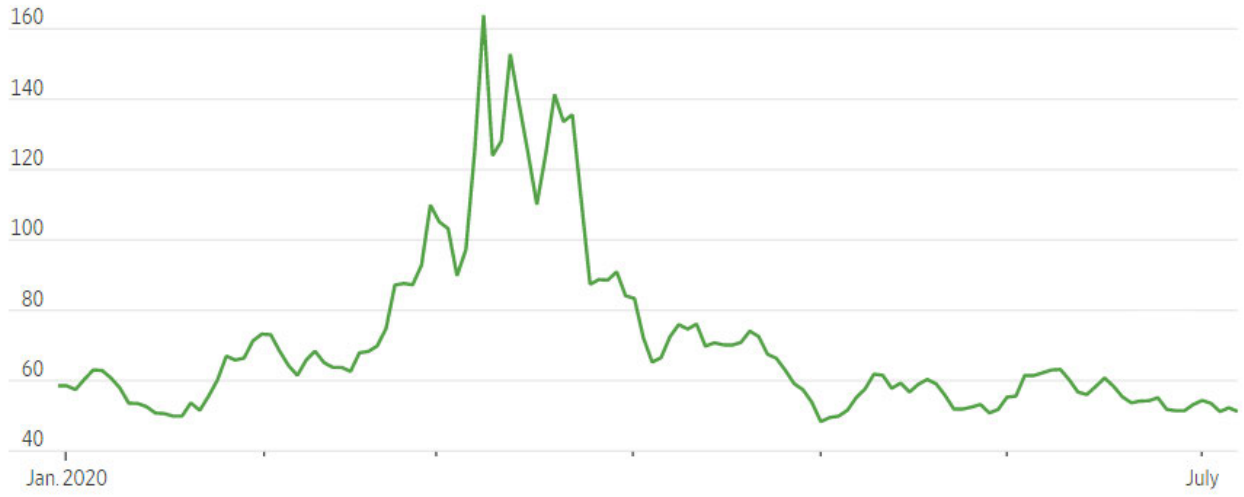
The **yield** on the **30-year Treasury fell to 1.284%**, its lowest since May 1, and the **yield** on the **10-year Treasury** hit **0.600%,** its lowest since April 24. The **spread between** the **two** is the **narrowest since May 15**, at **0.682 percentage points**, according to Tradeweb. **Bond prices rise when yields fall.**

The yield on the five-year Treasury briefly hit a record low earlier, touching 0.258%, according to Tradeweb.

A **narrowing gap between shorter- and longer-dated bonds indicates that investors expect interest rates** to **remain subdued**. The **gap** between the two had **widened when investors** were **more optimistic** about the economy emerging from the coronavirus lockdowns.

Easing Stress

The MOVE* Index, a measure of Treasury yield volatility implied by options prices on Treasurys



*Merrill Lynch Option Volatility Estimate, daily
Source: FactSet

Investors are monitoring rising coronavirus cases and the likelihood of further lockdowns curtailing the recent economic recovery. **New coronavirus cases** in the **U.S. rose by more than 63,000 Thursday, another single-day record, as hospitals in Texas, California** and **other states strained** to **accommodate** a **surge** of **new patients**.

"You have **increased uncertainty globally**, and you have **more savings**, so **investors** are **looking** to **put mone**y to **work** in a **more conservative way**," said Andrey Kuznetsov, senior credit portfolio manager at Federated Hermes. "As a result this **drives demand**" for **bonds**, he said.

Bond yields have **edged lower** even as **governments** have **issued more debt** to **fund relief efforts** to combat the economic impacts of coronavirus. In the U.K., the yield on the five-year gilt, as British government bonds are known, hit a record low Thursday of minus 0.08%. Investors there anticipate that the Bank of England will implement negative policy rates in the future.

Despite continued demand for safe assets, **volatility** in **U.S. bond markets** has **fallen** to **near levels seen before the coronavirus pandemic**. **Bank** of **America's MOVE Index**, a **measure** of **Treasury yield volatility implied by options prices**, **fell** to **50 on Friday** after having surpassed 150 at the height of the March selloff.

This is in large part **due** to **measures taken by** the **Federal Reserve** and **other central banks** to **backstop credit** and **funding markets**, Mr. Kuznetsov said.

Left: Federal Reserve Chairman Jerome Powell testified before the House Financial Services Committee on Capitol Hill on June 30.

In **stock markets**, **by contrast**, a popular measure of future volatility known as the **Cboe Volatility Index**, or the **VIX**, has **remained elevated**. **Stock market investors worry** that **markets could return** to their **dramatic swings** from earlier in the year. **Further lockdowns** to stem the spread of coronavirus **could rattle fragile investor confidence**, **driving demand** for **safer assets**, **analysts and investors said**.

Treasury Yields Remain Near Lows

by Julia-Ambra Verlaine – WSJ – Jun. 30, 2020

U.S. government yields clung near recent lows even as stock markets rebounded.

The yield on the benchmark **10-year U.S. Treasury note closed at 0.636%,** according to Tradeweb. That is **unchanged from Friday**, when yields posted the largest three-week decline since the week ended April 3. The two-year yield ended the day at 0.158%, down from 0.160% Friday.

Yields declined in recent sessions, with investors focused on how mounting **coronavirus cases** will hit efforts to restart the economy. Recent data shows an **uptick world-wide**, with cases passing 10 million over the weekend, and the **unemployment outlook** remains **uncertain**.

"Markets tend to focus on one issue at a time," said Jean Boivin, head of the BlackRock Investment Institute, the think-tank arm of the asset manager.

Deutsche Bank analyst Torsten Slok **estimates** the **U.S.** would **need** to **create 30 million jobs** to **get** the **employment- to-population ratio back to** where it was at its **peak in 2000**.

Employment is down by nearly 20 million jobs, or 13%, since February, the month before the pandemic prompted states to shut down huge segments of their economies.

Traders are looking at alternative data to form a clearer picture on re-openings and new cases in states. According to JPMorgan analysts, Chase card data indicated that the **level** of **restaurant spending three weeks ago** was the **strongest predictor** of the **rise** in **new virus cases over** the **subsequent three weeks**.

"The resurgence of infections highlights that the reopening of the economy cannot be delivered overnight," said JPMorgan's Matthew Jozoff, in a note to clients.

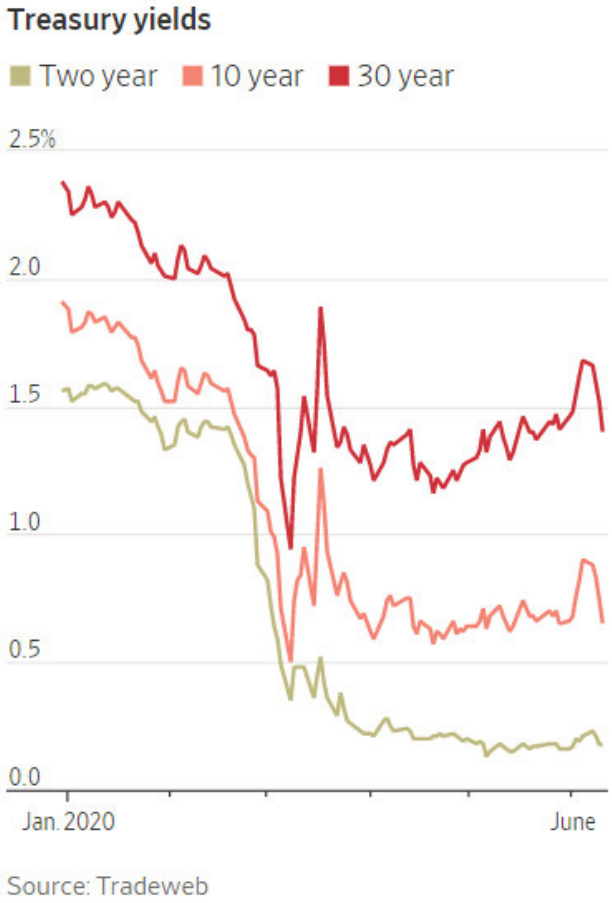
Still, even if the economic picture brightens, bond investors are skeptical about whether short-term yields have room to move higher. That is because of **unprecedented monetary** and **fiscal policy** deployed to get money into the hands of American businesses and consumers.

Treasury Yields' Retreat Signals Economic Woes

by Julia Ambra Verlaine and Sam GoldFarb – WSJ – Jun. 12, 2020

Investors' bets on worst-case scenarios haven't panned out, but hopes for a return to normalcy have been upended as well.

A selloff in U.S. government bonds that pushed yields to the highest levels since March petered out almost as quickly as it started, a sign economic pessimism and aggressive monetary stimulus remain powerful forces suppressing longer-term interest rates.



The **yield** on the benchmark **10-year U.S. Treasury note dropped back below 0.7% Thursday**, after mounting **coronavirus cases upended investors' hopes** for a **return** to **economic normalcy**. The move followed another steep decline Wednesday, after the **Federal Reserve said** it had no **plans to raise short-term rates through 2022** and would **continue buying Treasurys** at a pace of at **least $80 billion a month**.

A critical benchmark for borrowing costs on everything from mortgages to student loans, the 10-year yield has remained stuck for months near record lows following the Fed's sweeping intervention to quell violent price swings earlier in the year. But it jumped as high as 0.959% last week, according to Tradeweb, after a series of data reports suggested the economy might be on stronger footing than expected.

That prompted investors to trade out of bets on worst-case scenarios, such as sustained mass unemployment or a general decline in prices, known as deflation. Bond-trading desks said volumes were high as asset managers scrambled to unwind positions and reassess the landscape.

But the move higher in yields screeched to a halt this week as such worries resurfaced. Despite last week's data and a stock market that has recouped much of its pandemic-era losses, many investors still see little reason to expect a big surge in economic growth and inflation, which would erode the value of their fixed coupon payments.

"Rates probably had gotten a little ahead of the data, and [Wednesday's] Fed meeting reminded the market that they aren't going anywhere anytime soon," said Robert Dishner, a portfolio manager at Neuberger Berman. He's holding on to Treasury

inflation-protected securities and thinks rates in longer maturities will remain stuck in a narrow range. “The recovery is likely to be uneven.”

Many investors are also confident the Fed will do what it takes to keep long-term rates from rising much higher because higher yields translate into steeper borrowing costs for businesses and consumers, potentially crimping economic activity.

Everything officials released on Wednesday, from their policy statement to their interest-rate forecast “has enhanced the Fed’s commitment to keep rates low,” said Jay Barry, head of USD government bond strategy at JPMorgan.

ehind last week’s rise: hiring data that showed the U.S. unexpectedly added jobs in May, a sign the labor market is recovering after shutdowns earlier in the year. Other reports released around the same time showed declining activity in the manufacturing and service sectors but at a slower pace than in April.

That left asset managers debating whether the jump reflected the same hopes for a rapid economic rebound that carried the Nasdaq Composite to a fresh highs, or if investors were simply reassessing how long it would take to get U.S. consumers back on airplanes and into restaurants.

“I err on the side that this is an unwind of the deflation trade,” said Rick Rieder, chief investment officer of global fixed-income at BlackRock Inc.

The moves in bonds have contrasted with those in stocks, which have rallied for weeks even while ultralow Treasury yields signaled deep concerns about the economy. The 10-year yield tends to rise when people expect economic growth and inflation and to fall when the outlook darkens.

And investors’ recent appetite for riskier assets has extended beyond stocks. As of Wednesday, the extra yield investors demand to hold U.S. speculative-grade corporate bonds over U.S. Treasurys was just 5.74 percentage points – down from 7.57 percentage points on May 15, according to Bloomberg Barclays data.

Other factors are also in place that could theoretically push yields higher—notably the record levels of debt the U.S. Treasury is issuing to fight the economic damage caused by the pandemic and months-long lockdowns.

After initially leaning on short-term Treasury bills to fund the trillions of dollars in economic-relief programs passed by Congress, the Treasury Department in early May announced an even larger shift to longer-term bond sales than many analysts were expecting – increasing the size of regular 10-year note auctions by $5 billion and 30-year bond auctions by $3 billion.

Supply pressures have further been exacerbated by a deluge of bond sales from companies looking to stock up on cash as they try to weather the economic downturn. Nonfinancial companies have sold more than $650 billion of investment-grade bonds in the U.S. market since the start of March, shattering previous issuance records, according to Dealogic.

Some analysts argue that longer-term Treasury prices could still drop sharply again if economic data improve and the supply of new bonds overwhelms what the Fed is willing to purchase.

“The key risk for fixed income remains that policy makers lose control of the long ends giving rise to a ‘tantrum’ selloff, given record issuance and better data,” strategists at Oxford Economics wrote in a Thursday note.

Treasury Yields Rise in Volatile Session

by Sebastian Pellejero – WSJ – Jun. 17, 2020

U.S. government-bond yields swung wildly Tuesday amid conflicting signs about the pace of the global economic recovery from the coronavirus pandemic.

The **yield** on the benchmark **10-year Treasury note** rose as high as 0.783% in early trading, before paring its climb to **0.754% at** the **market close**, according to Tradeweb, from 0.701% at Monday's close. **Yields rise when bond prices fall**. The **30-year yield** followed a **similar path**, **finishing** the trading **day** at **1.538%**, from 1.448% Monday.

Yields climbed early in the session **after** the **Commerce Department said** renewed shopping at reopened stores prompted a **record 17.7% increase** in **retail sales** in **May**, though total spending remained below levels prior to the pandemic.

The increase followed three consecutive months of declining retail sales, including the largest monthly drop on record in April, when retail spending fell 14.7% on a revised basis.

Investors welcomed the data as the latest sign that the worst of the economic shock from the coronavirus has passed.

Further buoying their optimism: reports that President **Trump's administration** is preparing a **nearly $1 trillion spending plan** on **infrastructure**.

Yields pared their climb sharply, **however**, after signs of rising coronavirus cases and new warnings from **Fed**eral Reserve **Chair**man Jerome **Powell** about the **economic outlook**.

Mr. **Powell** said Tuesday that the **U.S. economy faces significant long-term damage from higher unemployment** and a **wave of small-business failures**, **despite** **recent** **signs of improvement**.

"If not contained and reversed, the downturn could further widen gaps in economic well-being that the long expansion has made some progress in closing," Mr. Powell said in testimony presented to the Senate Banking Committee on Tuesday.

U.K. Regulator Orders Big Four to Separate Audit Practices by 2024

by Nina Trentmann – WSJ – Jul. 6, 2020
Sabela Ojea contributed to this article.

Under new rules, audit businesses will have to publish their own profit and loss statements, separate from the overall firm's.

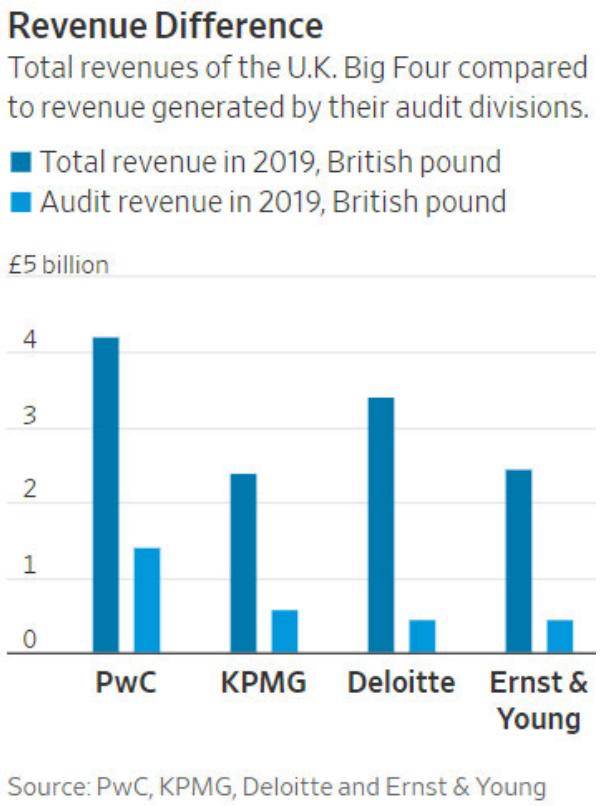
London skyline. The Financial Reporting Council said it aims to reduce potential conflicts of interest and boost the quality of audits in the U.K.

A U.K. regulator on Monday told the country's biggest professional services firms to draw up plans for separating their audit businesses by Oct. 23 and for the work to be completed **by mid-2024**.

The **Financial Reporting Council** – the **U.K.'s accounting and audit watchdog** – said it aims to **reduce potential conflicts** of **interest** and **boost** the **quality** of **audits** in the U.K. as the country embarks on its future outside of the European Union.

The measures come after a string of corporate failures, including at construction giant Carillion PLC, coffee chain operator Patisserie Holdings PLC and travel company Thomas Cook Group PLC.

The FRC listed 22 principles the "**Big Four**" – **Deloitte**, **Ernst & Young**, **KPMG** and **PricewaterhouseCoopers** – will have to adhere to by June 30, 2024. Under the principles, the Big Four **will have to ring-fence their audit practices** and **ensure** that **audit partners spend** the **majority** of their **time on audits**.



Audit practices will need to **publish** their **own profit** and **loss statements**, **separate from** the **overall firm's**, and make sure there are **no material, structural cross-subsidies from other parts** of the **business**, the **FRC said**.

Audit partners' pay will be based on their contribution to audit practice profits, the **FRC said**. The regulator also is asking professional services firms to be **more transparent** about their audit businesses **and** for audit professionals to **demonstrate ethical behavior** and **professional skepticism while conducting** their **work**.

The FRC is adopting recommendations made by other regulators, lawmakers and accounting experts in previous years, though not one proposing that audit practices be funded by audit fees only.

The **regulator** also **stopped short** of **ordering** a **full, structural breakup** that would have required audit entities to be spun-off into separate legal entities.

"Operational separation of audit practices is one element of the **FRC's** strategy to improve the quality and effectiveness of corporate reporting and audit in the United Kingdom following the Kingman, **CMA** (**Competition and Markets Authority**) and Brydon reviews," said FRC Chief Executive Jon Thompson.

The **changes don't apply** to **smaller audit and accounting firms**.

The **Big Four** in **recent years** have **generated** a **growing part** of their **revenue** with **non-audit services**, including **consulting**, and have **offered** them **to** many of their **audit clients**. Even though the firms have taken steps to stop selling nonaudit services to audit clients, **concerns** around **conflicts** of **interest** and **financial dependency** of **audit practices remain**.

Monday's announcement is part of a broader effort to overhaul the structure and oversight of the U.K. audit sector. The **FRC** is set **to become part of** a new statutory regulator called the **Audit, Reporting and Governance Authority**, which will be **equipped** with a **bigger toolbox** to **rein in audit firms**.

The Big Four, academics and industry representatives welcomed the changes but said more actions are needed to improve the quality of audits in the U.K.

KPMG suggested clearer responsibilities for boards, directors and management, among other changes. "Serious consideration should be given to the introduction of a U.K. version of the **Sarbanes-Oxley Act**, which was effective in introducing expanded **requirements** for **all U.S. public company boards**, **management** and **public accounting** firms in **2002**," said Jon Holt, head of KPMG's U.K. audit business.

Michael Izza, chief executive of the Institute of Chartered Accountants in England and Wales, said the announcement provided a useful framework for running an audit firm. "However, it will do little to improve quality or choice in the market," Mr. Izza said.

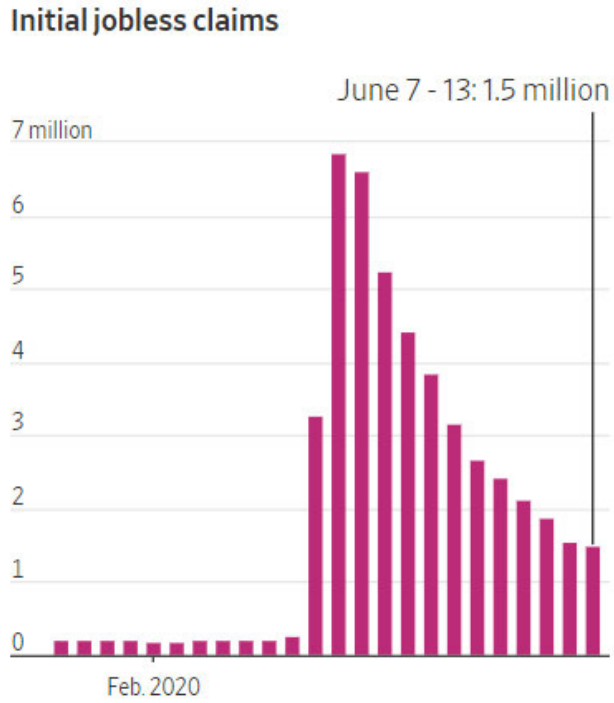
Audit firms need to overhaul their attitudes toward clients, said **Karthik Ramanna**, a **professor** of **business** and **public policy** at the **University** of **Oxford's Blavatnik School of Government**. "The big issue with audit quality is the culture within **audit firms**: the **culture** is **too deferential** to **clients' senior management**," said Mr. Ramanna, who last year issued a report suggesting independent, external remuneration committees for determining audit partners' pay.

Increasing automation of audits could help resolve some concerns, said Fiona Czerniawska, managing director of advisory firm Source Global Research. "Greater automation of the audit process is likely to result in significant changes to both buyers and suppliers over the next five years," she said.

U.S. Unemployment Claims Edge Lower, but Remain Historically High

by Eric Morath – WSJ – Jun. 19, 2020

At 1.5 million, fewest weekly applications since mid-March, but shows pace of layoffs is no longer significantly easing



Note: Seasonally adjusted, latest figure is preliminary
Source: Labor Department

The **number of workers applying for** and **receiving unemployment benefits** has **stabilized at historically high levels**, signs that while the labor market is healing **hundreds** of **thousands** of **workers** are **still losing** their **jobs each week**.

New applications for benefits edged **lower by 58,000 to** a seasonally adjusted **1.5 million** in the **week ended June 13,** the Labor Department said Thursday. **While** it is the **fewest** weekly applications **since mid-March**, it also showed the **pace** of **layoffs** is **no longer significantly easing.**

The number of **Americans receiving benefits** payments **fell** by 62,000 **to 20.5 million** in the **week ended June 6**. Those continuing claims are reported with a one-week lag. A stable level of people on benefit rolls suggested that new layoffs are being offset by employers hiring or recalling workers as states have allowed more businesses to reopen in recent weeks.

Other signs of economic growth have emerged, including a May rebound in retail spending that followed record declines. But with the economy having slipped into **recession** this year, many **firms** have remained **cautious** about rehiring, leaving millions of people out of work since the pandemic hit.

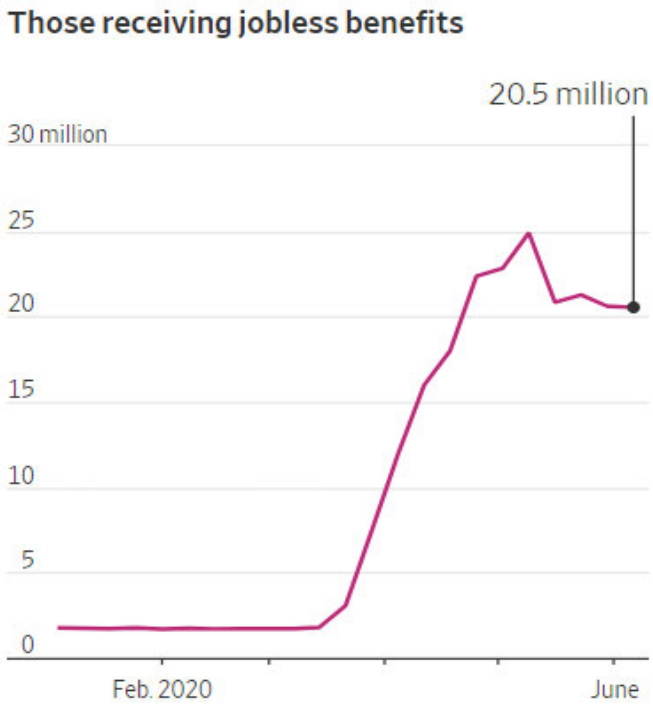
Employers added to payrolls in May but only offset about one in 10 jobs lost in April and March. Recent data indicate a higher volume of workers are moving in and out of jobs, said Roiana Reid, an economist at Berenberg Capital Markets.

"You're going to see **elevated levels of layoffs because some businesses** will **permanently close**," she said. "But hiring and rehiring will outweigh that this summer, especially as you see big cities, such as New York, reopen."

The level of **new weekly jobless claims** is well **down** from a peak of 6.9 million in late March, according to the Labor Department. **But** the **recent total of 1.5 million** is **still well above** the **highest week on record before this year**: **695,000 in 1982**.

Most states reported fewer unemployment applications last week, but some, including Texas, New York, New Jersey and Nevada, reported an increase in initial jobless claims.

The number of **Americans receiving continuing unemployment benefits** has **plateaued near 20 million** for **several weeks** and is **down** from a **peak** of nearly **25 million** in early **May**, according to the Labor Department. **But joblessness** remains at **historically high levels**. **Before this year**, the **most Americans receiving unemployment benefits** in a **single week** was **6.6 million in 2009**, according to Labor Department records **back to 1967**.



Note: Continuing claims; seasonally adjusted
Source: Labor Department

The economy remains unsettled, said Michelle Holder, an economist at John Jay College in New York. She said unemployment-insurance applications and recipient levels were likely to only slowly ease in the coming weeks now that the initial wave of layoffs has passed.

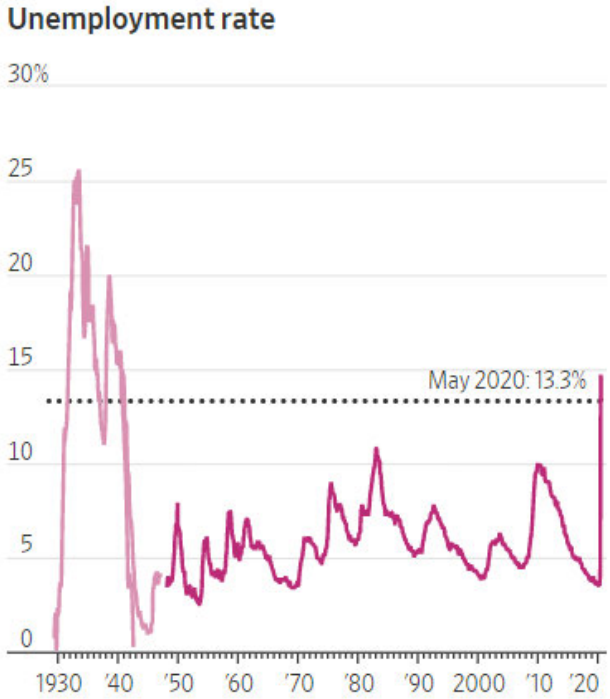
"It will be a while before we reach Great Recession levels," she said, referring to the 2007-2009 recession, "much less pre-pandemic levels."

Unemployment benefits have been **expanded** to those who were previously ineligible for such aid, including self-employed and gig-economy workers. Last week, 761,000 sought benefits through that program, which is accounted for separately from the regular unemployment insurance program and not adjusted for seasonality. For the week ended May 30, the latest available data, the number receiving payments through the program fell by 445,000 to 9.3 million.

Unemployment Rate Fell to 13.3% in May

by Josh Mitchell – WSJ – Jun. 5, 2020
Eric Morath contributed to this article.

Payrolls rose by 2.5 million, suggesting jobs are returning.



Note: Seasonally adjusted. Unemployment before 1948 is based on two measures covering 1929-1942 and 1940-1946.
Sources: National Bureau of Economic Research (1929-1946); Labor Department (1948-2020)

The **U.S. jobless rate fell to 13.3%** and **employers added 2.5 million jobs in May**, early signs the labor market is mending as the economy started to reopen following lockdowns related to the coronavirus pandemic.

Employment rose sharply across industries, including leisure and hospitality, construction, education and health services, and retail, the Labor Department said.

"These improvements in the labor market reflected a limited resumption of economic activity that had been curtailed in March and April due to the coronavirus (COVID-19) pandemic and efforts to contain it," the department said Friday in a release.

The **jobless rate fell from 14.7%** a **month earlier**, which was the **highest on records** dating **from 1948**. A broader measure of unemployment – which includes part-time workers and those who gave up looking for jobs – fell to 21.2% from 22.8% a month earlier.

The **economy had lost 22.1 million jobs combined** in **March and April when states and localities ordered many businesses** to **shut down** to **combat** the **spread** of the **virus**. In **May**, with **some** areas starting to reopen, some **businesses rehired workers**.

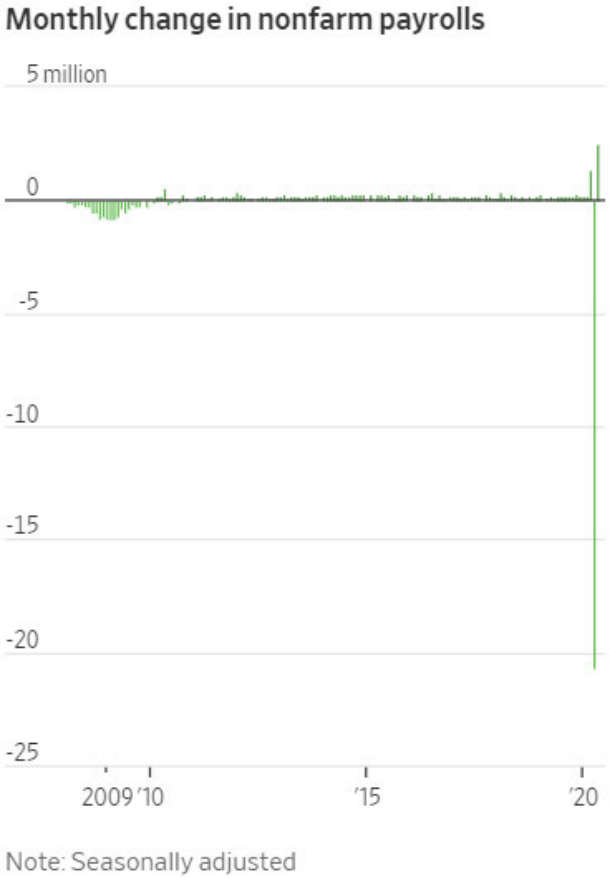
"The bounce-back started earlier than most expected, but don't get too excited about this one month of data," Nick Bunker, economist for hiring website Indeed, said in a note It's **not clear how enduring this will be**."

Despite the gains last month, the **jobless rate is still exceptionally high,** and **21 million workers remained unemployed**.

Other data suggest the labor market stabilized in recent weeks, though it likely suffered **another setback from riots and looting** after George Floyd was killed in police custody May 25 in Minneapolis.

Friday's report showed the **unemployment rate** was **uneven across racial groups**.

The **unemployment rate** for **African-Americans** rose by 0.1 percentage point in **May** to **16.8%.** The rate for **Asians** increased to **15%** from 14.5% in April. The rate for **Latinos** was **17.6%** in May, down 1.3 percent points from April's record high. The rate for **white** workers fell 1.8 percentage points in May to **12.4%**



The jobless rate fell for both women and men, but the rate for **women** was higher, **14.5% versus 12.2%** for **men**. In February, before the economic shock due to the pandemic began, the unemployment rate was slightly lower for women, 3.4% compared with 3.6% for men.

Of those unemployed due to job loss, 84% reported themselves as on a temporary layoff, meaning they expect to return to their prior employer within six months. While that is historically high, the share is down slightly from 88% in April.

Some industries that were the quickest to lay off workers in March added many of those workers back in May.

Penn Quarter Sports Tavern in Washington, D.C., laid off all 28 employees in early March, after city leaders ordered nonessential businesses to close during the pandemic. When the city began the first phase of reopening last month, the restaurant rehired about half of his employees in the hopes of reopening the bar this week, said owner Mike Brand.

But protests and looting prompted him to board up his business and delay the opening by at least a week.

"We had every intention to be operating right now but now we're back stuck in the mud," Mr. Brand said. "This extra week, maybe two with the riots, it's taking a huge financial chunk."

He said he has been trying to rehire more of his former employers, but he has run into a hurdle. Many of his servers and bartenders have declined offers to come back to work, he said. Some are fearful of catching the virus; others don't want to give up their unemployment benefits, which currently pays them more than they would earn at the restaurant. He believes that as enhanced unemployment benefits expire he will have an easier time finding workers.

Research confirms that the typical worker on unemployment is earning more on unemployment than he or she had been at work, due to enhanced benefits and stimulus money provided by Congress, said Becky Frankiewicz, president of Manpower Group North America, a job-placement company.

The **Congressional Budget Office**, in a Thursday letter to members of Congress, said it estimated **expanding enhanced jobless benefits through January 2021 wou**ld mean **five in every six claimants** would **make more money from unemployment insurance than from work**. The program pays **workers** an **extra $600 a week** and is currently set **to expire in July**. Lawmakers are debating whether to extend it as part of a new stimulus bill.

Those benefits are a big reason that, despite, the widespread job loss, many economists believe the economy will rebound late this year and many jobs will be recovered. **Forecasting** firm **Moody's** Analytics projects the **unemployment rate** will fall to **8.5% by year-end** and that the **annual job loss** will **settle at 8 million**.

Ms. Frankiewicz said there is a hopeful sign the labor market has turned a corner: Industry data her company analyzed showed job postings rose in the past week by 10%. "As states start to reopen we're seeing an increase in demand," she said. "When will we be back? We got here overnight. We won't return overnight."

One big uncertainty is just how long some businesses will be able to hold on, given that any recovery is likely to be painfully slow. For example, many restaurants that are reopening are operating at a much smaller capacity to comply with social distancing rules. In D.C., those rules mean Mr. Brand's tavern will only be able to seat people outdoors.

In **Portland**, Ore., Kate Rafter had spent five weeks on a furlough when she returned to work the first week of May at a nonprofit that takes children on field trips around the Pacific Northwest. Two days after she returned, her boss told her she was being laid off. Many parents had canceled plans to send their children on trips given the risk of catching the virus. The nonprofit said it could no longer afford to keep Ms. Rafter on as a business-systems analyst.

She had loved the job, which offered decent pay and great health benefits, and she had planned to move out of her parents home and into a new place of her own. Now, she is living off unemployment benefits and the stimulus check Congress provided to many households.

She is hopeful, though, because she has seen a number of job postings in her field. "I think I'll be able to find something," she said. She has spent recent weeks knitting hundreds of masks which she has donated, and decluttering her parents home.

Unprecedented Demographic Change Will Shape Credit Markets Through 2030

by John Lonski, Chief Economist
Moody's Capital Markets Research, Inc. – Jun 25, 2020

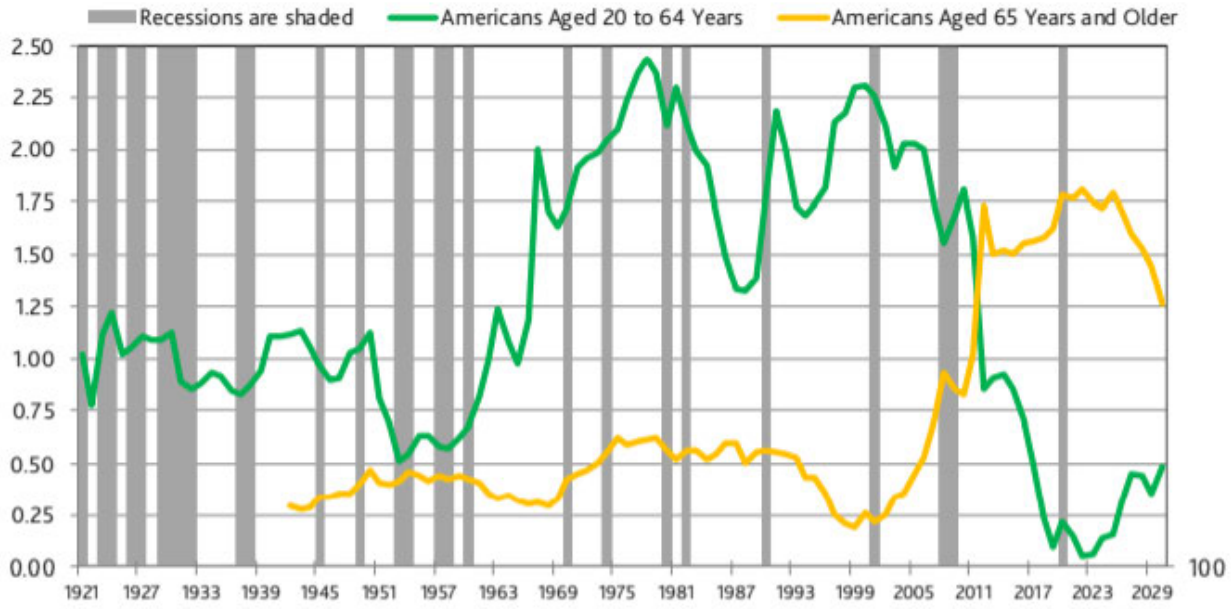
Even without COVID-19, **long-term prospects** for **U.S. economic growth fell considerably short** of what held during the **second half** of the **20th century**. **Only if** the average annual rate of **labor productivity growth far exceeds** its **1.2% rise** of the **10 years ended 2019 might** the **average annual rate** of **U.S. real GDP growth well surpass 2% through 2030**. **Achieving labor productivity growth** of at **least 2%** on a **recurring basis** probably **requires another wave** of **technological innovation comparable** to the introduction of **internet technology** during the late **1990s**.

Partly in response to the implementation of new communications and computing technologies, **labor productivity advanced** by an extraordinarily rapid **3.0% annualized**, **on average, during 1997-2000**. In turn, the breakneck **rate of productivity growth supplied** a **4.5% average annualized surge by U.S. real GDP**.

In addition, **U.S. economic growth** during **1997-2000** was **spurred** by very **favorable demographic changes**. During **1997-2000**, the **number** of **Americans aged 20 to 64 years** (a proxy for the U.S.' working-age population) **grew** by an outsized **2.25 million annually**, **on average**, while the **number** of those **aged 65 years and older rose by merely 227,000 annually**.

By **contrast**, the **demographic outlook** for the **next 10 years differs drastically** from what held amid the very rapid U.S. real GDP growth of 1997-2000. **For the 10 years ended 2030**, demographers projected **average annual increases** of **only 241,000** for the number of **Americans aged 20 to 64 years** and **1.676 million** for those **older than 64 years**. Within the latter category, the number of **Americans aged** at **least 80 years** is expected to **increase** by **607,000 annually** on **average through** the **2030s**. Thus current projections have the 607,000 average annual increase by the **80-years-and-older age cohort topping** the 241,000 of the **20-to-64-years age cohort**, or what **traditional**ly captures the size of the **workforce**.

Figure 1: Unprecedented Aging of U.S. Population Will Rein In Growth, Inflation, and Interest Rates Post COVID-19 Recession
actual & predicted annual increases in millions of people
sources: Census Bureau, NBER, Moody's Analytics



Do the FOMC's Long-Term Rate Forecasts Aim to Rein in Speculation?

In all likelihood, the **unprecedented aging** of the **U.S. population will rein in U.S. economic growth**, **inflation**, **and interest rates into** the **2030s**. Though the **Fed**eral **O**pen **M**arket **C**ommittee's **long-term forecast** of **1.8% U.S. real GDP growth** seems **plausible**, the accompanying **long-term forecasts** of **2% for PCE price index inflation** and **2.5%** for the **federal funds rate may prove** to be **too high**. The **more appropriate long-term projections** might be **1.7% for PCE price inflation** and **1.5% to 1.75%** for **fed funds**.

During the **five years ended December 2019, fed funds averaged 1.10%** amid what was a livelier demographic backdrop compared to what awaits the U.S. through 2030. Nevertheless, the **FOMC** has **strong reason** to **bias** its **long-term interest rate forecasts upward**. By significantly overstating the long-term forecast for the fed funds, **Fed policymakers discourage private**and **public-sector borrowers from becoming overly confident regarding** the **longevity** of **historically low benchmark interest rates**.

Exceptionally strong expectations of a very long stay by a low federal funds rate might drive systemic leverage – or the ratio of total U.S. nonfinancial-sector debt to GDP – up to heights that increase the vulnerability of business activity and financial markets to adverse external shocks (such as a pandemic).

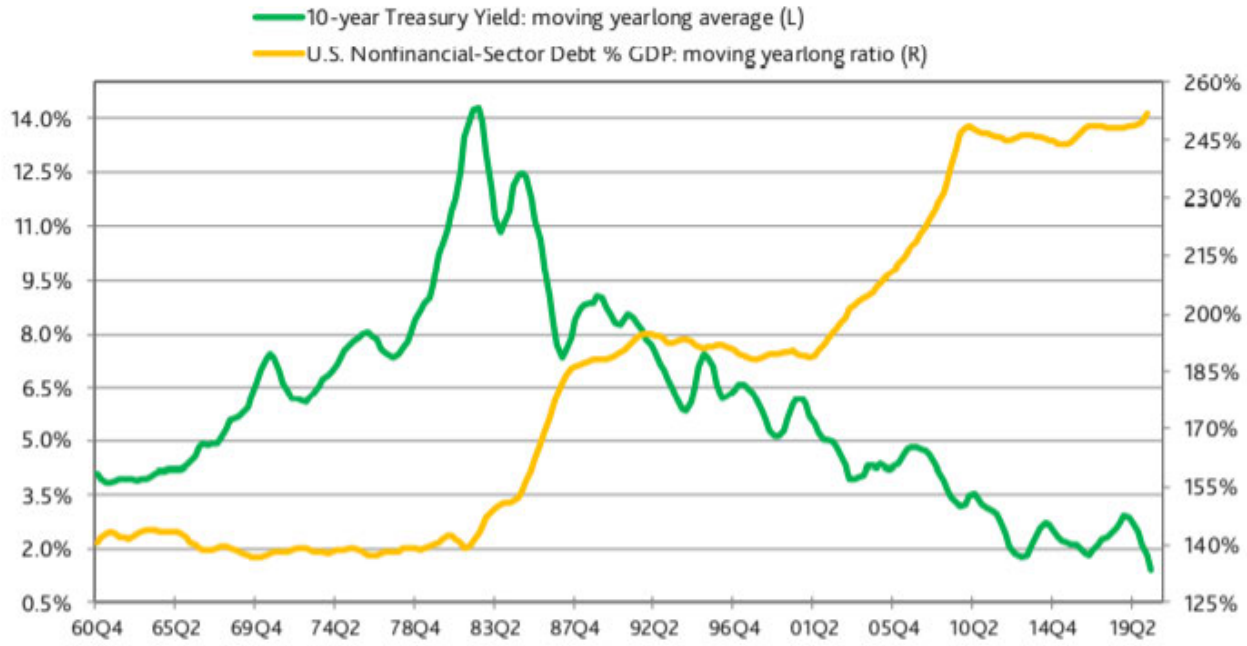
Rate Cuts May Do Less to Spur Spending Amid High Systemic Leverage.

As **systemic leverage increases**, **business activity** might be **expected** to **respond more negatively** to **higher interest rates** and **less positively** to **lower rates.** In other words, **as** the **ratio** of **nonfinancial-sector debt to GDP climbs higher**, **each**

percentage point drop in **Treasury bond yields** will **generate** a **smaller percent increase** in **business activity**, **while each percentage point increase** in **Treasury bond yields prompts** a **deeper percent decline** in **business activity**.

And, thus, we end up with a seemingly paradoxical **inverse relationship between systemic leverage** and the **10-year Treasury yield**. For example, as the ratio of U.S. private and public nonfinancial-sector debt rose from the 192% of the 10 years ended 1999 to the 247% of the 10 years ended 2019, the accompanying average for the 10-year Treasury yield fell from 6.6% to 2.4%, respectively.

Figure 2: Elevated Ratio of U.S. Nonfinancial-Sector Debt to GDP Lends a Downward Bias to Benchmark Interest Rates
sources: Federal Reserve, BEA, Moody's Analytics



It also should be mentioned that real GDP's average annualized rate of growth over a 10-year span slowed from 1999's 3.2% to 2019's 2.3%. In all likelihood, higher leverage was more a way of coping with a downshifting of the underlying pace of economic activity, as opposed to being a primary driving force behind the secular deceleration of economic growth.

Finally, the **U.S. unemployment rate's moving 10-year average rose** from the **5.8%** of the span **ended 1999** to the **6.2%** of the **span ended 2019**. Because of the **labor** force's **slower growth**, the U.S. labor market has held up comparatively given the pronounced secular deceleration of economic growth.

Long-Term Average 2.5% Fed Funds May Require Less Than 3.5% Jobless Rate.

During the 24 months ended February, a 3.73% average for the unemployment rate was accompanied by a 2% average for the federal funds rate. By **implication**, a **long-term average** of at **least 2%** for the **federal funds rate may require** a **long-term average no greater than 4%** for the **unemployment rate**. **Thus**, the **FOMC's median long-term forecast** of **4.1%** for the **unemployment rate seems** to be **inconsistent** with the **FOMC's median long-term projection** of **2.5% for** the **federal funds rate**.

Indications are that the Fed will not allow U.S. Treasury bond yields to rise to levels that might impede the attainment of full employment. If U.S. Treasury bond yields rise by enough to imperil efforts to reach full employment, the Fed will increase its holdings of U.S. Treasury bonds until Treasury yields fall by enough to facilitate a lowering of the unemployment rate. The avoidance of unwanted dollar exchange rate depreciation and the containment of U.S. inflation expectations will allow Fed policy to pursue its full-employment goal.

2nd Quarter's Record-High Net High-Yield Downgrades Mask Apr.-to-Jun. Plunge.

Net high-yield downgrades equal the difference between the number of high-yield downgrades and upgrades. An unofficial tally of U.S. company credit rating revisions showed 29 net high-yield downgrades for the first 23 days of June. A rough estimate suggests that net high-yield downgrades may approximate 50 in June. The second quarter's declining trend for net high-yield downgrades complements the change in the direction of high-yield credit spreads.

In terms of still preliminary estimates, the number of U.S. high-yield net downgrades had previously dropped from April's 216 to May's 90. (Because of an extraordinarily large number of COVID-19-driven downgrades, net downgrades will probably be revised higher.) During 2020's first quarter, U.S. high-yield net downgrades rose from January's -1 to February's very manageable 19 and then soared to March's 176 largely in response to the destructive force of COVID-19.

Net high-yield downgrades were much lower during 2017-2019, or when Bloomberg/Barclays high-yield bond spread averaged 369 basis points compared to June 24's 594 bp. The average number of net high yield downgrades per month were 17 for calendar-year 2019, 1 for 2018, and 2 for 2017. Regarding 2015-2016's profits recession, the average number of net high-yield downgrades per month were 12 for 2015's third quarter, 30 for 2015's fourth quarter, 49 for 2016's first quarter, and 16 for 2016's second quarter. Despite 2015-2016's lower frequency of net high-yield downgrades, Bloomberg/Barclays average 685 bp high-yield bond spread of December 2015 through April 2016 Bloomberg was well above its latest 594 bp. The path taken by the high-yield bond spread during the COVID-19 recession more closely resemble its behavior during 2015-2016's profits recession compared to the broad economic recessions of 2008-2009 and 2001.

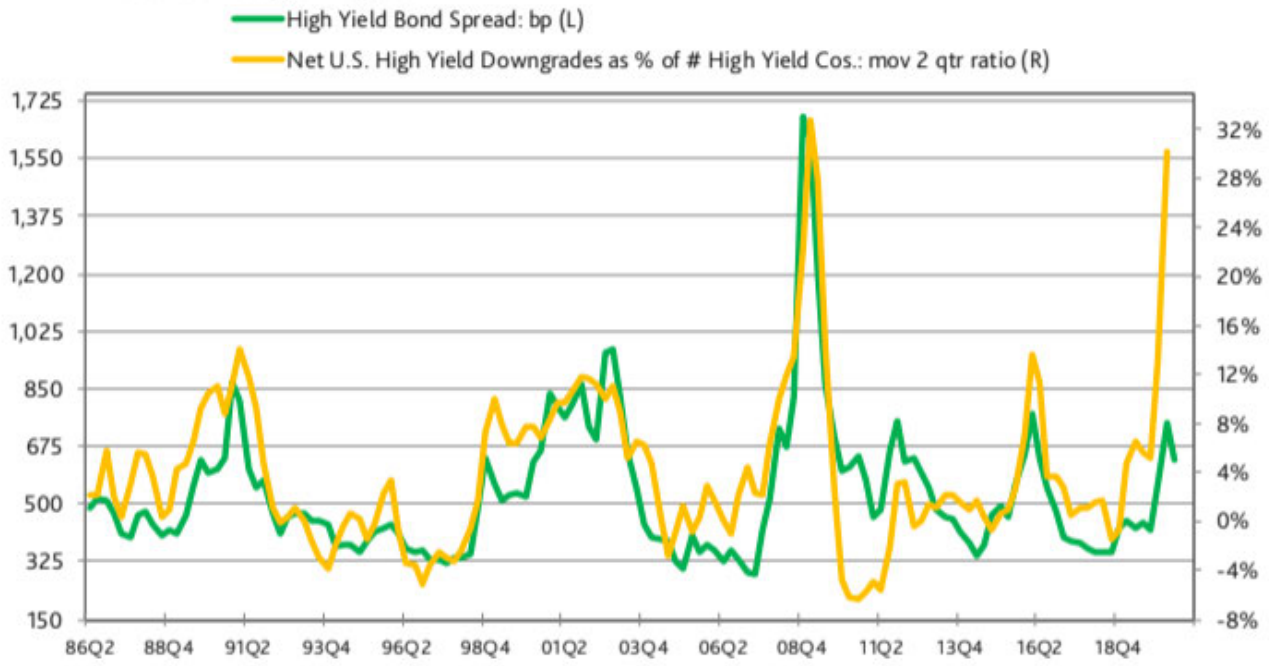
High-Yield Bond Issuance Recession Lasted Just One Month Thus Far.

Moreover, the high-yield bond issuance recession lasted just one month, for now. After plunging by 84% from a year earlier in March (to $6 billion), second-quarter 2020's worldwide offerings of US$- denominated high-yield bonds posted a year-over-year advance of at least 36%, to $147 billion. The latter is very close to 2014's second-quarter record high of $154 billion. By contrast, such high-yield bond issuance incurred a year-over-year plunge of 57% during 2008's Great Recession year. The high-yield bond market has performed remarkably well given the record-high incidence of net highyield downgrades. For 2008-2009's Great Recession, after averaging 10 per month in 2017, the average number of net high-yield downgrades per month jumped up to 42 in 2008 and 37 in 2009. During the Great Recession, the average number of net high-

yield downgrades per month peaked at the 76 of 2009's first quarter. For 2020's second quarter, net high-yield downgrades may average a record high 119 per month.

However, as a percent of the number of U.S. high-yield issuers, the prospective net high-yield downgrades of the two quarters ended June falls short of the 32.9% record high of the two quarters ended March 2009. More specifically, net high-yield downgrades are likely to approximate 30.2% of the number of high-yield issuers during 2020's first half. In view of how a composite high-yield bond spread averaged a record-high 1,678 in 2008's final quarter and 1,604 bp in 2009's first quarter, the spread's 744 bp average of the second quarter to date (never mind the recent 629 bp) seems unsustainably thin.

Figure 3: High-Yield Bond Spread Is Much Narrower Compared to What Is Suggested by Net High-Yield Downgrades
source: Moody's Analytics



However, the high-yield bond market may be assuming a stabilization of net high-yield downgrades, while also recognizing the degree to which high-yield downgrades have been skewed toward high-yield issuers having only loan debt outstanding. Nevertheless, a recent leveraged loan spread of 620 bp was well under its 1,527-bp average of October 2008 through March 2009.

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U.S. Birthrates Fall to Record-Low Level

by Janet Adamy – WSJ – May 20, 2020

American women had babies at **record-low rates last year** and **pushed U.S. births down** to their **smallest total in 35 years**, according to federal figures released Wednesday. About **3.75 million babies** were **born** in **the U.S.** in **2019**, **down 1% from** the **prior year**, provisional figures from the Centers for Disease Control and Prevention's National Center for Health Statistics showed.

The **general fertility rate fell 2% to 58.2 births per 1,000 women aged 15 to 44**, its **lowest level since** the **government began tracking** the figure in **1909**.

The data are the latest sign of how **American childbearing**, which **began declining during** the **2007-09 recession**, **never fully rebounded when** the **economy bounced back**. Millennials have been slower to form families than previous generations, in part, economists say, because they are less financially secure than those before them.

"There are a lot of people out there who would like to have two children, a larger family, and there's something going on out there that makes people feel like they can't do that," said Melanie Brasher, assistant professor of sociology at the University of Rhode Island, who studies fertility.

Birthrates fell or held steady for women of all ages except those in their early 40s. Teen-agers saw the sharpest drop, with a 5% decline in their birthrate. Since peaking in 1991, the teen birthrate has fallen 73%.

The **total fertility rate** – a snapshot of the **average** number of **babies** a **woman** would **have over** her **lifetime** – **ticked down to 1.7 in 2019**, a slight decline from the previous year and **another record low**.

In **almost all years since 1971**, that **rate** has been **below** the **level** of **2.1 needed** for the **population** to **replace itself**, **without accounting for immigration**.

Brady Hamilton, a statistician who co-wrote the new report, said an uptick in births among women in their 40s is a sign that **some births** are just **being delayed**. Women are still having children," he said. "They're just holding off until a later point in time until they establish their education and establish their career."

A leveling-off of births among **Hispanic women**, who **account for** nearly a **quarter** of **U.S. births**, is **also** driving the overall **decline**. They had about **885,900 babies last year**, **down slightly** from **2018**.

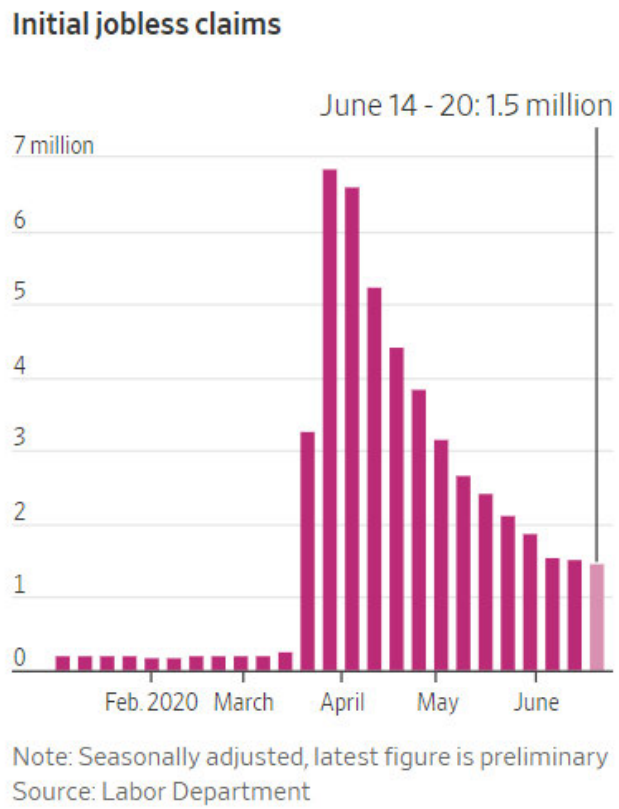
The **economic fallout** from the **coronavirus pandemic** is **expected** to **further depress births** in the **coming years**, experts say. "**People** that were **products** of the **Great Depression**, the **birthrates** were **much lower** for that cohort **than** they were **for people born after World War II**," Prof. Brasher said.

That would **continue** to **pressure** the **age balance** of the **population**, **exacerbating** a **shortage** of **young workers** to **help offset** the **Medicare** and **Social Security costs** of **America's aging baby boomers**.

The NCHS data also showed that the share of babies born preterm last year hit its highest level in more than a decade, with just over 1-in-10 being born before 37 weeks of gestation. The rate of women delivering via caesarean section fell slightly to 31.7%, continuing a decade of general declines in the procedure.

U.S. Initial Jobless Claims Steady at 1.5 Million in Latest Week

by Sarah Chaney – WSJ – Jun. 25, 2020



Job market's slow recovery faces new infections that could impede getting people back to work.

The **number of workers seeking jobless benefits was steady at a historically high 1.5 million** as the job market's slow recovery faced new infections that could impede getting people back to work.

Applications for unemployment benefits have slowly eased from a late March peak of nearly 7 million, but also remain well above pre-pandemic levels. Meanwhile, the **benefits total**, known as **continuing claims**, was **19.5 million** in the **week ended June 13** the **Labor Department** reported Thursday, also stabilizing near a historically high 20 million seen in previous weeks.

While the figures have offered signs the labor market is slowly healing, economists say a recent increase in coronavirus cases could affect efforts to reopen the economy and get people back to work.

"We're seeing a **slowdown in layoffs**, **but hiring hasn't picked up** a tremendous amount," said Nick Bunker, economist at the job site Indeed. "The **recovery** from this is going to potentially be a **very long slog if we can't get** the **virus under control** quickly."

States where the coronavirus is spreading the most are experiencing a slowdown in economic activity, according to Jefferies. Some states, such as Arizona, Texas and Utah, are seeing contractions in activity, Jefferies added.

The claims trend mirrors shifts in other segments of the economy, indicating conditions are improving but have much ground to regain. For instance, retail spending rose sharply last month, but remained well below levels seen before the pandemic upended the U.S. economy.

The Labor Department will publish data on June hiring next week. Employers added to payrolls in May. Still, **overall employment was down** by about **20 million compared with February**.

There's still this two tracks of this ongoing hemorrhaging of jobs while we also see a lot of people getting rehired," said Heidi Shierholz, senior economist at the Economic Policy Institute.

Some policy makers pointed to strong job growth in May as evidence the federal government doesn't need to extend an extra $600 in weekly unemployment benefits, which are slated to expire at the end of next month. That $600, which comes in addition to benefits provided by states, was included in a federal stimulus package to help laid-off workers weather the crisis.

Earlier this week, new findings from the Brookings Institution concluded that states with more-generous unemployment benefits experienced faster recoveries, including greater rehiring and fewer layoffs.

On the other hand, the Congressional Budget Office projected extending the extra $600 in benefits through next January would lead to a decline in employment for the remainder of this year and all of next.

The **government** also **expanded unemployment benefits** to include those who were previously ineligible for such aid, such as self-employed and gig-economy workers. **Two weeks ago**, **761,000 sought benefits through** that **federal program**, which are **tabulated separately from regular state claims**.

US Unemployment Rate to Stay above Pre-Pandemic Levels through 2030 – CBO

by Emmanuel Louis Bacani – S&P Global Market Intelligence – Jul, 2, 2020

The U.S. labor market is expected to improve further as the economy continues with its reopening, but the **unemployment** rate will **remain above pre-coronavirus levels for** a **long time**, **averaging 6.1% through 2030**, the **C**ongressional **B**udget **O**ffice **said** in a new report.

The latest forecasts from the **CBO predict** that the **unemployment rate will peak at more than 14%** in the **third quarter** of **2020 before falling** quickly as output picks up in the second half of the year and throughout 2021.

The unemployment rate is forecast to decline to 7.6% by the fourth quarter of 2021 and to 5.9% and 4.4% in the fourth quarters of 2024 and 2030, respectively. In 2019, the full-year unemployment **rate** was 3.5%.

The **CBO's latest projections** are **based on available economic data as of June 26**. The Department of Labor reported on July 2 that nonfarm payroll employment climbed by a record **4.8 million jobs in June**, marking a **second straight month** of **job gains**. The unemployment rate also dropped to 11.1% from 13.3% in May. A separate report showed that the number of weekly initial jobless claims continued to decline but stayed above 1 million.

In its report, the **CBO also revised** its **U.S. economic output forecast** for **2020**, **saying** that **real GDP** would **only return** to pre**-pandemic levels by** the **middle** of **2022**.

The **nonpartisan budget office now expects** the **U.S. economy to shrink 5.9% this year on** a **fourth-quarter-to-fourth-quarter basis**, a **larger contraction than** the **5.6% decline estimated in May**. The CBO predicts that level of contraction despite also forecasting an annual real GDP growth rate of 12.4% for the second half of 2020.

"Following that initial rapid recovery, the economy continues to expand in CBO's projections, but it does so at a more moderate rate that is similar to the pace of expansion over the past decade," the CBO said, projecting real GDP growth of 4.8% in 2021 and expansions of slightly more than 2% for 2022 through 2030.

The **CBO expects** the recovery of the U.S. labor market and economy to be aided by the **gradual decline of social distancing measures to zero by** the **third quarter** of **2021** and by fiscal and monetary policy actions as they take hold.

U.S. Treasury Yields Rise after Data On Economy

by Sebastian Pellejero – WSJ – Jun. 4, 2020

U.S. Treasury yields climbed to near the top of their recent range after better-than expected data on job losses and the services sector boosted investors' optimism about an economic rebound.

The **yield** on the benchmark **10-year U.S. Treasury note** rose to **0.761%** by market close, its highest level since early April, according to Tradeweb, up from 0.679% at Tuesday's close. The **30-year yield** rose to 1.551%, from **1.478%** Tuesday. **Yields rise when bond prices fall**.

The climb came after a report by the ADP Research Institute showed **private sector employment** in the **U.S. decreased by 2.76 million jobs from April to May**, **beating** analysts' **expectations**. The rise continued after the Institute for Supply Management said its nonmanufacturing index also came in better than expected.

Wednesday's data boosted investors' hopes that the U.S. economy is improving as coronavirus infections fall and restrictions ease. Meanwhile, **investors** are **anticipating added stimulus measures**, with President Trump planning to meet with senior advisers as soon as this week to discuss options for the next relief package.

Some investors said the government's plans to sell more longer-term bonds in coming weeks was also pushing yields higher. In one sign that the increased supply of debt was hitting bonds with longer maturities, the gap between the five-year and 30-year Treasury yield increased to 1.175 percentage points early Wednesday, the widest since February 2017.

Utilities Saw More Volatility than S&P 500

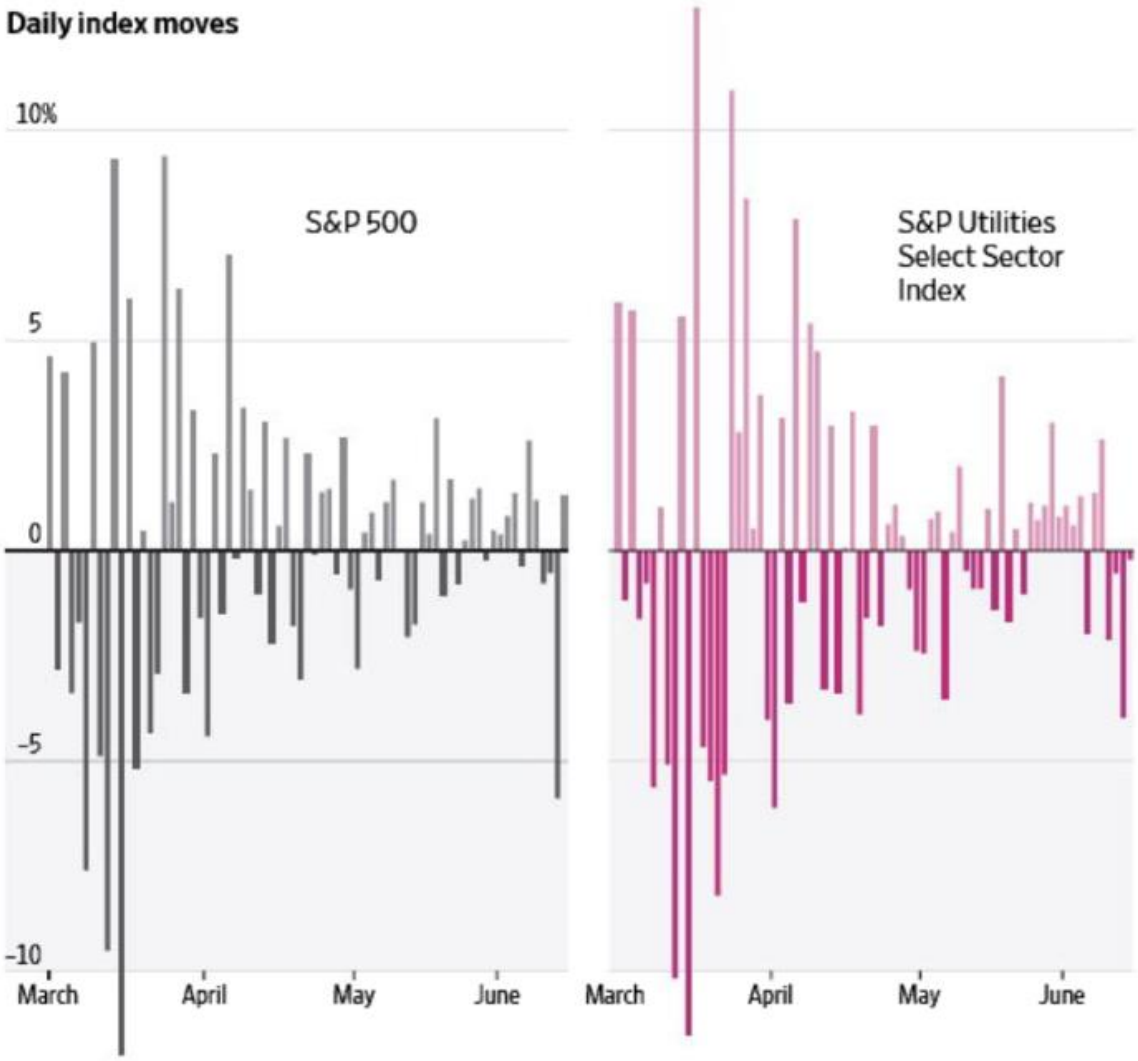
by Anna Hirtenstein – WSJ – Jun. 15, 2020
Pat Minczeski contributed to this article.

Shares have been fluctuating more than the index as investors fret about virus effects.

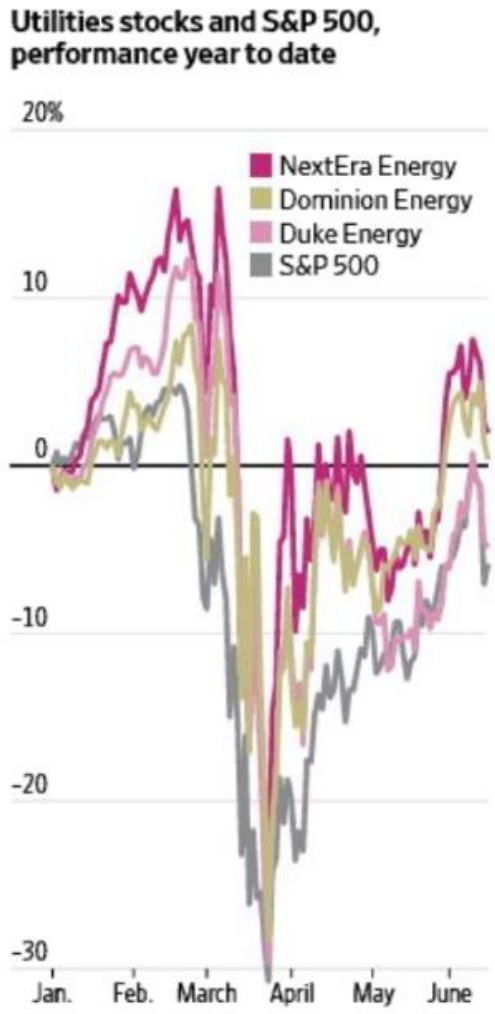
Utilities' stocks have **long** been **seen** as a **safe place** to **park cash** and **collect steady dividends**. **But** as the **coronavirus** spread around the world **this year**, the **shares** have been **more volatile than** the **broader market**.

In **March** and **April**, **shares** of **companies that sell electricity, water and gas posted bigger daily moves than** the **S&P 500 on** a **majority of days**.

The only other time this has happened in the past two years is during a bout of market volatility in February 2018. So far in **June**, it is a **tie**, with **utilities moving more on five days**.



The **utilities sector within** the **S&P 500** is **down** almost **10% this year**, even **as** the **benchmark index rebounded** to **erase most** of its **losses**.



That is because of **concerns** about **falling power demand** and the **increase** in **unemployment following** the **lockdowns** put in place to curb the spread of **Covid-19**, the disease caused by the coronavirus, analysts said.

Millions of people **lost** their **jobs** in recent months, prompting concerns that they **may stop paying** their **bills**.

As dozens of companies cut or suspended their dividends to preserve their cash piles, some investors wondered if the major utilities could be next.

"**Utility investors** are **not used to uncertainty**," said Jeremy Tonet, an equity research analyst at JPMorgan Chase & Co. "There were a lot of concerns with regard to Covid-19 and how much it could impact the space."

Utility stocks are **normally popular** with **pension funds** and **insurers**, who **buy** them **for** their **stability** and **reliable dividend yields**.

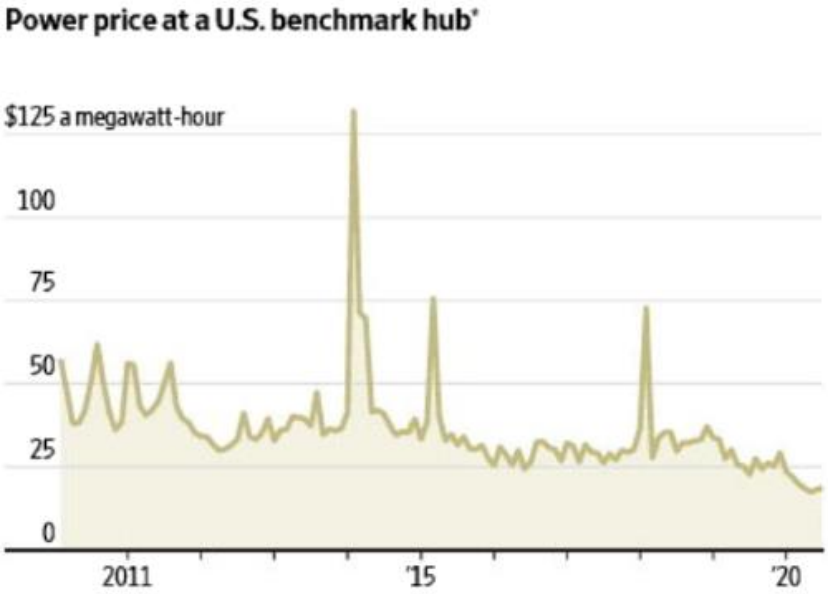
Those expectations came into question during the peak of the market turmoil that ensued in March.

The lockdowns have resulted in a significant **drop in energy use as commercial and industrial activity ground to** a **halt**. A benchmark for wholesale power prices in the US fell 20% in April, compared with the beginning of the year. It is still down nearly 15%, according to data from Bloomberg New Energy Finance.

The **Energy Information Administration** said on June 9 that it **expects electricity consumption** in the **U.S.** to **decline 5.7% in 2020**.

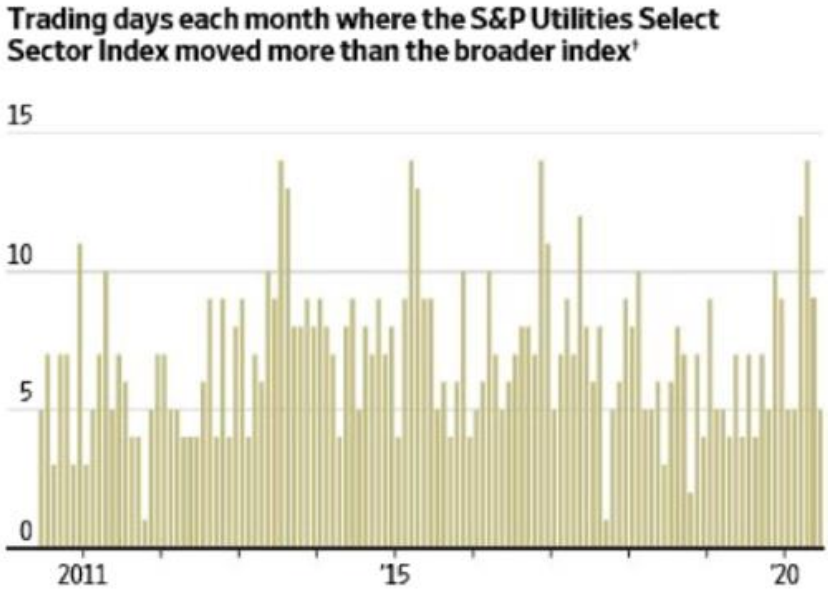
Despite this, nearly all major **U.S. utilities** have **reaffirmed** their **full-year guidance**, according to JPMorgan. One of the few exceptions is Consolidated Edison Inc., which operates primarily in New York, the U.S. city that has been hardest-hit by the coronavirus. Con Ed last month cut its 2020 earnings guidance.

Meanwhile, **CenterPoint** Energy Inc. in Texas has been **one** of the **few utilities** to **trim** its **quarterly dividend** so far.



The regulated nature of the industry means that the revenue holds steady even if power prices fluctuate or sales fall, according to Noah Barrett, head of energy and utilities research at Janus Henderson.

There are **rules** in place in **many states** that **decouple energy demand from** the **companies' cash flows** and fix a rate of return on their investments to ensure that the businesses supplying the population with essential services remain in good health, Mr. Barrett said.



"The dynamic we saw this year with Covid-19 is something that no one knew how to model," given the uncertainty around electricity or natural-gas demand, Mr. Barrett said. "If you look at the stability of the earnings, it hasn't really changed."

The utility companies' very stability may now be working against them, he said.

Some **investors** are **seeking out stocks** that have been **hard-hit** amid the economic downturn caused by the coronavirus lockdowns **and could rebound sharply**, or **sectors** such as **technology** that could **benefit during lockdowns**.

Another reason that utilities' stocks are currently unloved is because of the sharp moves seen in March, said JP-Morgan's Mr. Tonet.

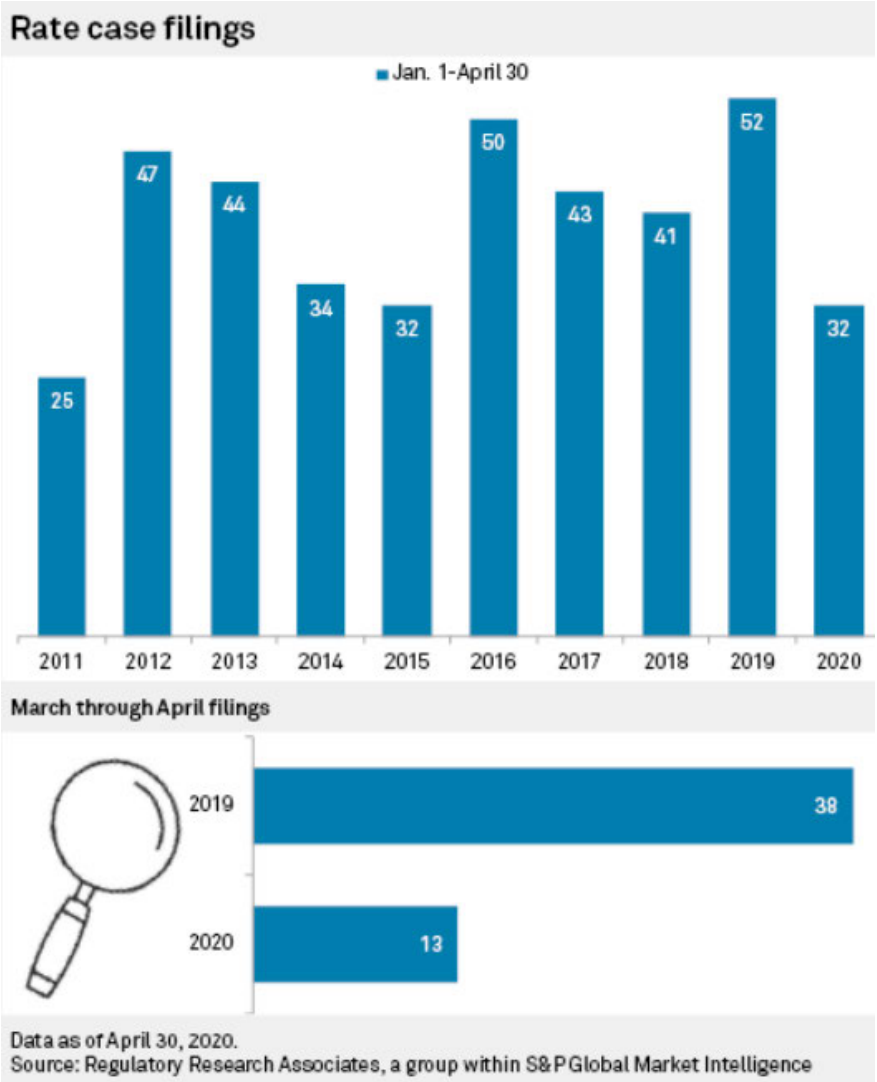
Passively managed funds and **asset managers** that **use algorithmic** or **quantitative strategies may not continue** to **view** these **stocks** as **predictable**, **low-volatility investments**.

But **in** the **long run**, the companies still have **strong fundamentals** and “there’s **room for utilities** to **regain** their **stance as** a **defensive stock**,” he said.

As Case Pullback Becomes Epidemic, Sharp Drop in Rate Change Request Values Seen

by Russel Ernst – Regulatory Research Associates (RRA)
An Affiliate of S&P Global Market Intelligence May 19, 2020

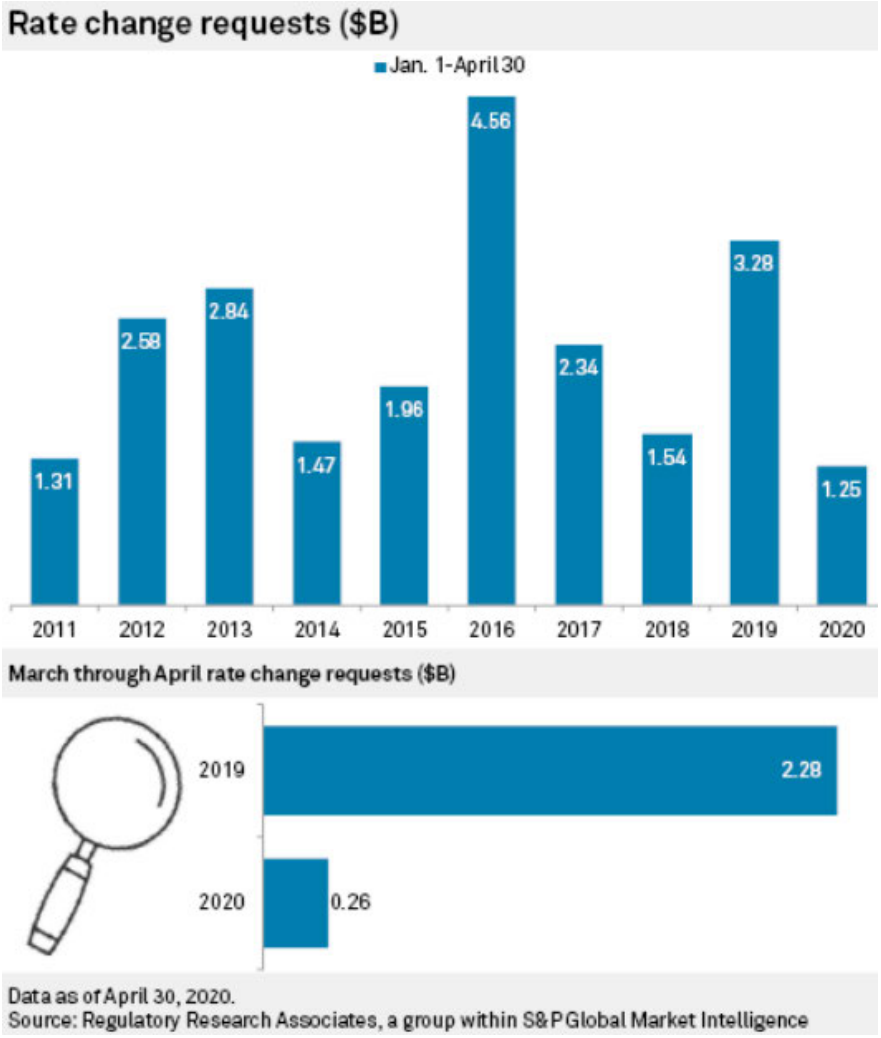
The **impact** that **COVID-19** has had **on** the **number** of **electric and natural gas utility rate case filings has become clear**. But the relative decline in the aggregate value of the rate increase requests submitted in the past couple of months suggests that the manner in which utilities address changes to their cost structures in 2020 is likely to be unique.



Regulatory Research Associates is aware of **13 rate proceedings** that were **initiated** in the **U.S.** during **March and April.** This figure is **significantly lower than** the **38** rate change requests filed during the **comparable period** in **2019**, as shown in the first accompanying image.

As shown in the second image, the **rate change requests** for **March** and **April** of **2020 totaled** about **$260 million**, a **fraction of** the **aggregate $2.28 billion** of **rate adjustments** proposed during the **comparable period** in **2019**. From **Jan. 1 to April 30,** there were **$1.25 billion** of **rate increase filings this year**; this was a little more than **one-third** of the **total sought** in the **corresponding period** a **year ago**.

In **March and April**, **rate proceedings** were **initiated:** by Berkshire Hathaway Energy subsidiary **PacifiCorp** in **Wyoming**, Exelon Corp. subsidiary Delmarva Power & Light Co. in Delaware, Black Hills Corp. subsidiary Black Hills Kansas Gas Utility Co LLC, South Jersey Industries Inc. subsidiary South Jersey Gas Co., CenterPoint Energy Inc. subsidiary CenterPoint Energy Resources Corp. in Arkansas and Oklahoma, **Avista** Corp. in **Oregon**, American Electric Power Co. Inc. subsidiary Appalachian Power Co. in Virginia, Ameren Corp. subsidiary Ameren Illinois Co., Exelon Corp. subsidiary Commonwealth Edison Co., NiSource Inc. subsidiary Columbia Gas of Pennsylvania Inc., and CenterPoint Energy subsidiaries Indiana Gas Co. Inc. and Southern Indiana Gas and Electric Co.



There are currently 82 pending rate proceedings being followed by RRA, the majority of which were initiated in 2019 and in the weeks leading up to the onset of the pandemic. The most active time for rate case filings tends to be in the late spring or early summer, with the least activity seen in the fall. By contrast, the fourth quarter is generally the busiest time of year for rate case decisions, particularly December.

At the **onset** of the **pandemic**, the **main focus** for **regulators** and **policymakers** was **ensuring** that **home-bound**, **newly unemployed ratepayers continued** to **have access** to **essential utility services**. Now that the economic turmoil has taken hold, the focus is **expanding to include consideration** of the **financial well being** of the **utilities** in the face of investor concerns about the longer-term profitability of the sector, including the implications for previously announced capital spending programs and merger activity.

RRA recently noted the apparent reluctance of utilities to file rate cases at a time when many customers are experiencing hardships. Likelihood is that bad-debt costs will rise even in states where the strategy so far is to work out payment plans with customers. **Deferral has emerged** as the **likely path** that **utilities** and their **state regulators** will **choose** to **address** the **impact of COVID-19**. The relative dearth of case filings in recent weeks, coupled with the increasing prevalence of deferrals that will ultimately necessitate rate cases to get the related costs into rates, **suggests** that there could be a considerable **backlog** of **case filings** on tap for the **second half of 2020**.

Deferral requests have gone viral.

Regulatory assets are unique to utilities and are the product of accounting standards. A regulatory asset is created when the utility's regulator authorizes the deferral, to a future period, of a given expense that would normally be recorded on the company's income statement during the present period. Accounting convention dictates that the prospects for future recovery in rates of the cost item in question must be probable for an expense to be deferred. The **deferred costs give rise to** a **regulatory asset** that is **likely, but not guaranteed** to be**, included in rate base** at some point **in** the **future and amortized over** a **number of years**.

Deferrals help to reduce "regulatory lag." It allows the utility to defer recovery of increases in specific costs until the commission can address them at a later date, typically in the company's next rate case. This leaves the **utility's earnings unaffected** by the **increased costs**, as the **increases** are **offset** from an accounting perspective **by** the **creation** of a **regulatory asset** that would **likely** be **recovered through customer rates in** the **future**. **However**, these **deferrals do nothing** to **mitigate any cash flow constraints** that might exist.

State utility commissions have approved the use of deferral techniques for various costs in recent years, perhaps most prominently for costs incurred to restore service after large storms. Few industry participants ever imagined that similar measures might need to be taken to respond to the effects of a pandemic. However, several jurisdictions are examining the merits of using deferral treatment to address changes to utility cost profiles due to COVID-19.

In Missouri, the Missouri Public Service Commission has issued an order opening an investigation into "best practices" the state's utilities could use to address recovery of customer bad-debt expense. The PSC instructed the commission's staff to investigate how the utilities could recover past-due amounts from customers and other "relevant concerns" could be addressed. Notably, Evergy Inc. subsidiaries Evergy Metro, Inc. and Evergy Missouri West Inc. are seeking PSC approval to defer for future recovery "lost revenues" attributable to the pandemic, despite the fact that there is "not substantial commission precedent for the deferral of lost revenues."

In Indiana, a coordinated request for deferral treatment was recently submitted by the large utilities. The companies also propose to track revenue reductions tied to lost sales and "other revenue reductions attributable to ... changes in operations and customer loads" caused by COVID-19.

In Texas, the Texas Public Utility Commission issued orders to create an interim funding mechanism for retail electric providers in the restructured Electric Reliability Council Of Texas Inc. territory, for the lost revenue associated with COVID-19 through a charge on **transmission and distribution utility**, or **TDU**, bills. The orders also allow both the TDUs within ERCOT and vertically integrated utilities outside of ERCOT to establish regulatory assets for the related costs and lost revenues. Also in Texas, the Railroad Commission of Texas authorized gas utilities to record in a regulatory asset account the expenses associated with COVID-19.

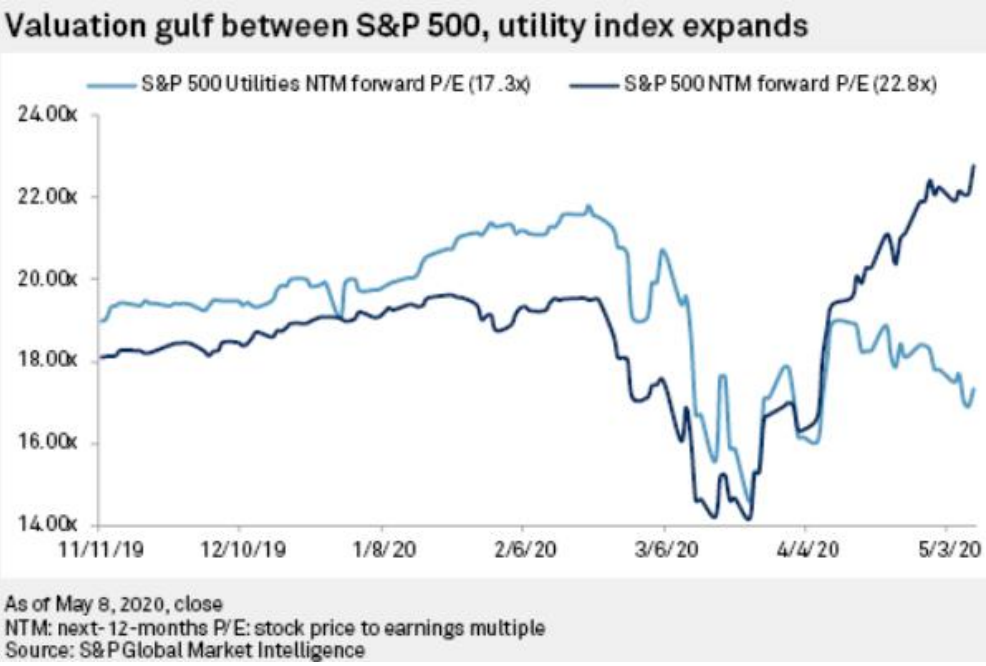
RRA notes that proposals to defer lost revenues are similar to what would occur with a decoupling mechanism. A decoupling mechanism essentially allows the utility to defer fixed costs that it fails to recoup through volumetric charges due to customers' participation in conservation programs, weather fluctuations or altered economic conditions, changes in demographics or even the departure of a large customer. The utility is then allowed to recover the deferrals associated with the unrecovered fixed costs through a mechanism over a period of time, generally with carrying charges on the deferred balance.

Regulators in several other jurisdictions are also looking into the matter, including Connecticut, Delaware, Maryland, Massachusetts, Montana, New York, North Dakota, Pennsylvania, South Dakota and Virginia.

Valuation Delta Between S&P 500, Utilities Reaches Widest Point Since 2003

by Jason Lehman and Charlotte Cox
S&P Global Market Intelligence – May 18, 2020

After tracking closely in **early April** ahead of first quarter earnings season, **valuations on** a **stock price-to-earnings plus growth basis between** the **S&P 500** and **S&P 500 Utilities indexes recently reached** their **widest spread** since **July 2003**, as **utilities endured weeks** of **underperformance while** the **broad market** was **thriving**, **despite** a **souring outlook** for **2020 profits** among **many cyclical sectors surrounding COVID-19 concerns**.



The **S&P 500's next-12-months**, or **NTM, P/E** has **expanded** by more than **15% through May 13 since** our **April** analysis, with the index increasing in value by approximately 1% over that time frame. **By comparison**, the **S&P Utilities' NTM P/E** has **declined** by approximately **10%**, with the index value declining by a similar amount between April 9 and May 13. From an **earnings** perspective, however, **utilities** have shown **relative stability**, registering the fewest financial outlook revisions or withdrawals since the advent of the COVID-19 pandemic versus other S&P 500 sectors: **more than half** of the **companies** in the **S&P 500** have **withdrawn** or **lowered financial guidance over COVID-19**, after 19 more companies in the large-cap index **cut or suspended** their **financial projections** from May 7 to May 13, according to an S&P Global Market Intelligence analysis, primarily within the industrials, consumer discretionary, technology and health care sectors. As of May 8, the S&P 500 Utilities sector was expected to post a 4.1% rise in year-over-year first quarter EPS versus an expected 11.2% decline among the broader S&P 500 index. For additional detail, see the May 14 Financial Focus report US utilities' Q1 earnings results mixed; electric names see highest EPS growth.

The **relative underperformance of utilities since** the **start** of the **pandemic** is perplexing given the group's generally defensive nature and this year's sharp COVID-19 driven stock market and economic declines. A possible explanation is that investors have broadly "written-off" 2020 earnings and are focusing on an anticipated major improvement in 2021 under the assumption that the economy overwhelming re-opens and returns to a much more normal level of production. This scenario would benefit strong growth areas such as information technology, hence the Nasdaq Composite's comparatively strong performance, and the economically cyclical sectors of the economy more than utilities.

Also of note is the wide disparity in valuation between the S&P 500 and S&P 500 Utilities indices for comparisons dating back to the early 2000s. Recall that the utility sector had gone through a massive transformation in the aftermath of widespread industry restructuring, with many companies failing in the 2001-2002 time frame in their with efforts to diversify into non-familiar and high-risk investments both inside and outside the energy sector. Many companies in the utility sector were financially beaten and valuation differentials with the then more-stable broad market sector was financially substantiated. Such substantiation does not appear warranted in the current financial and economic environment.

CenterPoint Energy Inc. and Dominion Energy Inc.'s NTM P/Es remained relatively unchanged versus more pronounced declines within the companies' multi-utility peer group and the electric and gas groups, with both stocks outperforming since April 9. CenterPoint, the worst-performing utility stock in the first quarter amid management turnover, a contentious Texas rate case and a dividend cut to stave off potential cash flow issues, on May 7 announced that it formed a board committee to review and evaluate potential strategic options. The company has also secured a $1.4 billion equity investment that it intends to use together with cash proceeds from asset sales to deleverage its balance sheet to strengthen its credit profile. S&P Global Ratings and Moody's dimmed their credit outlooks on CenterPoint in early April, citing cash flow concerns.

The Dominion Energy shares declined approximately 3% between the April 9 and May 13 period, during which the company affirmed its full-year 2020 operating EPS guidance range of $4.25 to $4.60 and its 5% or more post-2020 annual operating EPS growth rate. The company's Virginia utility also announced plans to add about 5,100 MW of offshore wind, nearly 16,000 MW of solar and about 2,700 MW of energy storage to its portfolio through the end of 2035.

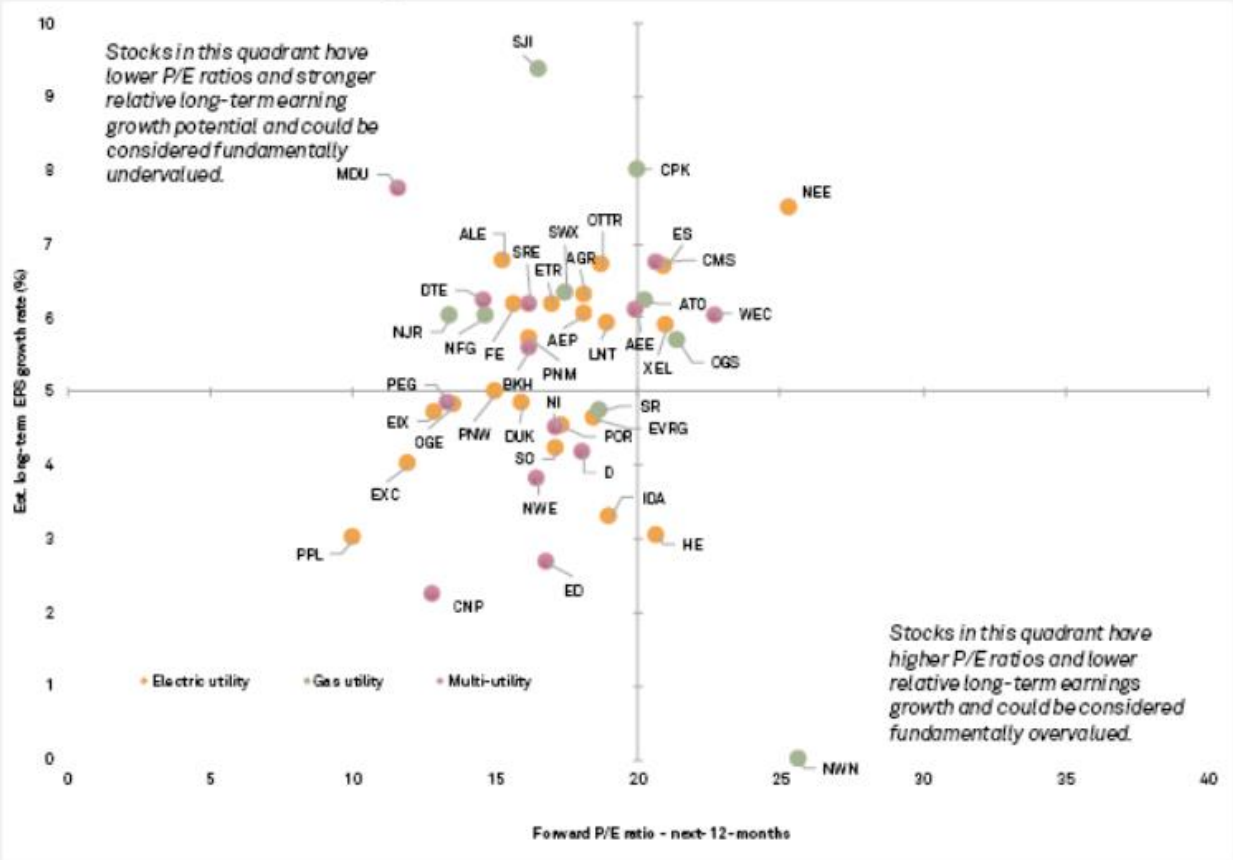
Elsewhere, **electric utility NTM P/Es declined 10.6% on average**, with PNM Resources Inc. declining by 23% and **Portland General Electric** Co. **down 15%**. **Smaller-cap companies** generally have **lower trading liquidity** and therefore, all other things being equal, **tend** to have **more significant share price swings than larger-cap equities**. .

Within the gas utility sector, National Fuel Gas Co. was the sole energy utility to see an uptick it its NTM P/E, with shares rising approximately 4% during a period in which NFG reported fiscal second quarter EPS that surpassed consensus earnings estimates, and announced a $541 million transaction to purchase Appalachian shale

gas assets that are expected to boost EPS and free cash flow. Within the broader gas utility sector, NTM P/Es declined 9% on average, led lower by Southwest Gas Holdings Inc. and ONE Gas Inc.

The quadrant chart below shows how the Regulatory Research Associates' utility universe looks when comparing the P/E ratio and the estimated long-term earnings growth rate. RRA is a group within S&P Global Market Intelligence. Since our most recent valuation analysis April 9, utility NTM P/Es have shifted to the upper left quadrant, likely owing to recent stock underperformance. Large-cap utility NextEra Energy Inc. remains in the upper right quadrant, as well as Eversource Energy and Xcel Energy Inc. Long-term EPS outlooks for the three energy utility sub-groups have held steady since April, suggesting swings in the stock market and changes in individual company circumstances that have impacted stock prices have been the primary driver of NTM P/E valuations in recent weeks.

Valuation quadrant: EPS growth forecast vs. forward P/E ratio



As of May 13, 2020.
For the next-12-months ended Dec. 31, 2020.
Source: S&P Global Market Intelligence

Performance, Earnings Growth

Through May 13, the S&P 500 Utilities lagged with a 15.1% decline versus the S&P 500's 12.7% year-to-date decline, compared with the indices respective 5.8% and 13.7% declines through April 9. From an earnings perspective, the S&P Global Market

Intelligence consensus estimates predict average EPS growth of approximately 4% in 2020 versus 2019's results across all energy utility sectors, when excluding outliers CenterPoint and PG&E Corp. With the broader economic effects of the coronavirus pandemic just beginning in March, most utilities' first-quarter results did not reflect significant pandemic-related impacts – adjusted earnings for the companies in the energy and water utility universe were up 2.9% year over year. Management teams expressed varying levels of uncertainty regarding the remainder of 2020. Despite many companies reporting that commercial and industrial sales fell in April, most management teams affirmed existing earnings guidance ranges. Only a couple of utilities, including American Electric Power Co. Inc., significantly adjusted their planned capital expenditures for the year.

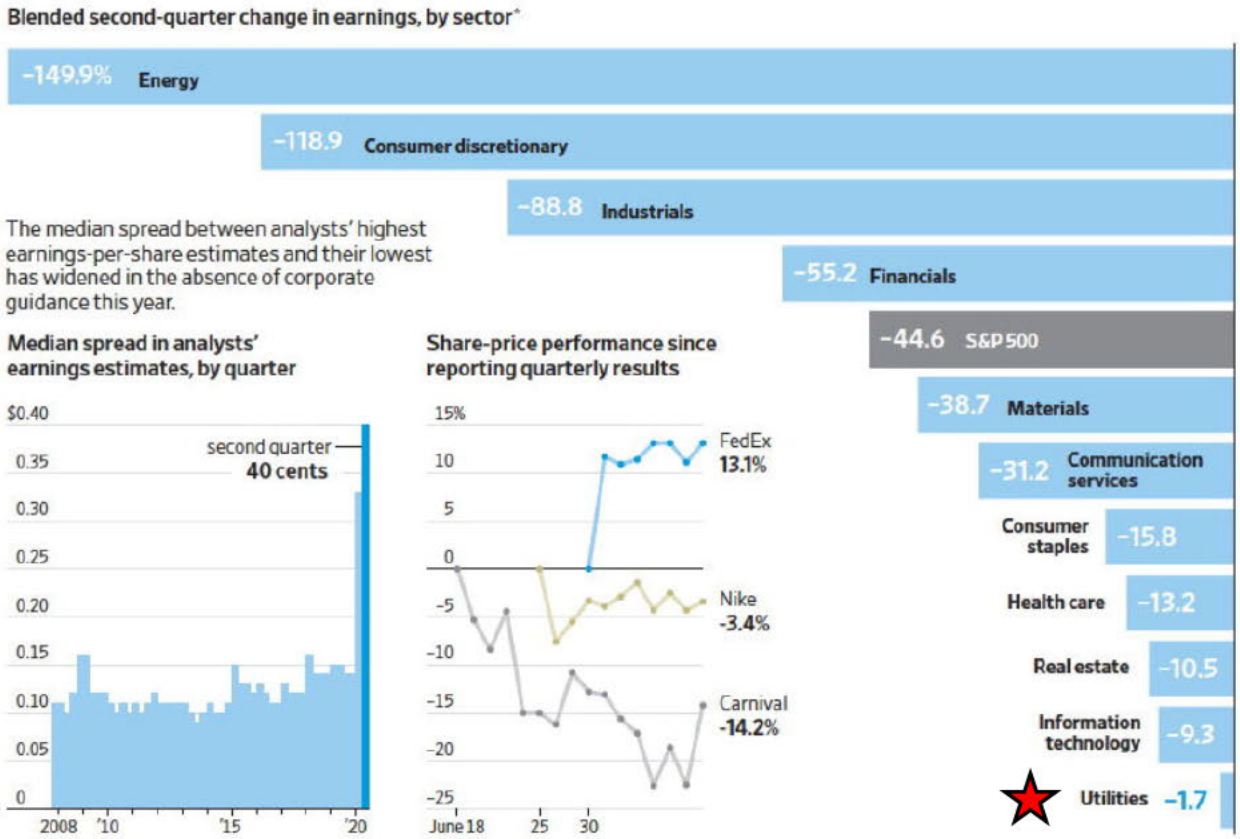
S&P 500, S&P 500 Utilities index performance year-to-date (%)

As of May 8, 2020, close.
Source: S&P Global Market Intelligence

Virus Clouds Outlook for Earnings
Many Companies have Pulled Guidance, Resulting in Wide Gap in Analysts' Estimates

by Michael Wursthorn – WSJ – Jul. 13, 2020

Analysts predict earnings contracted across all 11 S&P 500 sectors in the second quarter, despite a lack of visibility into some companies.



*Includes estimates and reported results for 19 companies through Friday.
Source: FactSet

The coming earnings season poses a big test for **investors and analysts**, who say they are **flying blind like never before**.

More than **180 companies** in the **S&P 500** have **pulled their earnings guidance** in the wake of the economic crisis wrought by the coronavirus pandemic, **limiting** the **visibility of investors**. That has led to the **wide**st **dispersion** in **earnings estimates among analysts** since at least 2007.

Economists generally agree the recently completed second quarter was likely the trough of the downturn, but the extent of the damage is still unclear. JP-Morgan Chase & Co., Goldman Sachs Group Inc. and Netflix Inc. will be among the first companies to open their books, when they unofficially kick off earnings season this week.

"I've either been on the phone with folks in the industry or talking to clients nonstop since March," said Jack Atkins, a managing director who focuses on the freight industry

at Stephens Inc. "Every day, seven days a week, we have been trying to figure out what's going on. I t's been extremely busy and challenging."

The **stock market has remained resilient, despite** the **hazy outlook**. The **S&P 500** has **surged 42% from** its **March low** thanks to **high levels of stimulus from** the **Federal Reserve and Congress**. Although the rally has slowed over the past month, the **index** is **off just 1.4% in 2020**.

Overall, corporate earnings among companies in the S&P 500 are projected to have fallen nearly 45% in the **second quarter from** a **year earlier**, according to analysts polled by Fact-Set. **All 11 sectors** of the index are **expected** to **post declines**, with energy, consumer-discretionary and industrial companies seeing the biggest drops. **Profits** are **expected** to **continue falling** in the **third and fourth quarters**, though at more modest levels, before beginning to climb in the first quarter of next year.

Even before the pandemic, more companies had stopped offering financial guidance. Critics of the practice, including JPMorgan Chief Executive James Dimon and investor Warren Buffett, have argued it promotes a short-term view of corporate success.

Analysts say the guidance is necessary for investors to make knowledgeable decisions and sometimes to keep companies honest. It can also help curb volatility in stocks following the reports.

With limited corporate guidance, **the median spread on analysts' earnings forecasts for companies in the S&P 500 has jumped to 40 cents for the second quarter from 30 cents in the first, according to Dow Jones Market Data. In comparison, the median spread ranged from nine cents to 16 cents over the previous 13 years.**

The wide gap suggests stocks could be in for a wild ride. That has happened increasingly in recent weeks when Wall Street's predictions were wildly off base.

Take FedEx Corp. After suspending its guidance in March, the global shipping company surprised analysts and investors with profit of $2.53 a share when it reported quarterly results on June 30. That topped the average forecast of $1.58 from 22 analysts. Shares of FedEx tore higher after the report, rising nearly 20% over the next two trading days.

Mr. Atkins was among analysts whose estimate fell short. Without any guidance from the company, he leaned on commentary from rival United Parcel Service Inc., which had said in April that its business mix was shifting away from business- to-business and toward consumers, which tends to be more costly and less profitable.

Mr. Atkins revised his model to assume FedEx would take a similar hit. "What we didn't anticipate was the extraordinary level of volume we saw at FedEx in ground [shipping], which helped mitigate some of the makeshift changes," Mr. Atkins said.

The opposite move played out after Nike Inc. reported results on June 25. The sport-apparel retailer posted a loss of 51 cents a share, well outside the range of

analysts who called for a 55-cent profit to a 38-cent loss. Nike shares fell nearly 6% over the following two days.

Analysts aren't just struggling with earnings forecasts. Economic data have also proved difficult to estimate. Unemployment figures for both May and June, for example, came in ahead of expectations, leaving investors and economists scratching their heads.

"We are all in **one way, shape or form operating in uncharted waters**," said Harry Curtis, a managing director at Instinet Inc.

Mr. Curtis covers casinos, lodging and cruise lines, three industries hit particularly hard by the coronavirus crisis. Creating new balance-sheet models has been relatively straightforward for those companies, especially the cruise-line operators, because revenue is basically zero or down sharply from a year earlier, he said.

But analysts are missing those marks as well. Carnival Corp., which suspended its guidance for the year in March, reported on June 18 a loss of $3.30 for the three months ended in May. Predictions from the 14 analysts who cover the stock ranged from earnings of 60 cents a share to a loss of $2.50. Mr. Curtis fell in between those, predicting a loss of $1.97. Carnival shares slid 16% over the two subsequent trading sessions.

At a time like this, Mr. Curtis said, **analysts** better serve their clients by **looking further ahead**. He said he now focuses on whether a company can survive a prolonged downturn and when investors can hope to see some sort of recovery.

"The job has changed," Mr. Curtis said. "**Stock valuations really are now based on earnings power two years out**."

Before the pandemic, the big banks that will be in focus this week rarely offered financial guidance, said Gerard Cassidy, a managing director and head of U.S. bank equity strategy at RBC Capital Markets.

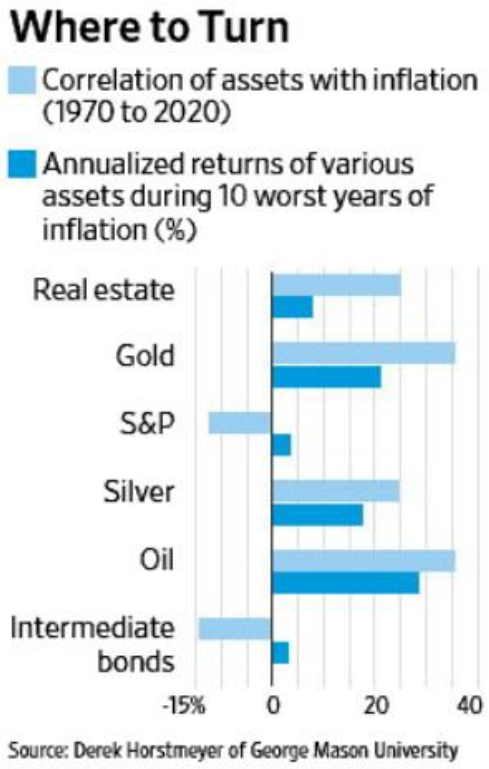
Analysts usually had some insight into their credit losses, a variable in determining bank profits. That has changed, and data suggesting the U.S. economy is recovering faster than expected has muddied the outlook, Mr. Cassidy said.

Which Assets Have Offered Protection against Inflation

by Derek Horstmeyer – WSJ – Jul. 6, 2020

Dr. Horstmeyer is an associate professor of finance at George Mason University's Business School in Fairfax, VA.

The author examined returns **over** the **past 50 years**. **Hard assets like oil correlate** the **most with** the **inflation rate.**



A look at the numbers suggests **stocks** and **bonds have not fared well**.

In **recent months**, **Congress** and the **Federal Reserve** have worked in tandem to **pump** more than **$2 trillion into** the **U.S. economy through** the **Cares Act and Fed liquidity provisions**.

That has some investors starting to worry about a surge of **inflation**, and wondering: **Which investments offer** the **best protection against rising prices**?

The best way to figure that out is to look at the **correlation** between an **asset's returns and** the **rate of inflation**. It's simple: The **more closely** an **asset's returns track** the **course** of **inflation**, the **better** the **asset serves as** a **hedge**. In concrete terms, the **closer** an **asset's correlation coefficient** with **inflation** is **to 1**, the **better protection it offers**. At the other end of the spectrum, a **coefficient between 0** and **minus 1 means the asset's returns tend to move in the opposite direction** of **inflation**.

Hard Assets Pay Off:

Exploring the returns of a variety of **assets over** the **past 50 years** and examining their correlation with the inflation rate over the same period reveals that the assets that **correlate best** with **inflation** are **metals**, **real estate** and **materials** – so-called **hard**, **or tangible, assets**. **Gold** and **oil have** the **highest correlation coefficient**, at **0.35**, with **silver** and **real estate** next **at 0.25**.

While these assets have long been acknowledged as inflation hedges, it is interesting to note that the **best one can do** with such assets over the long term is a **0.35 correlation coefficient**. This means that **only 35%** of the **movement** in the **inflation** rate can be **captured**, **or hedged**, **by gold or oil over many years**. The **rest** of the **long-term movement** in **inflation can't be protected by these assets.**

At the low end of the hedging spectrum are stocks and **bonds**.

Over the **past 50 years**, the **returns** of the **S&P 500** and **intermediate- term bonds** had **correlations** of **minus 0.12** and **minus 0.14, respectively**. This means that **when inflation ticks up**, the **returns of equities and bonds tend to go down**. If you are expecting the stock market or the bond market to protect you against inflation, you may be out of luck.

Proven Results

So, exactly how has this played out in the most extreme inflationary periods? I looked at the average returns of various asset classes in the **10 worst years for inflation in the past half-century** (1970, '73, '74, '75, '77, '78, '79, '80, '81, '90). The **average annual Inflation rate** in those years was **10%**. **Oil delivered an average annual return of 28.4%, gold 20.9%, silver 17.5% and real estate 7.7%.**

The **S& P 500** averaged an **annual return of 3.4%** in those 10 years, and bonds delivered an **average return of 3.1%**.

It **remains to be seen whether** a period of **high inflation lies ahead**, but with **more fiscal stimulus on** the **way** and **no end** in sight **to** the **Fed's bond-buying program**, investors might want to protect themselves against that **possibility** using securities that offer greater than the near-zero yield offered by Treasury inflation-protected securities (TIPS). For those who do, the lesson of the past 50 years is clear: **Hard assets** such as **oil, real estate and metals** seem like far **better bets than securities like equities and bonds**.

White House Won't Issue Economic Projections This Summer, Official Says

by Andrew Restuccia and Kate Davidson – WSJ – Jun. 2, 2020

Projections wouldn't provide a 'meaningful snapshot' of economy because of uncertainty caused by pandemic

The **White House won't issue updated economic projections this summer** because of **uncertainty caused** by the **coronavirus pandemic**, according to a senior administration official.

The official said the coronavirus has resulted in "**fluctuating**" **economic data**, and that White House projections wouldn't provide a "meaningful snapshot" of the economy. The Washington Post first reported the decision.

For decades, U.S. administrations have **issued updated forecasts** for data including **growth**, **employment** and **inflation in** the **summer after issuing** their **budget proposals**, usually in February. The official said the Trump administration didn't issue such projections in 2017 because that year's budget request wasn't released until May, after Mr. Trump took office.

President Trump and other administration officials have **predicted** that the severe slump caused by lockdowns imposed to prevent the spread of the virus would be followed quickly by a **strong rebound** as businesses reopen.

By the fall, "all the signs of economic recovery are going to be raging everywhere," White House economic adviser Kevin Hassett said on CNN's State of the Union on Sunday. The White House hasn't released detailed economic analysis to support its predictions.

The nonpartisan **C**ongressional **B**udget **O**ffice **expects** gross domestic product to shrink 5.6% in the fourth quarter of 2020 from the same period last year. By the **end** of **2021**, the **economy** will still be **smaller than** it was at the **end** of **2019**, and the **jobless rate**—which stood at 14.7% last month—will remain **above 8%,** the CBO projects.

Most economists surveyed by The **W**all **S**treet **J**ournal this month said the economy will likely **bottom out** in May or **June** and that **growth** will **remain below pre-pandemic levels for years**.

"It's going to **take** a **while** for us to **get back**," **Fed**eral Reserve **Chair**man Jerome **Powell said** in a May 17 interview on CBS News's "60 Minutes." The Fed plans to release updated economic projections following its June 9-10 policy meeting, Vice Chairman Richard Clarida said this week.

Wis. Regulator to Lift Utility Shutoff Moratorium July 25

by Kelly Andrejasich – S&P Global Market Intelligence – Jun. 12, 2020

Beginning July 15, utilities in Wisconsin can resume sending out shutoff notices to **customers** who are **behind** on their **electricity** and **natural gas** service **bills** and have **not** yet **made payment arrangements**, state regulators said.

The **Wisconsin P**ublic **S**ervice **C**ommission on June 11 voted to lift a moratorium on utility disconnections for nonpayment put into place in March following Gov. Tony Evers' issuance of a stay-at-home order to prevent the spread of COVID-19. The state Supreme Court struck that order down in May.

A written PSC **order was not yet available** on June 12. But in a news release, the commission said the disconnection moratorium will end July 25 but customers with a **medical condition or infected with COVID-19 can get** a **temporary waiver** from their utility to maintain service.

Commission **Chair**person **Rebecca Cameron Valcq said** as businesses reopen and people return to work, "we **must calibrate consumer protections with costs to all utility customers**. The **longer deferral of payments** are **allowed**, the **more** it will **impact utility bills for everyone**."

But consumer advocates across the country have raised concerns about the continuing inability of many utility customers to pay their bills. While disconnection moratoriums have provided some financial relief, the economic effects of COVID-19 could linger and add to growing past-due amounts. To alleviate that issue, some advocacy groups are calling for more bill assistance while still encouraging customers to pay as much as possible.

The Wisconsin commission, too, is encouraging customers to get in touch with their utilities to arrange payment plans or to sign up for bill assistance. Valcq recommended that utilities offer "extra flexibility" to customers dealing with economic challenges stemming from COVID-19.

According to Regulatory Research Associates, a group within S&P Global Market Intelligence, the commission separately has allowed utilities to defer certain expenditures tied to compliance with the shutoff order, including bad debt or uncollectible expense above what currently is included in rates.

Wisconsin is **not alone** in allowing disconnection moratoriums to end. For instance, the **Iowa** Utilities Board in May said investor-owned utilities in that state could resume disconnections of natural gas, electric and water service on or after **July 1**, according to Regulatory Research Associates.

Along with lifting the shutoff moratorium, the Wisconsin commission also voted to let utilities take up other practices temporarily barred in March.

After **July 15, utilities can again start charging late payment fees** on debts incurred, and they **can refuse service** for **failure** to **provide documentation** to **prove identity** and **residency** beginning July 25. And **starting July 31**, they can require a **cash deposit** as a condition of new service.

WEC Energy Group Inc. subsidiaries Wisconsin Electric Power Co. and Wisconsin Gas LLC, which together do business as WE Energies and Wisconsin Public Service Corp., are evaluating next steps based on the decision, company spokeswoman Alison Trouy said. The utilities are encouraging customers who are having difficulty paying their bills to reach out about options, including payment plans and the potential for financial assistance.

MGE Energy Inc. subsidiary Madison Gas and Electric Co. also is reviewing the PSC's decision to determine what happens next, spokeswoman Kaya Freiman said. Once the utility knows what those steps will be, MGE will make that information available to customers, she said.

Representatives for Alliant Energy Corp. subsidiary Wisconsin Power and Light Co. and Xcel Energy Inc. subsidiary Northern States Power Co. - WI were not immediately available June 12 to discuss the commission's decision. (Wisconsin PSC docket 5-UI-120)

Will Stocks Trail Bonds Over the Next Decade?

by Mark Hulbert – WSJ – Jun. 8, 2020

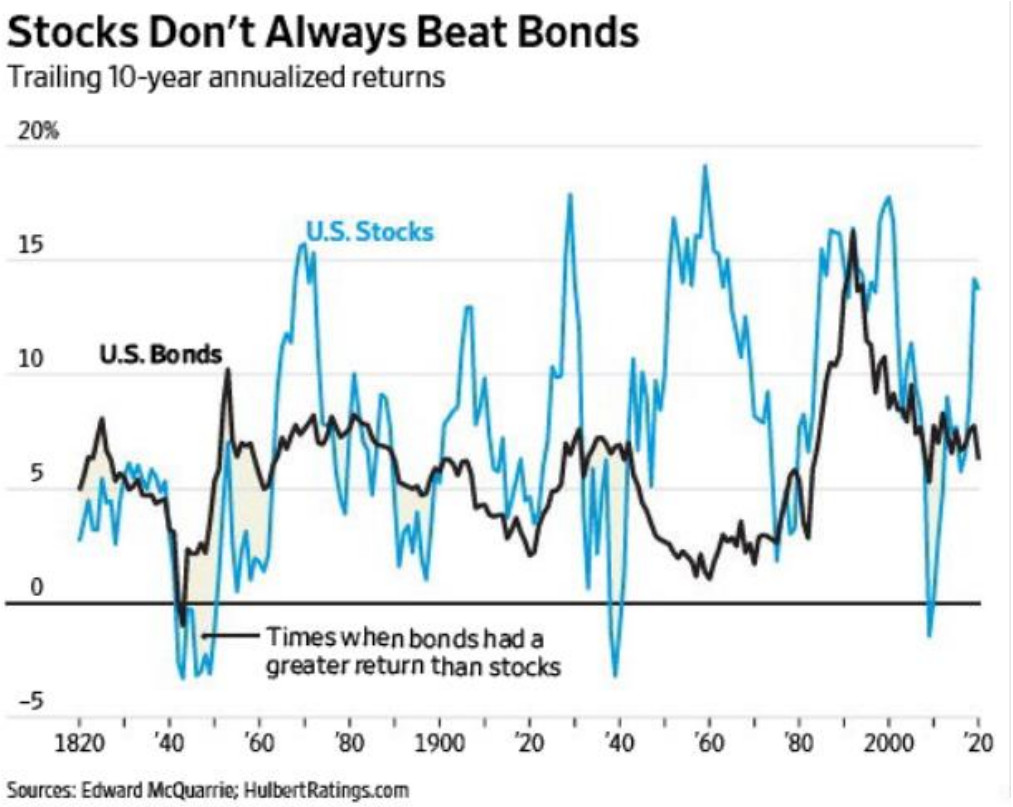
It would startle investors, but a new analysis suggests there is a decent chance that will happen. Conversely, market historian Jeremy Siegel says that stocks will still easily beat bonds in the next decade.

The **conventional wisdom** among investors hasn't changed for years: **Stocks beat bonds in** the **long run**.

This is still a bedrock principle for many, even after the coronavirus lockdowns sent stocks, and the spectacular bull market of recent years, tumbling. Indeed, stocks rebounded with startling speed, launching a new bull market in the process. And

looking ahead, some see little reason to believe that stocks will lose their historic edge over bonds. The bar right now is particularly low: **Currently**, the **Moody's Seasoned Aaa Corporate Bond Yield** is just **2.5%**, and stocks continue to show their resilience. The **S&P 500 yields** almost as much – **1.8%** – and, **unlike bonds**, **equities** have the **potential** to **appreciate** as the economy recovers and corporate earnings rebound.

However, a **prominent dissenting voice** has emerged, and he, too, claims to have history on his side. **Edward McQuarrie**, a **professor** emeritus at the **Leavey School** of **Business** at **Santa Clara University**, has spent years reconstructing the history of stock and bond returns, extending practically to the birth of the country. And he **puts** the **odds** that **U.S. stocks** will **underperform investment-grade bonds over** the **next decade** at a **surprising 4 in 10**.



Most investors will be dismayed by those odds. A decade, after all, ought to be long enough for stocks to assert their historical dominance over bonds, But Prof. **McQuarrie's analysis** is based on close study of **stock** and **bond** returns **going back to 1793**. And he has found that **bonds outperformed stocks** in **38.7% of all 10-year periods since then**. (See accompanying chart.

Prof. McQuarrie furthermore has **found** that, in **many additional 10-year periods**, **bonds lagged behind stocks by less than** an **annualized percentage point**. Investors then presumably felt that stocks didn't offer enough compensation in return for the greater volatility and risk. **If you count all 10-year periods** in which **bonds either beat stocks or trailed by less than an annualized percentage point, bonds held** their **own 51% of** the **time since 1793**.

But wait a minute:

Not all market historians agree with Prof. McQuarrie's calculation of these odds. One is **Jeremy Siegel**, a **finance professor** at the **Wharton School** of the **University of Pennsylvania**. In the most recent edition of his **classic**, "**Stocks for** the **Long Run**," he reports that **bonds beat stocks** in **just 27.9%** of **all 10-year holding periods since 1802**. In an email, Prof. **Siegel** expresses **confidence** that the **next decade** will be one in which **stocks easily beat bonds**.

There are **several reasons** why these **two researchers calculate** the **odds** to be **significantly different**. One is that the **bond market** in the **19th century** was **far less developed**. During **some stretches**, in fact, **no Treasury bonds** even existed.

Prof. **Siegel** reports that he **overcame gaps** in the **historical record** by looking at a **combination** of **yields** on **federal** and **municipal bonds**, an approach that he believes most closely **approximates** what the **risk-free rate** of **return** was in the **19th century**. Prof. **McQuarrie's** approach was to **focus** on **investment-grade bonds** with **long maturities**, **whether federal**, **muni** or **corporate**, since all three were actively traded, and all suffer from gaps in the record. The **consequence** is that Prof. **McQuarrie shows bonds** to have **performed significantly better** in the **19th century than does** Prof. **Siegel**.

The long view:

If Prof. McQuarrie is right about bond-market returns in the 19th century, then we also need to temper our confidence that, so long as we hold on long enough, stocks will come out on top. That is the basis of the nearly universal financial-planning advice that investors with long-term horizons should allocate the bulk of their portfolios to equities.

Prof. **Siegel's data** famously provides support for this belief: **Based** on **all 30-year holding periods since 1802**, the **odds** of **stocks beating bonds** are **more than 91%—compared with 72% for 10-year periods.**

Prof. **McQuarrie's data**, **in contrast**, shows that **stocks' odds** of **beating bonds** are **barely higher** at the **30-year horizon than** at the **10-year horizon**— **65.5% versus 61.3%**.

In an interview, Prof. **McQuarrie** says that his **research** found "**little support** for the **comforting thesis** that the **longer you hold stocks**, the **more likely** you are to **enjoy** a **stronger return than bonds**."

Interest rates and stocks:

Given **today's rock-bottom interest rates**, a long-term bet on stocks over bonds might still make sense. Consider the period beginning in 1940, during which stocks beat bonds by the most they have over any sustained period since 1793. The 10-year Treasury yield in 1940 was below 2%, lower than at any other time in U.S. history except recently. When rates rose, bonds lost value and stocks opened up a big lead.

Wouldn't the same be true for coming years? Prof. **Siegel** thinks so. He says **stocks** will **outperform bonds** over the **next decade** by an **annualized margin** of

between 5 and 6 percentage points – exceeding the average premium over 200 years.

Entering **another dissenting voice**: **Rob Arnott**, chairman of investment firm **Research Affiliates**. One reason for his skepticism, he says, is the **low correlation** between a **given year's bond yield** and the **stock market's subsequent 10-year return**.

To show this, Mr. **Arnott calculates** a statistic known as the **r-squared**, which would be **100% if** a **decade's initial bond yield completely explained stocks' subsequent 10-year return**, and **0%** if that bond yield had **no explanatory power**. **For all 10-year periods since** the **beginning** of the **19th century**, according to Mr. Arnott, the **r-squared** was **just 3%** – "pretty lame," he says.

An indicator with far higher forecasting power for stocks' 10-year returns, he says, is the **cyclically adjusted price/earnings ratio** (or **CAPE**) that was made famous by **Yale finance professor** and **Nobel laureate Robert Shiller**. Mr. **Arnott calculates** that, for **all 10-year periods since 1881**, the first year for which CAPE data is available, the **r-squared** is **over 50%.**

This finding **cancels out** any **argument** that, **based on today's low interest rates**, **stocks will handily beat bonds for** the **next decade**. That's because the **CAPE shows** the **stock market today** to be **more overvalued than in 92%** of the **time** since **1881** – 27.6, versus a long-term average of 17.0.

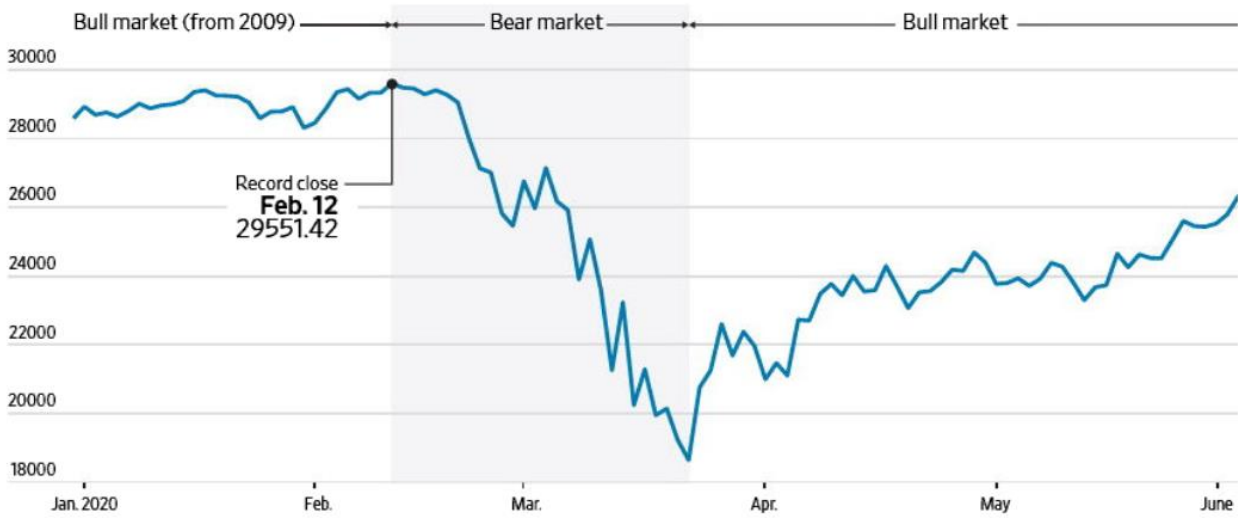
This finding also puts in a different light the **period beginning** in 1940 in which **stocks dramatically beat bonds**. The **CAPE in 1940** was barely **half** where it is **today**, **indicating** a **significantly undervalued market**. It provides a better explanation than low rates for why stocks did so much better than bonds in subsequent years.

Because of this and other considerations, Mr. **Arnott** is **forecasting** that **U.S. stocks will outperform** the **U.S. bond market** by an **annualized margin** of **just 1.3 percentage points over** the **next decade**.

One for the History Books

U.S. stocks this year have startled investors with the lockdowns-triggered slides into a bear market, followed by a sudden return to a bull market (defined as having had a 20%-plus recovery from the low).

Dow Jones Industrial Average



Source: Dow Jones Market Data

Washington Utilities & Transportation Commission

State Regulators Keep Puget Sound Energy Rates Steady

WA UTC Press Release – Jul. 8, 2020

Rate adjustments **ease economic impact during COVID-19 pandemic.**

Seeking to reduce the economic impacts **during** the **COVID-19 pandemic**, the **U**tilities and **T**ransportation **C**ommission used a set of cost-saving measures to **limit increases** in Puget Sound Energy (**PSE**) **rates** to **less than** a **half percent**, while authorizing **additional support** for the **company's most vulnerable customers**.

As a result, PSE's average residential electric customer using 900 kWh a month will see a rate increase of .05% and can expect to pay $0.04 more, for an average monthly bill of $90.14. The average residential natural gas customer using 64 therms a month will see a 0.15% increase and pay $0.09 more for an average monthly bill of $59.69.

PSE originally requested an increase of $139.9 million, or 6.9%, in additional electric revenue and $65.5 million, or 7.9%, in additional natural gas revenue. The **Commission approved** a **total combined revenue increase** of approximately $66 million, **but under** the **Commission's Order** almost **$64 million** of that **won't be reflected on customer bills for at least two years**.

"In the throes of the COVID-19 pandemic, it is not fair either to significantly increase customer rates or to deny the company recovery of the costs it must incur to continue providing safe and reliable service," the Commission said in its order.

The Commission denied PSE's request for an attrition adjustment to address revenue shortfalls of $23.9 million for electric and $11.7 million for natural gas, determining that a **rate adjustment** was **not in** the **public interest at this time**.

Instead, the **Commission authorized PSE** to **recover funds through several methods** including allowing the company to include short-term technological investments that would otherwise be excluded; **deferral** of certain investment costs to be considered in a future rate case; and **adjustments** of **amortization periods** to **ease** the **cost burden on rate payers**.

The **Commission also** focused on **providing additional aid** to **PSE's most vulnerable customers** – who are **disproportionally affected by** the **economic downturn** – by **increasing** the **company's Home Energy Lifeline Program** (**HELP**) funding **by either twice** the amount of the **base rate increase**, or **$1.4 million**, **whichever** is **greater**. HELP provides bill payment assistance to customers experiencing financial hardship.

Additionally, the **Commission ordered PSE** to **work with their Low-Income Advisory Group** to **develop** a **disconnection reduction plan within one year** and

file a **detailed annual report** to **better monitor** and **analyze customer disconnect trends**.

Finally, PSE must speed up the return of $51.7 million in federal tax savings resulting from the decrease to corporate income tax rates in the 2017 Tax Cut and Jobs Act. PSE will now need to pass back these savings to customers in three years instead of four as originally proposed by the company.

The **Commission** also **accepted PSE's proposal** to **adjust** the **annual depreciation expense** of **Colstrip Units 3 and 4**, a coal-fired power plant in Montana. A portion of the expense includes decommissioning and remediation costs, to **ensure** those plants are **fully depreciated by 2025**, as required by the **Clean Energy Transformation Act** (**CETA**).

The **Commission** has **received 720 public comments** to date on Puget Sound Energy's rate proposal – **712 opposed**, **three in favor**, and five undecided.

The new rates will become effective July 20.

Bellevue-based PSE provides electricity service to more than 1.1 million electric customers in eight Washington counties: Island, King, Kitsap, Kittitas, Pierce, Skagit, Thurston, and Whatcom. They also provide natural gas service to more than 800,000 customers in six Washington counties: King, Kittitas, Lewis, Pierce, Snohomish, and Thurston.

The UTC is the state agency that regulates private, investor-owned electric and natural gas utilities in Washington. It is the commission's responsibility to ensure regulated companies provide safe and reliable service to customers at reasonable rates, while allowing them the opportunity to earn a fair profit.

Xcel Energy's Minnesota Utility Issuing $700M of Green Bonds

by Nephele Kirong – S&P Global Market Intelligence – Jun. 9, 2020

Northern States Power Co. – Minnesota priced **$700 million** of its **2.60% first mortgage bonds due** Feb. 15, **2050**.

Interest on the bonds is payable semiannually on June 1 and Dec. 1, beginning Dec. 1, 2020.

The bonds have a **spread** to **benchmark Treasury** of **105 basis points** and were expected to be **rated Aa3** by **Moody's**, **A** by **S&P** Global Ratings and A+ by Fitch Ratings.

The **Xcel Energy** Inc. **subsidiary** plans to **use proceeds** for **eligible green expenditures**, particularly the development and operation of **transmission infrastructure** to **support** its **wind energy projects**, for the June 30, 2019 to Dec. 31, 2020 period.

Pending such use, the company may temporarily invest net proceeds in interest bearing obligations, including investments in a utility money pool.

Morgan Stanley & Co. LLC, **MUFG** Securities Americas Inc., **U.S. Bancorp** Investments Inc., **Wells Fargo** Securities LLC, **BofA** Securities Inc. and **Mizuho Securities** USA LLC served as **joint book-running managers**. **BMO Capital Markets** Corp. and **BNY Mellon Capital Markets** LLC acted as **senior co-managers**, while Fifth **Third Securities** Inc. and **Loop Capital Markets** LLC were **co-managers**.

Xcel Energy's Wis. Utility Sells $100M of 1st Mortgage Bonds

by Nephele Kirong – May 19, 2020

Northern States Power Co. - Wisconsin **sold $100 million** of **its 3.05% First Mortgage Bonds**, series **due** May 1, **2051**.

Interest on the bonds is payable semiannually May 1 and Nov. 1, beginning Nov. 1, according to a May 18 prospectus.

The bonds have a **spread to** benchmark **Treasury** of **170 basis points** and were expected to be rated **Aa3** by **Moody's**, **A** by **S&P** Global Ratings and A+ by Fitch Ratings.

The Xcel Energy Inc. subsidiary plans to use a portion of the net proceeds to **repay** outstanding **commercial paper** and the rest for general corporate purposes. Pending such use, the company may temporarily invest net proceeds in interest-bearing obligations.

As of March 31, Northern States Power - Wisconsin had approximately $76 million of commercial paper outstanding with a weighted-average interest rate of about 2.52%.

Mizuho Securities USA LLC served as **sole book-running manager** for the offering.

Tech and Utilities Stocks Both Rally in Polarized Market - Two best-performing sectors in S&P 500 in 2020 typically move in opposite directions

by Akane Otani – Feb. 21, 2020

Faith that big tech companies like Apple are resilient enough to withstand a temporary slowdown in global growth has helped keep shares higher.

Risky investments have rallied this year. **So have safe ones**.

The tug of war across financial markets shows just how divided the outlook among investors is as they struggle to assess the economic toll of the growing coronavirus epidemic.

Within the stock market, **the two best-performing sectors in the S&P 500 in 2020 have been technology and utilities**. That is notable because the two groups often move in opposite directions—with technology stocks rallying when investors feel confident in taking on riskier investments, and **utilities and other safety stocks typically doing their best when money managers feel most skittish about economic prospects.**

The S&P 500 tech sector is up 8.2% for the year, **while utilities have risen 8.3%.** Both groups have significantly outperformed the broader index, which has climbed 3.3% in 2020.

"It's a really polarized market," said Art Hogan, chief market strategist at National Holdings. Even as the S&P 500 hangs within a few percentage points of its all-time high, "we have all of this money plowing into harbors of safety," he said.

Money managers and analysts had begun the year relatively optimistic about the global economy. Risky assets like stocks had even been relatively resilient through some spurts of selling related to the coronavirus epidemic, with analysts attributing the calm to investors' faith that

the disease would be contained and that central banks would deploy enough stimulus to help offset a temporary pullback in growth.

But in recent days, that confidence has shown signs of faltering—with defensive parts of the stock market, as well as the price of other havens like gold and U.S. Treasurys racing higher. The yield on the 30-year U.S. Treasury slipped to a record low Friday. Yields fall as bond prices rise. Gold, meanwhile, jumped 1.7%, ending at its highest level since February 2013.

Analysts have attributed the moves to growing fears that the coronavirus epidemic will disrupt consumer spending, manufacturing and supply chains around the world more than investors had first expected. Many firms' initial estimates of the epidemic's impact on growth had assumed that the disease would be contained within the first couple months of the year. But in recent weeks, reports have shown the number of cases continuing to jump around the world, and multinationals like Apple Inc. have warned that their sales would take a hit because of a pullback in consumer spending.

With that kind of dim outlook, investors might typically retreat from risky assets overall. But faith that U.S. multinationals—particularly big tech companies—are resilient enough to withstand a temporary slowdown in global growth has helped keep those shares higher.

Even with Friday's pullback, Netflix Inc. is up 17% for the year. Alphabet Inc. has risen 11%, while Microsoft Corp. is up 13%.

It is difficult to imagine the disconnect being sustainable for long, Mr. Hogan said.

"Are we really pricing in recession fears? Or are people just so nervous they'll pay for anything with yield?" he said.

Power Play

by Joshua Funk and J. Paschke – AP, Oregonian – Jul. 17, 2020

Investor Warren Buffet found a use for some of **Berkshire Hathaway's** massive pile of cash with **$4 billion acquisition** of **Dominion Energy's natural Gas Pipeline** and **storage businesses**.

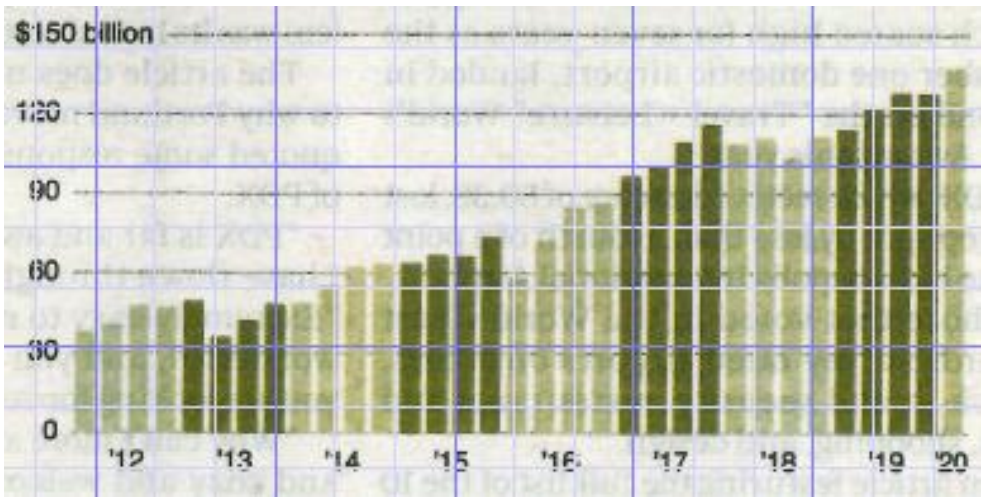
The deal for more than **7,700 miles** of **natural gas pipelines** is Buffett's biggest since 2016, when he bought Precision Castparts for $32.7 billion. But it may not quiet critics who complain he hasn't done more to put a substantial dent in **Berkshire's $127 billion of cash** and short-term investments.

The famed 89-year-old investor said he is taking a cautious approach during the current crisis because he wants to be prepared for whatever economic fallout comes, and he continues look for deals at attractive prices.

"There's been a lot of criticism about when he is going to come alive again. And I think he's just very, very patient waiting for the right time," said Andy Kilpatrick, a retired stockbroker who wrote a Buffett biography.

And the **amount of cash Berkshire is holding** is **likely** to **continue** **growing** **steadily** because the **company's** **businesses** and **investments** **generate** **roughly** **$1.8 billion a month**.

Quarterly Berkshire Hathaway Cash and Short-Term U.S. Treasury Bonds



Source: Company's Filings

Rate for 30-Year Mortgage Falls to Lowest on Record

by O Rla McCaffrey – WSJ – Jul. 17 2020

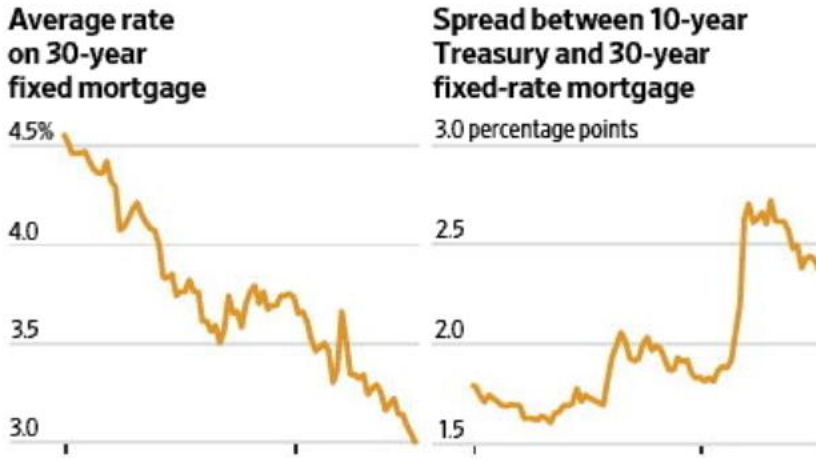
In a year of financial firsts, this one stands out: **Mortgage rates have fallen below the 3% mark**.

The **average rate** on a **30-year fixed mortgage fell to 2.98%,** mortgage-finance giant Freddie Mac said Thursday, its **lowest level in** almost **50 years of record-keeping**. It is the **third consecutive week** and the **seventh time this year** that **rates** on America's most popular home loan have **hit** a **fresh low**.

The coronavirus pandemic has upended markets around the world, sending stocks on a wild ride and yields on U.S. government debt to record lows, but its effect on the 30year mortgage is especially significant. In the **early 1980s**, it **peaked above 18% after** the **Federal Reserve raised rates to fight runaway inflation**.

Below 3% is a "tremendous benchmark," said Jeff Tucker, an economist at Zillow Group Inc. "It's also an indication that we remain in a crisis here."

The average rate on the 30-year mortgage stood at **3.72%** at the **beginning** of the **year and 3.81%** a **year ago**, according to Freddie Mac. **Mortgage rates tend** to **move** in the **same direction** as the **yield** on the **10-year Treasury note**. **Yields fall as prices rise when nervous investors buy up safe-haven assets like bonds when** the **economic forecast** is **darkening**.



The spread between the yield on the 10-year Treasury and rate on the 30-year mortgage has narrowed in recent weeks, largely because lenders had capacity to process applications after clearing a backlog of re-financings. Still, the larger-than usual gap means there is room for rates to fall even farther, Mr. Tucker said.

Not all mortgage rates have declined at the same pace. Interest rates on jumbo home loans, those too large to sell to Freddie Mac or Fannie Mae, have fallen to around 3.77% from 3.84% at the beginning of the year. From the middle of 2015 to this March, jumbo rates were consistently lower than or equal to the rates on so-called conforming loans, according to Bankrate.com.

Earlier this year, some lenders placed new restrictions on these larger loans – in most markets, more than $510,400 – after the investors who typically buy them soured on loans without government backing.

Low mortgage rates typically boost home sales, but they did little to ease the pandemic's impact on the housing market this spring. Existing-home sales fell 9.7% in

May from the month prior and 17.8% in April, according to the National Association of Realtors.

Low mortgage rates typically boost home sales, but did little to ease the pandemic's impact this spring. Rates look great," said Tendayi Kapfidze, chief economist at LendingTree. "But when you get into the details there are other factors affecting whether people are able to purchase homes."

A home purchase is out of the question for many of the millions of Americans who have lost their jobs in recent months. And fears that recurrent coronavirus outbreaks will lead to a protracted downturn could also keep some with the means to buy from committing to big purchases.

Sydney Countie had to shelve her home buying plans in the spring when she was furloughed from her job as a social-media coordinator and her boyfriend was forced to close the tattoo studio he owns.

Ms. Countie returned to work within two months, but the lockdown kept the tattoo studio closed until late June. The four mortgage lenders they talked to wouldn't approve a loan for a one-income couple, she said. They decided to keep renting and try their luck in the housing market next spring.

For those who are looking to buy, inventory is tight and prices are high. The number of homes on the market fell 27.4% in June from a year earlier, according to Realtor.com. Home prices rose 4.7% year-over-year in April, potentially muting any savings from low rates.

Still, there are indications that some of the buyers who stayed home during the spring are venturing into the market. Mortgage purchase applications rose about 17% in June from a year earlier, according to data from the Mortgage Bankers Association. Economists at Fannie Mae expect sales to peak in July or August as the backlog of delayed spring deals is cleared.

Falling rates often prompt home buyers to speed up their purchasing plans. That was the case for Phillip Caldwell and his wife, Tracey, when they locked down a rate of 3% in late May, much lower than they expected.

The first-time home buyers decided to move from Seattle to Mr. Caldwell's hometown of St. Louis. "A big factor that played in was that mortgage rates were going down," Mr. Caldwell said. "We thought it might behoove us to get it done now."

Bond Yields Fall As Jobless Claims Top Expectations

by Sebastian Pellejero

U.S. Treasury yields fell after data showed the **number** of **Americans** who **filed** for **unemployment benefits last week** was **higher than** economists **expected**.

The **yield** on the benchmark **10-year Treasury note fell** to **0.611%,** according to Tradeweb, from 0.629% on Wednesday. The **30-year bond yield** followed a similar path, finishing the trading day at **1.302%** from 1.330% Wednesday. **Bond yields fall when prices rise**.

Yields declined after **Labor Department** data showed the **number** of **Americans filing for jobless benefits held nearly steady last week** at **1.3 million**, higher than the 1.25 million figure economists had anticipated. While new jobless claims have eased from their peak in late March, 17.3 million Americans continue to receive unemployment benefits, as companies remain cautious about hiring.

Meanwhile, new data from the Commerce Department showed **U.S. retail sales increased 7.5% in June**, driven by a **pickup** in **sales** at **motor-vehicle** dealers, **furniture**, **clothing** and **electronic** stores. Retail spending totaled $524.3 billion last month, up from $487.7 billion in May and nearly back to pre-pandemic levels.

Ultralow long-term yields indicate investors expect short-term interest rates to **remain near zero** for an **extended period**. Analysts said investors continue to buy Treasurys out of fear that the U.S. economy could take a long time to recover. **Investors** are **also confident** that the **Federal Reserve will continue** to **support** the **economy by buying Treasurys** and **keeping short- term rates low**.

Some analysts said investors are more likely to buy Treasurys now that the yield on the **10-year note is trading within** a **relatively narrow range**, after rising to near 1% in early June.

"As the 10-year yield stays firm between 0.6% and 0.7%, investors are less fearful of buying Treasurys," said Jim Vogel, interest-rate strategist at FHN Financial. "Investors are putting money to work on a more disciplined basis now that a lot of their immediate concerns are taken care of."

Investors are becoming more **concerned** that any **further recovery** in the **U.S**. **could be stymied** by the **recent surge** in **coronavirus infections**.

While last month's bounce-back in consumer spending was encouraging, the data are "offset by the disturbing resurgence in infections across the South and West, which threatens to send nervous shoppers back to their homes in coming months amid **still-high joblessness**," said BMO Capital Markets analysts in a note.

S&P Global
Market Intelligence

June 15, 2020
spglobal.com/marketintelligence

RRA Regulatory Focus

The rate case process: a conduit to enlightenment

Russell Ernst, CFA
Principal Analyst

Monica Hlinka
Associate Research Analyst

Sales & subscriptions
Sales_NorthAm@spglobal.com

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The utility sector is unlike any other sector of the economy. In a competitive industry, customers have numerous purchasing options. In the automotive or consumer products industry, customers can select from the product offerings of many different providers, and product quality and price have considerable influence on consumer purchasing decisions. If a seller's prices are too high or the quality of the product does not meet the customer's standards, the customer can select the wares offered by another seller. Prices in competitive industries are set by supply and demand in the marketplace.

Utilities, on the other hand, cannot simply set up shop wherever they choose. Utilities are natural monopolies because their capital costs are enormous. Monopolies, by definition, also have high barriers to entry. However, a company with monopoly power cannot be allowed to operate without oversight, otherwise the price of the company's product could be exorbitant. Hence, the state utility commissions were created to regulate the rates charged by the utilities and, together with the utilities themselves, investors and customers, comprise what is known as the "regulatory compact."

The regulatory compact is an agreement that is unique to the utility space and calls for the utility to provide safe, reliable and reasonably priced service, the commission to provide the utility with a reasonable opportunity to recover its costs and earn a return similar to that of other investments with similar risk characteristics, the customer to pay the approved rates and the investor to supply the capital necessary to maintain or expand the utility system.

The rate setting process is grounded in the fact that utilities operate as monopolies where, in the absence of regulation, there is no market for competitive pricing of the utility's product. This applies to utilities in non-restructured jurisdictions, whereas in restructured jurisdictions the power commodity itself can be considered competitively priced given the presence of competition for generation supply.

Regulatory compact

Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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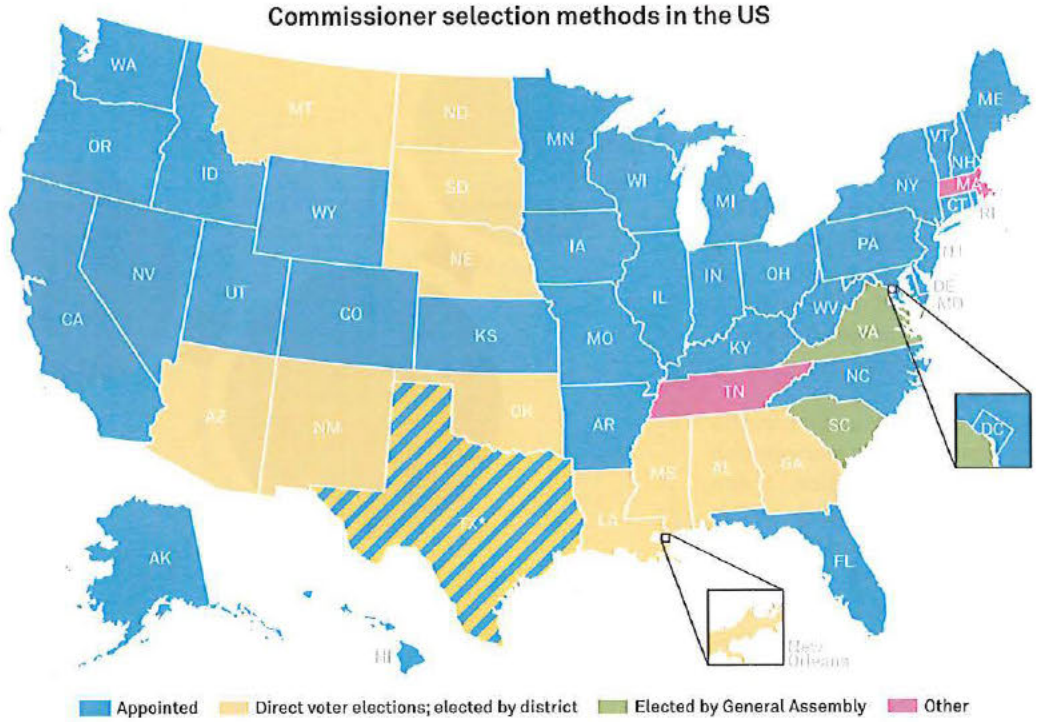
In these jurisdictions, the price of generation for "standard offer" customers — those who have not selected an alternative supplier — is generally set through an auction, a request-for-proposals process or through bilateral contracts between the competitive power suppliers and a separate state agency or the incumbent utility. In each of these jurisdictions, the resulting competitively determined price is passed on to the consumer, and the utility is simply a regulated deliverer of the power. Similar issues exist in the natural gas industry, where many customers have a choice of gas commodity suppliers; however, the distribution function continues to be the responsibility of the utility.

Since there is no market-based approach to setting utility rates, with the exception of the limited cases mentioned above, a cost-of-service methodology is used, whereby the commission examines the utility's costs and capital investments, determines whether they were prudently incurred, and then adds a risk-adjusted return for the utility's shareholders to the prudent costs to be recovered. This figure, known in industry parlance as the "revenue requirement," is then translated, in most instances, into a combination of a fixed monthly charge and an additional usage-based charge, per kilowatt-hour for an electric utility or per therm for a gas utility, which are used to determine each customer's total monthly bill.

The commissioners

Utility commissions in the U.S. have between three and seven members. In most jurisdictions, commissionerships are appointed positions, and these appointments are typically made by the chief executive of the jurisdiction. However, in 15 jurisdictions, utility commissioners are elected. Commissioners have considerable influence over utility policies and rate case outcomes, and some jurisdictions are more politicized than others. For an overview of the selection process at the state and federal utility regulatory agencies followed by Regulatory Research Associates, a group within S&P Global Market Intelligence, refer to the 1/14/20 Topical Special Report entitled "The Commissions." For detailed information on the composition of each commission and its unique policies, refer to RRA's Commission Profile pages.

Commissioner selection methods in the US



Data as of May 15, 2020.
* The Public Utility Commission of Texas members are appointed by the governor, while members of the Railroad Commission of Texas are elected in statewide elections
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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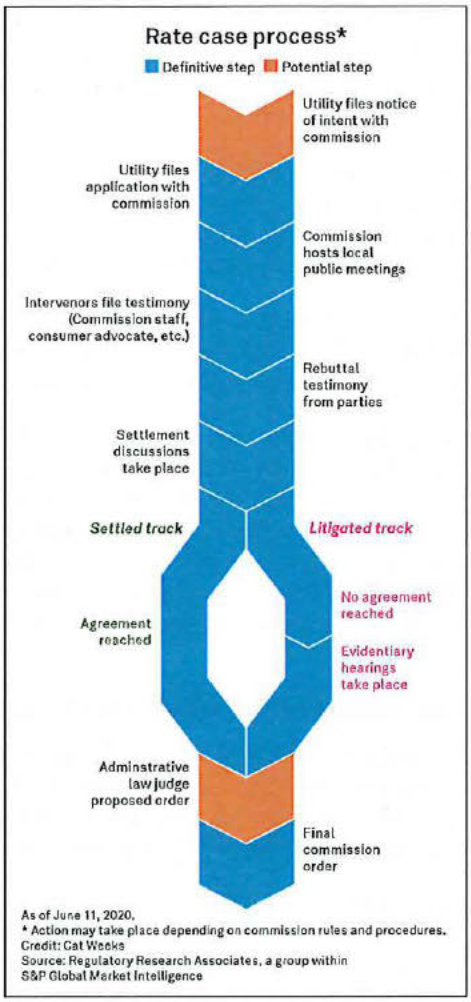
The rate case process



As of June 11, 2020.
* Action may take place depending on commission rules and procedures.
Credit: Cat Weeks
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

If the utility finds itself in a position of needing to raise its prices, the company must come before its state commission and file a rate case, unless it is already required to initiate rate proceedings at regular intervals. The reasons for a rate case filing are numerous, but they are generally due to investments the utility has been making, changes in expenses and cost of capital, and the impact of broader economic forces such as inflation or a sluggish economy.

A rate case is a quasi-judicial process, although there is no jury and the final outcome is determined by the commission. In some jurisdictions, the commission presides over the hearings and all aspects of a case, but in most instances the commissioners get involved at the end of the proceeding and make their decision after reviewing the entire case record. The process is complicated and costly, sometimes taking as long as two years to be completed. Utilities do not enter into a rate case lightly.

The process begins with the utility's filing, which includes the testimony of several witnesses. The company quantifies the additional revenue it believes it needs to recover its operating costs, depreciation expense and taxes, and to allow its shareholders to earn a reasonable return. Each witness supports a specific aspect of the company's filing, e.g., depreciation, rate of return or pension costs. The commission will schedule a series of local public hearings that offer ratepayers an opportunity to speak their mind about whatever it is the utility is proposing. The commission is not supposed to let the comments from these hearings factor into their decisions on case-specific issues because the comments are not part of the case record. However, commissioners are not immune to the public outcry that often accompanies a rate case.

At some point during the process, after the intervenors have had a chance to digest the company's application, they will file their direct testimony, in which they outline their recommendations on the proposals put forth by the company. The parties will critique nearly every aspect of the utility's request, with the recommendations tailored to suit the needs of the relevant constituent group. Usually the commission's staff, a state attorney general and/or another state agency represent the public interest, primarily as it relates to residential customers, and their stance on rate case matters tends to be very different from that of the company. Every jurisdiction is different, but intervening entities can also include an individual large commercial or industrial customer or a consortium of such customers that may have a rather limited focus, a municipality or group of municipalities in which the utility operates, a group seeking to advance an environmental agenda and/or an organization that advocates for the needs of a particular segment of the population, such as retired ratepayers.

After this initial round of testimony, more testimony is filed in which the parties address their concerns with the positions taken in earlier rounds, and sometimes they will hold firm on their positions. But more often than not, the parties will begin settlement discussions to see if they can arrive at some sort of middle-of-the-road position on some or all of the outstanding issues in the proceeding. At the very least, this will narrow the gap between the parties' respective revenue requirement positions. If a consensus is reached regarding a stipulated rate increase, then the parties — at least some of them — will sign a settlement and file it with the commission. A settlement will generally shorten the time frame required to complete a rate case, since some of the other steps in the process can be eliminated.

If the parties are unable to reach a comprehensive agreement on the outstanding issues, the case will proceed on a litigated track, and the commission will need to rely on the evidence in the case as it develops a final decision on the issues. Frequently, a commission administrative law judge will issue a proposed order, effectively a recommendation,

for the commissioners to consider for approval. At this point, the commissioners will hold a meeting and vote on a final order, and some commissions allow the public to listen in on their dialogue. The public may still not know what is included in the order but at least can feel that they are informed. Other commissions will simply issue their order with little advance notice.

Although the commission may have issued a final order, the case may not be completed, especially litigated cases, as the utility and some of the intervenors may not agree with aspects of the commission's order. The company may feel that the authorized ROE is out of line with prevailing industry returns, or the consumer advocate or attorney general may contend that the commission had no legal justification for allowing implementation of a rate rider.

For parties with objections to the final outcome, the initial remedy would be in the form of a request for reconsideration, and the parties can attempt to substantiate their claims. From that point, the commission could either simply affirm or amend the order in light of a new or compelling argument presented during the reconsideration process.

Once the commission acts on the requests for reconsideration, any further amendatory requests would need to be made in the form of a legal appeal to a court with jurisdiction over the commission's orders. The appeals process can be drawn out, and it is not uncommon to see utility rate matters get tied up in court for several years. However, a commission order being on appeal does not mean that the utility is prohibited from filing a new rate case, as the appeal process does not have to play out in its entirety before another case can be filed. By and large, most commission decisions typically have been upheld by the courts, but the court may remand or reverse a decision if the commission's ruling is determined to be in violation of the law.

The importance of the test year

An analysis of a utility's revenue requirement begins with the selection of a test year, which is simply a 12-month period used as a base line in examining the utility's actual revenues and expenses if a historical test year is chosen or a future 12-month period with a forecast of the utility's revenues and expenses if a fully forecast test year is selected. A hybrid approach of both methods can also be used.

Using its test-year financial data as the starting point, the utility proceeds to make adjustments for items that may not be representative of its operations going forward. For example, the utility may have filed a rate case on Jan. 1, 2020, and chosen a test year that ended on June 30, 2019. A wage increase for the company's unionized employees may have become effective in September 2019, but is not reflected in the financial results for the 12 months ended June 30, 2019. The approved rate change will not be implemented until late-2020, at which point the wage increase has long since been in place, so the utility will adjust its per-books labor expense level upward to reflect this in the new case.

Alternatively, the summer cooling season for an electric utility during the test year could have been abnormally hot, and the company's kilowatt-hour sales could have been abnormally high. In that situation, an adjustment to the utility's test year revenues could be warranted, which all else being equal, would have the effect of showing a greater need for a rate increase. Ideally, the utility will seek to select a test year and make appropriate adjustments to provide a representative picture of what its financial performance will be like during the first year that the new rates are in effect.

Determining the revenue requirement

Since the traditional utility revenue requirement formula is based on costs, the process used to determine a utility's revenue requirement begins with the expression below. At this point, this is pure accounting and not unique to the utility space.

Revenue	Operating expenses	Depreciation	Taxes	**Net operating income**

In the next equation, revenue has been isolated and renamed "revenue requirement."

Net operating income + Operating expenses + Depreciation + Taxes = **Revenue requirement**

In the third iteration of the formula, net operating income, or NOI, has been replaced with the product of the utility's rate of return and its net assets. Since NOI includes the funds necessary to service all the utility's securities, e.g., debt, preferred stock and common stock, NOI must equal the product of the overall rate of return, or cost of capital, and the asset base. It is essentially the pool of money left over for investors after all the direct costs of doing business have been satisfied.

Rate of return × Net assets + Operating expenses + Depreciation + Taxes = **Revenue requirement**

In the fourth version, net assets has been renamed "rate base," which is a regulatory term that refers to the company's net utility assets, as determined by the commission, that are "used and useful" in the provision of service to ratepayers.

Rate of return × Rate base + Operating expenses + Depreciation + Taxes = **Revenue requirement**

Calculating the rate change

The above equations give rise to the company's total revenue requirement. However, the process must shift to the determination of the *rate change* that is required so that the company can collect its total revenue requirement. In simple terms, the commission reviews the utility's revenue and prudent costs for the selected test year and considers the resulting NOI for that period. If the company's NOI is determined to be inadequate, a rate increase is authorized. Conversely, if the NOI is found to be too high, a rate reduction can be ordered.

The following expression is the common formula for calculating a rate change, which in industry speak means the additional revenue the utility is proposing, or that an intervenor is recommending or that the commission is authorizing. The equation has three variables — or four, if the tax factor is considered — and these variables are shown with an asterisk; everything else is the result of plugging the appropriate variable into the equation.

Calculating the rate change

	Rate of return*
x	Rate base*
	Required NOI
—	NOI under current rates*
	NOI deficiency
x	Tax factor
	Rate adjustment

*Indicates that figures are variables and not the result of a calculation in the equation.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Rate of return — The first variable in the expression is the rate of return, which is the result of a weighted-average cost of capital calculation and generally includes the cost of debt and the cost of equity.

While the cost of a company's debt securities can be gleaned by reviewing the stated cost rates for each particular debt issue, there is no stated return for common equity. If an investor were to buy a utility stock, he or she would not be promised any specific return on their investment. There is no coupon rate for common equity, and the return will simply be the sum of any dividend income the investor will receive over time and the price appreciation or reduction experienced during the holding term.

What does this mean in terms of calculating the ROE? It means that informed individuals can disagree on what the appropriate return should be, even though they rely on established financial theory to arrive at an estimate for the cost of equity. In utility rate cases, the estimated ROE is very subjective, and even slight variations to the inputs in the formulas commonly used can produce significant differences between what each party thinks is an acceptable equity return for the company.

Rate base — The second variable shown in the rate change calculation is the rate base value. At a very basic level, rate base is a utility's prudent capital investment, as authorized by the commission, net of accumulated depreciation. Rate base may include other items such as commission-approved deferred costs known as regulatory assets, certain pension contributions and items that may be used to offset the value of rate base, such as accumulated deferred income taxes, or ADIT, and customer deposits. But in its simplest form it is the used-and-useful net asset base from which the utility provides service to customers and upon which it is allowed to earn a rate of return.

For electric utilities doing business in non-restructured jurisdictions, rate base includes the net value of investments in generation, transmission and distribution infrastructure. In states that have restructured their electric markets and where the generation supply is now competitively procured, the generation assets are no longer included in the rate base calculation. In restructured jurisdictions, legacy utility generation plants have either been divested entirely to a merchant generation company or transferred to an affiliate of the utility, and these plants are no longer economically regulated.

For gas utilities, rate base includes the pipes and mains that are used in the provision of distribution service. But when it comes to valuing rate base, many other items can be included in or used to offset the net value of the utility's plant and equipment. For example, equipment inventories are typically included in rate base, as is cash working capital, which is the amount of cash required by a utility to pay the day-to-day expenses incurred to provide service to customers.

Calculating rate base can be complicated due to certain policy considerations. For example, what period of time should the commission use to measure rate base? Should it be a specific historical date, with "known-and-measurable changes" recognized? Should it be a date in the future that contains projections? Using projections generally produces a higher rate base. Should rate base be determined as of the end of the rate case test year — a year-end valuation — or should it be based on the average of the monthly rate base values over the course of the test year? Does the commission include construction work in progress, or CWIP, in rate base?

Including CWIP in rate base allows the utility to collect a cash return on the asset under construction prior to completion. If CWIP is not included in rate base, accounting standards dictate that the utility is to record a non-cash adder known as allowance for funds used during construction, or AFUDC, which represents the accrued financing charges associated with CWIP that is not yet included in rate base. AFUDC is equal to the assumed rate of return on the CWIP balance, with the amount included on the utility's income statement during the period in question. With AFUDC, earnings remain whole during construction, but there is no impact on the company's cash flows. Once the plant is completed, the accumulated AFUDC is generally included in rate base as plant-in-service. Several states have statutes that prohibit the inclusion of CWIP in rate base.

Regulatory assets, which are also frequently included in rate base, are unique to utilities and are the product of accounting standards. A regulatory asset is created when the utility's regulator authorizes the deferral, to a future period, of a given expense — including depreciation and storm restoration expense — that would normally be recorded on the company's income statement during the present period. Accounting convention says that the prospects for future recovery, in rates, of the cost item in question must be probable for an expense to be deferred. The deferred costs give rise to a regulatory asset that is likely, but not guaranteed, to be included in rate base at some point in the future and amortized over a number of years. Regulatory assets are not generally physical plant assets, and this is one of the reasons why simply taking the value of the company's net plant as a proxy for rate base is not advisable.

State utility commissions have approved the use of deferral techniques for various costs in recent years, perhaps most prominently for costs incurred to restore service after large storms. Few industry participants ever imagined that similar measures might need to be taken to respond to the effects of a pandemic. However, several jurisdictions are examining the merits of using deferral treatment to address changes to utility cost profiles and "lost revenues" due to COVID-19.

Proposals to defer lost revenues are similar to what would occur with a decoupling mechanism. A decoupling mechanism essentially allows the utility to defer fixed costs that it fails to recoup through volumetric charges due to customers' participation in conservation programs, weather fluctuations or altered economic conditions, changes in demographics or even the departure of a large customer. The utility is then allowed to recover the deferrals associated with the unrecovered fixed costs through a mechanism over a period of time, generally with carrying charges on the deferred balance.

ADIT arises due to the tax timing differences created by the alternate depreciation calculations from the straight-line method, which is used for financial statement purposes, and the accelerated method that is used for tax purposes. The utility is collecting, at present, a portion of the tax liability it will owe at some point in the future, and the cost-free funds need to be accounted for. ADIT can either be accounted for as a reduction to rate base, as is the case in most jurisdictions, or as a source of zero-cost capital in the rate-of-return calculation. If an analyst were to leave ADIT out of the rate base calculation, they would be artificially inflating their estimate of the utility's rate base, and accordingly, its revenue requirement.

Examples of capital structures determined using these methodologies are depicted above. On the top of the figure, a traditional capital structure is shown, while the one on the bottom includes deferred income taxes as a zero-cost item. The vast majority of jurisdictions use a traditional capital structure; Arkansas, Florida, Indiana and Michigan rely on the alternative technique.

Capital structure (%)

Atmos Energy Corp. — PSC Case No. 2018-00281

Type of capital	Percent of capitalization	Cost rate	Weighted-cost rate
Long-term debt	39.73	4.56	1.81
Short-term debt	2.21	3.40	0.08
Common equity	58.06	9.65	5.60
	100.00		7.49

Regulatory capital structure

Northern Indiana Public Service Co. — IURC Ca. No. 44988

Type of capital	Percent of capitalization	Cost rate	Weighted-cost rate
Long-term debt	36.80	4.94	1.82
Customer deposits	1.22	4.91	0.06
Deferred income taxes	21.10	0.00	0.00
Prepaid pension asset	-7.43	0.00	0.00
Post-employment liability	1.39	0.00	0.00
Post-1970 investment tax credits	0.04	7.69	0.00
Common equity	46.88	9.85	4.61
	100.00		6.50

Data compiled June 11, 2020.
PSC = Kentucky Public Service Commission; IURC = Indiana Utility Regulatory Commission
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

NOI under current rates — The third variable in the equation is NOI under current rates, which is basically the NOI the utility would be expected to achieve if its rates were to be left unchanged. This figure is pulled from the financial exhibits the utility submitted in its rate case application and includes adjustments such as employee wage increases. It is another variable that can vary considerably in a rate case.

As an example, increased executive incentive compensation expense, all else being equal, would lead to a lower NOI under current rates, and, working through the rate change formula shown previously, a greater need for a rate increase. But this variable cuts both ways. The intervenors in a rate case might recommend that a portion of the company's executive incentive compensation expense be disallowed and excluded from the calculation of this variable if it is demonstrated that the cost was tied to a financial metric that only benefitted shareholders. Disallowing recovery of these costs would result in a higher NOI under current rates and would lead to a lesser need for a rate increase. The list of potential NOI adjustments is extensive, and there is ample opportunity for the company and the parties to propose adjustments that can significantly impact the revenue requirement in the case.

The required NOI will be compared to the NOI under current rates, and the difference is referred to as the NOI deficiency, indicating a need for a rate increase, or the NOI sufficiency, suggesting that rates should be reduced. This is a net amount that needs to be grossed up for taxes, since the utility is permitted to collect amounts that will be remitted to its taxing authorities. Generally speaking, corporate taxes will take a 20%-25% bite out of pretax income, so multiplying the NOI deficiency or sufficiency by about 1.35 — the reciprocal of 75% — will give the top-line revenue change number.

Rate design

Once a utility's revenue requirement has been determined, the task of establishing a new set of tariffs has to be tackled. The approved change in revenues needs to be allocated to each customer class before new rates can be implemented. Generally speaking, the utility's revenue requirement is supposed to be collected from each customer class according to the relative share of the company's cost to serve those customers. There are different methodologies for doing

this, but they all attempt to allocate the utility's cost of service in a justified manner, at least in theory. The reality is that sometimes one class ends up being allocated a disproportionate share of the revenue requirement. Residential customers vote and utility matters tend to be politicized, and regulators, especially those that are elected to their positions, may be reluctant to elicit backlash from residential ratepayers. In such a situation, the commercial and industrial customer classes could be hit with an above-average share of a rate increase. On the other hand, some jurisdictions may be trying to attract new businesses to their area for economic development reasons and could be inclined to allocate a larger-than-average share of any approved revenue increase to the residential class. The circumstances can vary widely by jurisdiction, and there is no one-size-fits-all approach to revenue requirement allocation. But inter-class subsidies do exist.

The revenue requirement for each class will need to be divided by the estimated number of units of the product that will be sold over the next 12 months. For an electric utility that serves 75,000 residential electric customers that are forecast to use, on average, 1,000 kilowatt-hours per month, 900 million kilowatt-hours are sold in total, or 900,000 megawatt-hours, per year. If the utility has been authorized a $7 million base rate hike, of which $3 million has been allocated to the residential customer class, then that $3 million in additional revenue will need to be converted into a per-unit charge that will ultimately be used in determining each customer's monthly bill. Dividing $3 million by 900 million kilowatt-hours gives 3 tenths of 1 cent. So a residential customer of this utility would be paying an extra $3 per month going forward, or $36 per year.

Estimating the ROE

There are several methodologies for estimating an ROE for a utility in a rate case, although there are a select few that are consistently recognized by utility commissions.

Discounted cash flow, or DCF — The DCF model calculates ROE by dividing the company's dividend, in dollars, by its observable market price and then adding an assumed growth rate, as shown below.

If a company's dividend is expected to grow at different rates over a period of time, then a multistage DCF approach can account for this. The DCF model is one of the standard formulas for estimating ROE in rate cases, but as is the case with any formula or model, the output is only as good as the inputs, so it is important to make reasonable assumptions regarding the growth rate.

Capital Asset Pricing Model, or CAPM — The CAPM is also given significant weight by the commissions and is depicted below.

The CAPM uses as the starting point for determining the ROE the yield on a long-term U.S. Treasury bond. This rate is the risk-free rate of return in the formula. Since all securities are, by definition, riskier than the riskless government bond, an ROE for those securities will need to reflect some sort of premium over the risk-free return. The CAPM approach adds the product of the stock's beta — the systematic risk factor for the company, calculated by looking at the relationship between the stock's historical price movements and those of the broader market — and a market return premium. The market return premium is simply the expected "excess" return for the stock market over the risk-free rate and is also calculated with historical price movements in mind. The sum of the risk-free rate and the product of the stock's beta and the market return premium will give an estimate of an appropriate ROE for a utility.

Comparable earnings — Many commissions consider the results of a comparable earnings analysis when establishing an authorized ROE. This approach assumes that a given investment should earn a return similar to that of investments with similar risk characteristics. Generally speaking, utility commissions have a preference for the DCF and CAPM methodologies and, instead of relying on one or the other, will often take an average of the ROE estimates these two models produce.

Certain factors may impact the ROE ultimately authorized. For example, if the utility is an electric distribution company with no regulated generation assets, the commission may consider this company to be a lower-risk entity and authorize a slightly lower ROE than it would for a fully integrated electric company. In addition, commissions may authorize a slightly lower ROE for companies that utilize several adjustment clauses that allow for timely recognition of changes in certain expenses outside of a general rate case. Over the years, there have also been ROE authorizations that reflected incentive awards for superior management performance or less-than-stellar service quality.

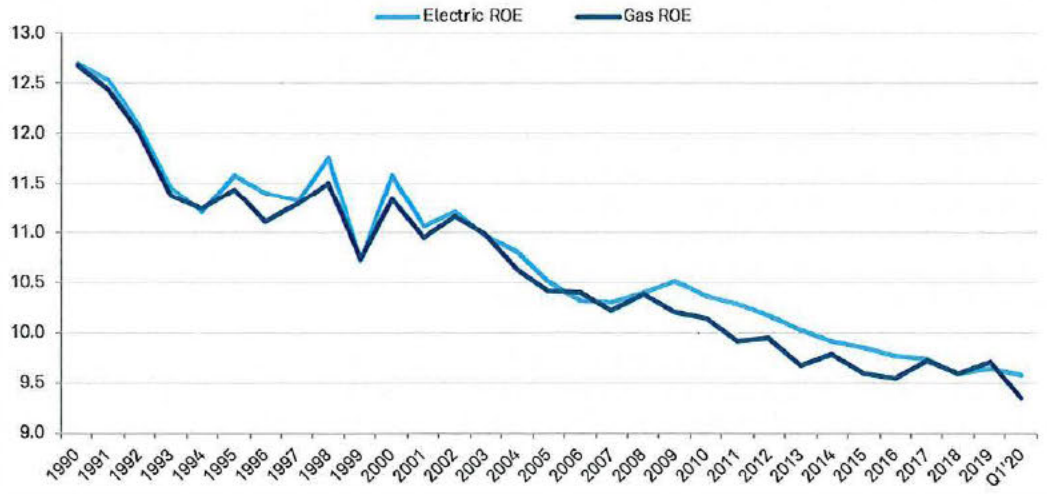
The bottom line is that there is no "correct" way to calculate an appropriate ROE. As is the case with most financial models, the output is only as good as the input, which means that estimating the variables in any ROE formula is an important undertaking.

Authorized Energy ROEs – a temporal analysis

Through the first three months of 2020, the average ROE authorized for the electric utilities nationwide was 9.58%, including limited-issue proceedings where in many instances incentive ROE premiums were included; excluding these cases from the data, the average authorized ROE was 9.45%. The average ROE authorized for the gas utilities over this same period was 9.35%, a historic low. These returns are roughly 300 basis points lower than they were in 1990. As demonstrated in the following chart, there are relative movements from one year to the next, but the trend is clear.

The gap between the authorized ROEs for electric and gas utilities was relatively tight in the early 1990s, when authorized ROEs for both sides of the business tended to move in lockstep. Beginning later that decade, the gap narrowed even further following the advent of electric industry restructuring. As certain states restructured their electric markets, their utility commissions began to authorize slightly lower equity returns for the electric utilities that had become essentially just transmission and distribution, or T&D, utilities. Thus, the ROEs shown for the electric utilities reflect a blend of ROEs approved for integrated and T&D-only utilities.

Average electric and gas authorized ROEs (%)



Data compiled on June 9, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

The relationship between authorized ROEs for electric and gas utilities generally held for much of the 1990s and continued into the 2000s, and around the middle of the decade, the gap began to widen. In the last 10 years or so, the gap has been as much as 30 to 40 basis points, largely due to ROE premiums that are being accorded certain generation projects. Due to the sheer magnitude of the costs involved with building new generation, regulators in some jurisdictions have found it worthwhile to incentivize utilities to proceed with these projects through plant-specific ROE premiums. In recent years, however, the returns have again begun to narrow.

Authorized vs. earned ROEs

A utility's authorized ROE is that which has been specified by the commission in a rate case for the company. It is used to calculate the overall return that is applied to the utility's rate base and is reflected in the rates that customers are charged. By contrast, the earned ROE reflects actual results achieved by the company over a period of time. The two numbers do not have to be equivalent and are usually not.

Commissions are required by the regulatory compact to provide the utility with a "reasonable opportunity" to earn the authorized ROE, but that is by no means a guarantee. Utilities are not guaranteed any sort of return by their regulators, although for some regulatory frameworks that are based on a formulaic or performance-based ratemaking structure, this is not necessarily true. But those circumstances are not the norm.

Assuming the commission did not adopt any meaningful disallowances in the utility's most recent rate case and the test year that was used in the case was not too old, the company may be able to earn that return if it operates the business efficiently. However, for those utilities that are continually subject to regulatory lag — meaning that their authorized revenue requirement does not reflect the full value of the investments that are currently being used to provide service — they may never be able to earn their authorized ROEs.

Rate case example

In a gas rate proceeding decided in 2019 for Atmos Energy Corp., the company had supported a $14.4 million rate increase. The company used a test year that was fully forecasted at the time the case was initiated. Ultimately, the company supported a rate base that was valued at $496 million, a 10.4% ROE and a 7.93% overall return. Atmos said that its requested increase was necessitated by a "declining return on equity and inadequate revenue to continue to provide the quality of service required by the commission and demanded by our customers."

Atmos Energy Corp.

	Company supported	PSC ruling	Approx. difference ($M)
Rate of return*	7.93%	7.49%	3
x Rate base ($M)*	496.0	424.9	8
Required NOI ($M)	39.3	31.8	
— NOI under current rates ($M)*	28.7	32.0	4
NOI deficiency ($M)	10.6	-0.2	
x Tax factor	1.35	1.35	
Rate adjustment ($M)	14.4	-0.3	15

Data compiled June 11, 2020.
NOI = net operating income; PSC = Kentucky Public Service Commission
* Rate case variables.
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence; PSC Case No. 2018-00281

In the Kentucky Public Service Commission's final order in the case, the commission required the company to reduce base rates by $0.3 million based on a 9.65% ROE, a 7.49% overall return and a $424.9 million rate base. The authorized overall return was lower than that supported by the company, the adopted rate base was lower and the NOI under current rates was higher. Each of these adjustments served to lower the revenue requirement relative to the rate increase that had been supported by Atmos. As shown in the accompanying table, the PSC's adjustments in this proceeding totaled roughly $15 million, representing the difference between the $14.4 million rate increase supported by Atmos and the $0.3 million reduction ordered by the commission.

Using the formulas below, RRA determined that about $3 million of the total difference stemmed from the PSC's decision to adopt a lower rate of return that than supported by the company. There was about $8 million of difference attributable to various reductions to rate base. NOI adjustments accounted for the remaining roughly $4 million of the revenue requirement difference.

On balance, RRA deemed this decision to be negative from an investor viewpoint. Although the 9.65% ROE authorized by the PSC approximated the average of returns accorded gas utilities nationwide during the 12 months preceding the decision, the PSC rejected Atmos' request to terminate its pipeline replacement program, or PRP, rider and reflect all prospective costs associated with its accelerated infrastructure upgrades in annual base rate filings. However, the commission acknowledged certain concerns the company had with the nature of the PRP rider proceedings. In addition, the PSC took issue with the company's failure to request preapproval of certain projects through a process outlined in state law. The commission made it clear that it would view similar actions in the future unfavorably.

Revenue requirement differences (approximate)

Variable #1 Difference in return	Atmos' ROR	7.93%
	— PSC ROR	— 7.49%
	ROR difference	0.44%
	x PSC rate base	x $424.9 (million)
	Net revenue req. difference	$1.9 million
	x Tax factor	x 1.35
	Revenue req. difference	$3 million
Variable #2 Difference in rate base	Atmos' rate base	$496 million
	— PSC rate base	— $424.9 million
	Rate base difference	$71.1 million
	x Atmos's ROR	x 7.93%
	Net revenue req. difference	$5.6 million
	x Tax factor	x 1.35
	Revenue req. difference	$8 million
Variable #3 Difference in NOI	PSC NOI	$32.0 million
	— Atmos' NOI	— $28.7 million
	NOI difference	$3.3 million
	x Tax factor	x 1.35
	Revenue req. difference	$4 million

Data compiled June 11, 2020.
PSC = Kentucky Public Service Commission; ROR = rate of return; NOI = net operating income
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence; PSC Case No. 2018-00281

Rate case activity

Electric and gas rate case activity has been quite robust in recent years. Through the first five months of 2020, there were 48 major rate case decisions in the U.S. — 31 electric and 17 gas — and RRA expects an additional roughly 30 or more to be decided by year-end, which would bring the total number of decisions in 2020 to about 80.

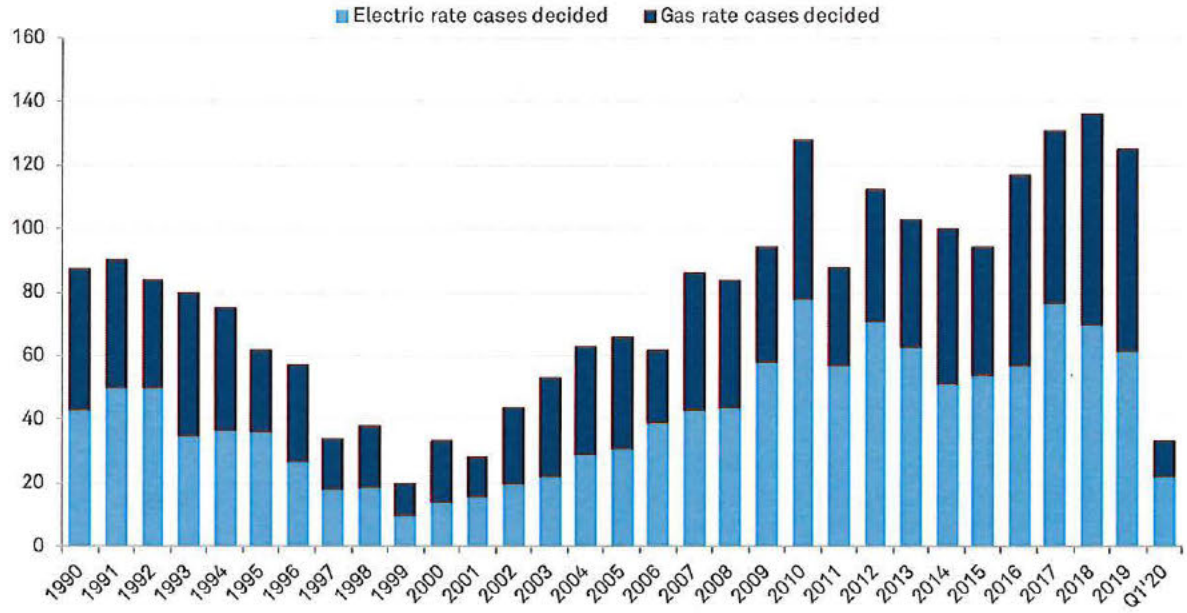
Even though recent activity is fairly robust by current standards, it still has not reached the levels seen in the 1980s, when as many as 200 cases were decided in a single year, 1982. This level of regulatory activity was driven largely by the need to achieve rate recognition of new large-scale generation facilities, particularly nuclear facilities, inflation and rising interest rates.

Rate case activity continued to be significant through the first half of the 1990s but declined significantly in the latter part of the decade, reaching a 35-year low of 20 cases in 1999. This trend was largely due to cessation of major construction programs, the specter of electric industry restructuring/retail competition and declining interest rates.

During this period, "competition" for the electric generation portion of utility service was the industry's buzzword, and many utilities were attempting to minimize their retail prices in an effort to remain "competitive." In several states, the utility commissions established multiyear rate plans, under which rates were frozen during a transition period in which the utilities were permitted to recover stranded costs, i.e., the costs that were considered to be unrecoverable in a competitive retail market for electric generation service. The trend toward expanding retail competition has since been largely halted.

In addition, at the time interest rates were comparatively low, and many utilities had previously been authorized rates of return that were deemed to be much higher than those they could expect to be awarded in a new rate case. Also, construction activity had dropped following the end of the 1980s construction boom, and there were fewer large capital investments for which utilities would typically seek rate recognition. Consequently, there was little expectation that

Decided electric and gas rate cases



Data compiled June 9, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

a rate case would result in approval of a higher revenue requirement. In addition, technological improvements that reduced operating costs may have allowed the companies to delay filing new rate proceedings.

From 2000 through 2006, rate case activity increased somewhat but remained relatively sluggish due to the extensive rate freezes that had been required by many of the states that implemented retail competition as well as persistent declines in interest rates and authorized ROEs and a focus on cost-cutting and management efficiency.

Rate case activity picked up more sharply beginning in 2007, as the previously mentioned restructuring-related rate freezes expired and traditionally structured companies that had remained out of the rate case arena found that they could no longer use operational efficiency gains to offset the revenue requirements associated with new investments and increasing employee costs.

Rate case activity hit another peak in 2010 when 129 cases were decided, and in recent years, rate cases have continued to occur at a fairly brisk pace as utilities seek to: (1) achieve rate recognition of new investment in electric generation to meet new demand and satisfy environmental compliance obligations in vertically integrated jurisdictions as well as to meet renewable resource mandates; (2) reflect in rates electric and gas transmission and distribution infrastructure investments needed to remediate damage caused by severe weather, improve reliability, protect against future outages, replace aging infrastructure particularly on the gas distribution side in the wake of pipeline incidents, and deploy new technologies such as smart meters in order to facilitate energy conservation programs and renewables initiatives; (3) recover increasing employee healthcare and pension costs; and (4) address the earnings impact of reductions in sales volumes due to weather, customer participation in energy efficiency programs and weak economic conditions.

RRA expects this level of activity to continue for the foreseeable future, as many of the drivers of rate cases noted above represent complex issues that will need to be addressed over the long term. For a full list of past and pending rate cases, rate case statistics and upcoming events, visit the energy research home page.

Prevalence of adjustment clauses

Utility industry stakeholders have developed innovative techniques to achieve timely rate recognition of investments in certain projects and increases in key expenses. One such technique is the adjustment clause, which effectively shifts the risk associated with recovery of the expense in question from shareholders to customers, because, if the clause operates as designed, the company is able to change its rates to recover its costs on a current basis without any negative effect on the bottom line and without the expense and delay that accompanies a rate case filing.

The electric and natural gas utilities' use of adjustment clauses to recover variations in certain costs outside of the traditional rate case process has its origins in the 1973 Arab oil embargo, when fuel costs skyrocketed, leaving the utilities with no way to recover the increased costs in a timely manner. During these years, utility earnings were under considerable pressure, a situation that prompted some jurisdictions to establish a more constructive framework to allow more timely recovery of cost increases that were beyond the control of the utilities. The result was the creation of the fuel adjustment clause.

Over the ensuing years, the use of adjustment clauses expanded to include other expenses that are outside the control of the utility or are required by law or rule, such as environment compliance costs, conservation program costs, pension costs, municipal taxes and franchise fees, the pass-through of transmission-related costs allocated to the utility by the Federal Energy Regulatory Commission and storm costs, to name a few.

More recently, the use of adjustment clauses was expanded further to include certain types of new generation and T&D investment and to mitigate the impacts of fluctuations in sales due to weather, energy conservation and/or economic conditions. For a discussion of the most prominent adjustment clauses in place for the electric and natural gas utilities in the U.S., refer to the 11/12/19 Topical Special Report entitled Adjustment Clauses: a state-by-state overview.

Although not adjustment clauses per se, some jurisdictions have approved the use of surcharges to recover specific one-time items, such as excess storm restoration costs, while expense trackers have also been widely adopted. Expense trackers provide for the deferral of variations in certain costs for potential recovery at a future time, when the commission will consider the accumulated balance for inclusion in rates. Although an expense tracker is designed to keep the utility's earnings whole, rates, and accordingly cash flows, do not change on a current basis.

Alternative ratemaking

Another construct that is akin to a rate case but is designed to address ratemaking in a more streamlined fashion is broadly known as "alternative ratemaking." It can mitigate regulatory lag, which as discussed earlier can prevent the utility from earning its authorized return. Alternative regulation plans can be broadly or narrowly focused.

Broad-based plans include formula-based ratemaking plans that generally refer to frameworks where the commission has established a revenue requirement, including a target ROE, capital structure and rate of return for an initial rate base as part of a traditional cost of service base rate proceeding. Once the initial parameters are set, rates may adjust periodically to reflect changes in expenses, revenue and capital investment. These changes generally occur on an annual basis, and there may be limitations on the percentage change that can be implemented in a given year or period of years.

Under multiyear rate plans, the commission approves a succession of rate changes that are designed to take into account anticipated changes in revenues, expenses and rate base. The commission may approve a static authorized ROE or the plan may provide for adjustments to the ROE during the plan's term. These plans often include true-up mechanisms to ensure that the company makes the investments it has committed to make at the inception of the plan. The plans often include earnings sharing mechanisms and may also include performance-based ratemaking provisions.

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RRA Regulatory Focus: Adjustment Clauses

Use of adjustment clauses (as of November 2019)

State/ Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/gas commodity/purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
ALABAMA												
Alabama Power Co.	SO	Elec.	✓ *	--	--	--	✓	✓ *	✓ *	--	--	✓ *
Spire Alabama Inc.	SR	Gas	✓ *	--	--	✓ *	--	--	--	--	--	✓ *
Spire Gulf Inc.	SR	Gas	✓ *	--	--	✓ *	--	--	--	--	--	✓ *
ALASKA												
Alaska Electric Light and Power Co.	AVA	Elec.	✓	--	--	--	--	--	--	--	--	--
Enstar Natural Gas Co.	ALA	Gas	✓	--	--	--	--	--	--	--	--	--
ARIZONA												
Arizona Public Service Co.	PNW	Elec.	✓	✓	--	✓ *	✓	✓	--	--	✓	✓ *
Southwest Gas Corp.	SWX	Gas	✓	✓	✓	-- *	--	--	--	✓ *	--	✓ *
Tucson Electric Power Co.	FTS	Elec.	✓	✓	--	✓ *	✓	✓	--	--	--	✓ *
UNS Electric Inc.	FTS	Elec.	✓	✓	--	✓ *	✓	--	--	--	✓	✓ *
UNS Gas Inc.	FTS	Gas	✓	--	--	✓ *	--	--	--	--	--	✓ *
ARKANSAS												
Arkansas Oklahoma Gas Corp.	--	Gas	✓	✓	✓	--	--	--	--	✓ *	--	✓ *
CenterPoint Energy Resources Corp.	CNP	Gas	✓	✓	✓	--	--	--	--	✓ *	--	✓ *
Entergy Arkansas LLC	ETR	Elec.	✓	✓	--	✓ *	✓	--	✓ *	✓ *	✓	✓ *
Oklahoma Gas and Electric Co.	OGE	Elec.	✓ *	✓	--	✓ *	✓	✓	✓	--	✓	✓ *
Black Hills Energy Arkansas Inc.	BKH	Gas	✓	✓	✓	--	--	--	--	✓ *	--	✓ *
Southwestern Electric Power Co.	AEP	Elec.	✓	✓	--	✓ *	--	✓	✓	--	✓	✓ *
CALIFORNIA												
Pacific Gas & Electric Co.	PCG	Elec.	✓	--	✓	--	--	--	--	--	--	✓ *
Pacific Gas & Electric Co.	PCG	Gas	✓	--	✓	--	--	--	--	--	--	--
San Diego Gas & Electric Co.	SRE	Elec.	✓	--	✓	--	--	--	--	--	--	✓ *
San Diego Gas & Electric Co.	SRE	Gas	✓	--	✓	--	--	--	--	--	--	--
Southern California Edison Co.	EIX	Elec.	✓	--	✓	--	--	--	--	--	--	✓ *
Southern California Gas Co.	SRE	Gas	✓	--	✓	--	--	--	--	--	--	--
Southwest Gas Corp.	SWX	Gas	✓	--	✓	--	--	--	--	--	--	--

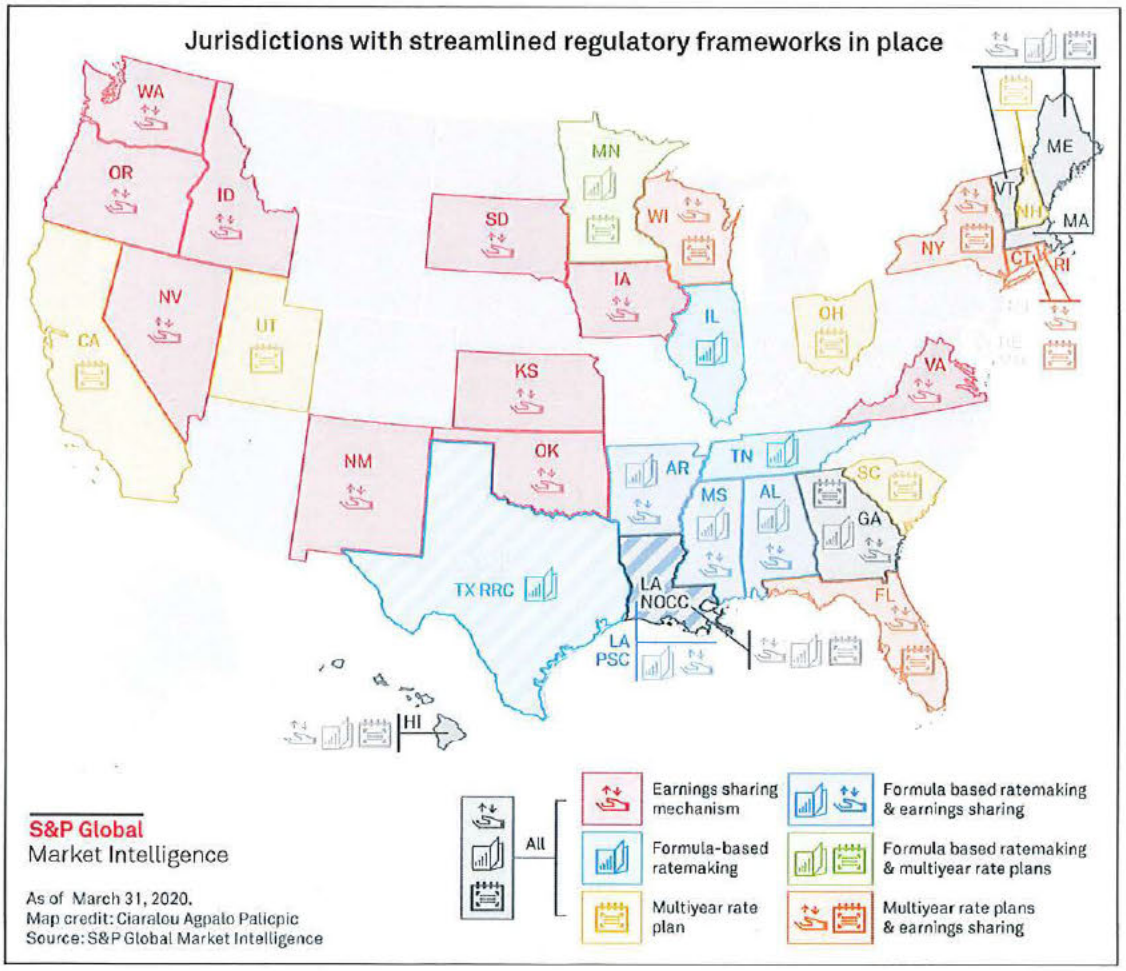
Earnings sharing mechanisms allocate to ratepayers and shareholders earnings that differ from a target or target range established by the commission. These mechanisms can also be implemented as part of formula rate plans and multiyear rate plans, in conjunction with a rate freeze, as part of a merger related filing or on a stand-alone basis as part of a rate case.

As of April 2020, 13 of the 53 jurisdictions followed by RRA had formula based ratemaking plans in place for at least one company in the jurisdiction, including jurisdictions where such plans were combined with other mechanisms. There are 17 jurisdictions in which a multiyear rate plan is in place for at least one utility, including instances where it is combined with other types of plans. Earnings sharing mechanisms are in place for at least one utility in 25 jurisdictions, on a stand-alone basis or as part of either a multiyear plan or a formula-based ratemaking mechanism. In a handful of other jurisdictions, legislation or commission rules permit these types of plans, but the commission has yet to approve a specific plan for one of the utilities.

Narrowly focused plans generally target a specific type of behavior or investment on the part of a utility. For example, some may allow a company to retain a portion of cost savings relative to a base level of some expense type, such as fuel, purchased power or pension costs.

Others might permit a company to retain for shareholders a portion of off-system sales or capacity release revenues. Still others provide a company an enhanced ROE for achieving operational performance targets, customer service metrics, reliability standards, demand reduction targets under energy conservation programs or for meeting or exceeding renewable portfolio standards.

In some instances, commissions have approved ROE premiums for specific types of plant investment when there was a preference for in-state generation versus wholesale power purchases, or in order to incent the deployment of renewable resource facilities.



While narrowly focused plans do not necessarily stream line the regulatory process the way that more broadly focused plans do, they do provide the utilities with the opportunity for earnings enhancement that could offset the impact of regulatory lag.

As utilities continue to grapple with increasing capital requirements and a shifting utility landscape, RRA expects increased use of these and new types of alternative regulation frameworks. For a discussion of the alternative ratemaking frameworks currently in place in each jurisdiction, refer to the Alternative Regulation section of the state Commission Profiles.

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Green bond finance and certification[1]

Financing of investments through green bonds has grown rapidly in recent years. But definitions of what makes a bond "green" vary. Various certification mechanisms have evolved to allow more granularity as well as continuity in assessment. Green bonds have been priced at issuance at a premium on average relative to conventional bonds, but their performance in the secondary market over time has been similar. A relatively large share of green bonds are in sectors subject to environmentally related credit risks. More consistent green bond standards across jurisdictions could help to further develop the market.

JEL classification: G24, O16, Q50.

Green bonds are fixed income securities which finance investments with environmental or climate-related benefits. Green bonds are an integral component of "green finance" more generally, which aims to "internalize environmental externalities and adjust risk perceptions" for the sake of increasing environmentally friendly investments (G20 GFSG (2016)). Economic theory teaches that a first-best solution for closing the gap between the private and social costs of pollution would be a mix of lump sum taxes and subsidies, with regulations to impose implicit prices following closely behind. Green finance can also help to alleviate these externalities, through market-based means. It acts by increasing the flow of funds to environmentally beneficial projects, essentially reducing their costs, as well as by heightening awareness of the financial risks related to environmental change.[2]

How can investors be sure that the proceeds of green bonds are invested in an environmentally friendly way, and not merely "green-washed" to give the appearance thereof? While there is no single global definition of what precisely constitutes an "environmentally beneficial" use of proceeds, different standards have gained acceptance among market participants. Various organisations have started to provide green label certifications that indicate adherence to particular definitions of green, including "shades" of green. In so doing, they align the incentives of those who want to invest in these bonds, and make it easier for asset managers to satisfy those preferences. Green bonds could also conceivably serve as a hedge against

1 The views expressed in this article are those of the authors and do not necessarily reflect those of the BIS. We thank Claudio Borio, Stijn Claessens, Benjamin Cohen, Dietrich Domanski, Kumar Jegarasasingam, Luiz Pereira da Silva and Hyun Song Shin for their valuable comments, and Agne Subelyte for providing excellent research assistance. We also thank the Climate Bonds Initiative for providing us with their data.

2 See the proceedings of the conference co-organised by the Official Monetary and Financial Institutions Forum (OMFIF), the BIS and the World Bank Group in Frankfurt on 13 July 2017; see also Weidmann (2017) and Pereira da Silva (2017).

environmentally related financial risks,[3] though in this case additional information is needed about the sensitivity of various bonds to such risks, beyond just the quality of "greenness" itself .

In this feature we provide an overview of the state of the green bond market. We show that, a decade into the development of the market, there still are numerous labels for green bonds. We highlight how the various certification mechanisms for greenness have been evolving so as to allow more granularity as well as continuity in assessment. Consistent with other research, we document that green bonds at issuance have been priced at a premium on average relative to conventional bonds, while their performance in the secondary market has been similar to other bonds if currency risks are hedged. Finally, we document that green bonds are exposed to environmentally related financial risks to a relatively high degree.

The rest of this feature proceeds as follows. After providing a definition of green bonds, we briefly review the growth and composition of labelled green bond issuance from two different sources. The third section examines and classifies the various green labels provided by the private sector to certify green bond issuance. The fourth section focuses on the market pricing, financial performance and risks of green bonds. The conclusion summarises the policy implications.

The market for green bonds

The market for bonds with a green label[4] has grown rapidly in recent years. It started with the European Investment Bank's "climate awareness bond" issued in 2007, which is widely seen as the first bond with a green label. A key catalyst for subsequent market development was the introduction in January 2014 by the International Capital Market Association (ICMA) of the Green Bond Principles, which are the basis for many of the existing green labels (ICMA (2014)). Since then, the market for labelled green bonds has expanded dramatically: in 2016, aggregate issuance surpassed the $100 billion mark, and the first half of 2017 has already seen a total issuance of around $60 billion (Graph 1). The market for green bonds is nevertheless still very small compared with the wider global bond market, with a share of less than 1.6% of global debt issuance in 2016.[5]

The composition of green bond issuance has evolved considerably over time (Graph 1, left-hand panel). Through 2013, issuance predominantly came from supranationals (ie international organisations such as the European Investment Bank). Issuers from advanced economies in Europe and the United States dominated in 2014 and 2015. Since 2016, issuers from emerging market economies (EMEs), particularly

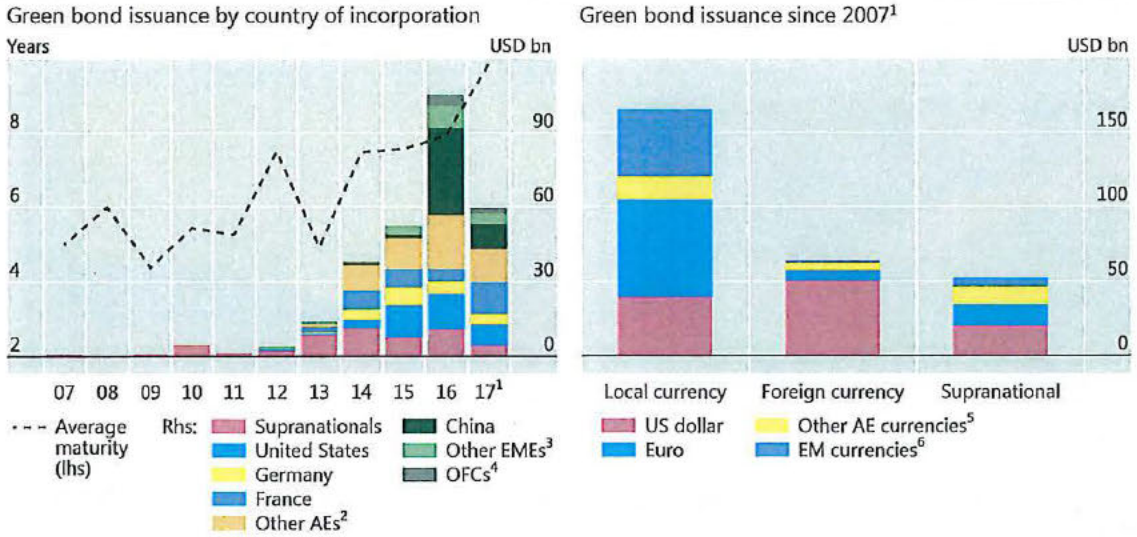
[3] Transition risks, ie the financial impact of changes in environmental regulation, are typically seen as the most significant risk bond investors face. Carney (2015) notes that "while a given physical manifestation of climate change – a flood or storm – may not directly affect a corporate bond's value, policy action to promote the transition towards a low-carbon economy could spark a fundamental reassessment".

[4] The universe of bonds for which proceeds are used for environmentally beneficial projects, but which do not carry a green label, is still likely to be quite large (Climate Bonds Initiative (2015)). But as the green label becomes more commonly used, it becomes more and more likely that issuers will seek this label to distinguish themselves.

[5] Based on an estimate of total global debt capital market issuance of $6.69 trillion in 2016 (see www.dealogic.com/insights/key-trends-shaped-markets-2016/).

Rapid growth in green bond issuance most recently in EMEs

Climate Bonds Initiative and Bloomberg lists of labelled green bonds, in billions of US dollars — Graph 1



[1] Up to mid-June 2017. [2] AT, AU, BE, CA, CH, DK, ES, EE, FI, GB, IT, JP, LU, LV, NL, NO, SE and SI. [3] AE, AR, BR, CL, CO, HK, IN, IR, KR, MX, PE, PH, PL, SG, TR, TW and ZA. [4] Offshore financial centres (OFCs): BM, CR, KY, MO, MU and VG. [5] AUD, CAD, CHF, GBP, JPY, NOK, NZD and SEK. [6] BRL, CNY, COP, HUF, IDR, INR, MAD, MXN, MYR, PEN, PHP, PLN, RUB, SGD, TRY, TWD and ZAR.

Sources: Bloomberg; Climate Bonds Initiative; authors' calculations.

corporates in China, have provided a large share of global issuance. The maturity of green bonds is typically medium-term, averaging between seven and eight years in 2014–16, but lengthened in the first half of 2017.

Issuance tends to cover a wide range of currency denominations. While supranationals have tended to issue in euros and dollars, some EME entities have made use of local currencies (Graph 1, right-hand panel).

Issuers of green bonds tend to be highly rated, with only a small fraction rated below investment grade (Graph 2, left-hand panel). More bonds with earmarked claims on the cash flows of an individual project (ie project bonds) could help diversify issuers and credit risks (Standard & Poor's (2017a), Caldecott (2012); Ehlers et al (2014)). Project bonds naturally entail higher credit risks, given the high initial uncertainties of new investment projects (Ehlers (2014)). These could cater to investors looking for higher yields.

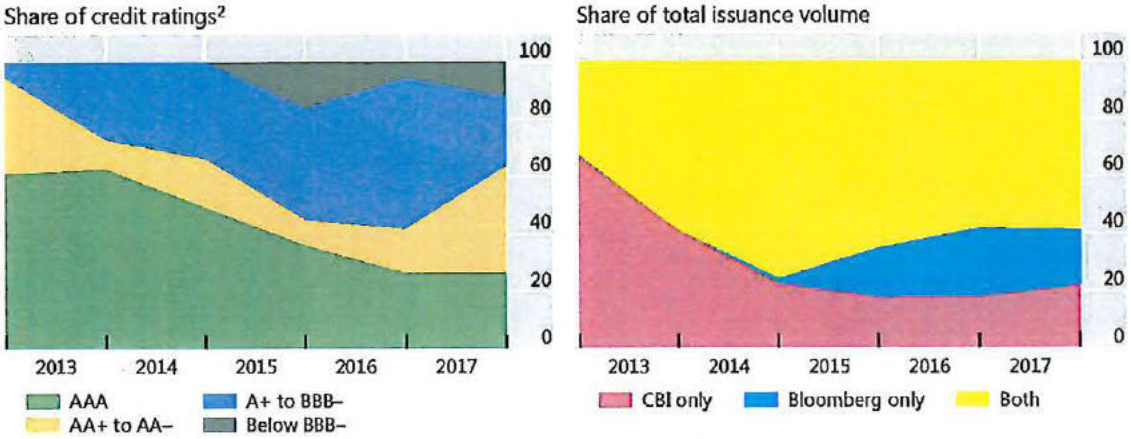
The above numbers aggregate figures from two widely used and broad-based lists of green bonds: those of the Climate Bonds Initiative (CBI) and Bloomberg. The CBI is an international non-profit organisation, funded by grants from non-profit and government sources as well as revenue from public sector contracts. Bloomberg is a widely used financial data and service provider. Both lists selectively include bonds with different types of green labels.

The two lists, and hence the corresponding volumes of issuance, do not coincide. The aggregate issuance of labelled green bonds from 2007 through the second quarter of 2017 in the CBI list equals $234 billion (comprising 1,092 individual issues). By contrast, Bloomberg counted $216 billion in green bond issuance (comprising 779 individual issues). Only $169 billion (624 individual issues) worth of bonds are

Distribution of green bond ratings and amounts issued[1]

In per cent

Graph 2



[1] For 2017, Issuance data up to mid-June. [2] Average rating of Standard & Poor's, Moody's and Fitch; expressed in Standard & Poor's categories.

Sources: Bloomberg; Climate Bonds Initiative (CBI); authors' calculations.

present on both lists. The Bloomberg list of green bonds was less extensive prior to 2014, but since then the overlap has been greater (Graph 2, right-hand panel).

Forms of green bond certification

For investment in green bonds to take off, it is important for both asset managers and their principals to be able to identify the bonds that actually have environmental or climate-related benefits. Asset managers may have the resources to make an informed judgment on their own. Indeed, global initiatives such as the Financial Stability Board's (FSB) Task Force on Climate-Related Financial Disclosures aim to make better environmental information readily available (FSB TCFD (2016)). Still, external certification allows asset managers to show beneficiaries that they are indeed investing in green bonds when requested to do so, and may be more cost-effective. A variety of forms of green bond certification have emerged, which all aim at ensuring that the use of funds and subsequent revenue is tied to green investment (Table 1).

The ICMA Green Bond Principles are so-called "voluntary process guidelines" that outline general criteria that most certification schemes follow. They were put together by major private financial institutions under the aegis of the ICMA (ICMA (2015)). The Principles provide prospective issuers with guidance on the key components of green bond issuance, namely: (i) the use of proceeds for environmentally sustainable activities; (ii) a process for determining project eligibility; (iii) management of the proceeds in a transparent fashion that can be tracked and verified; and (iv) annual reporting on the use of proceeds.

Though this section reviews international certification mechanisms available to any issuer, many jurisdictions have developed their own national taxonomies of what constitutes eligibility as a green bond. Most notably, China's Green Bond Finance Committee has issued a Green Bond Endorsed Project Catalogue (People's Bank of

Characteristics of different green bond identification and certification schemes — Table 1

	CBI Climate Bonds Certification	Green bond indices[1]	CICERO Second Opinions	Moody's Green Bond Assessments	Standard & Poor's Green Evaluations
Use of funds must be tied to green investment	Yes	Yes	Yes	Yes	Yes
Eligibility criteria differ by sector	Yes	Yes			Yes
Ex post monitoring/assessment				Yes	
Granular assessments of greenness			Yes	Yes	Yes
Quantitative weights for specific factors				Yes	Yes

[1] Bank of America Merrill Lynch, Barclays MSCI, Standard & Poor's and Solactive.

China (2015)). For large domestic markets, this is a sensible option, but to the extent that international harmonisation is an issue, domestic guidelines run the risk of limiting the value of any particular green certification scheme to the domestic investor base. The ongoing initiative to improve the consistency of definitions and methodologies for determining the eligibility of green projects across the jurisdictions of China and the European Union represents perhaps the most significant effort to address this issue (European Investment Bank (2017)).

Climate Bond Certification

As discussed above, the CBI maintains a list and database of green bonds issued since 2009. The bonds in its database have green labels, but inclusion in the database does not constitute an opinion by CBI as to the correctness of the label.

The CBI also provides standards and a certification procedure. While the Green Bond Principles are very general, the CBI's Climate Bonds Standard establishes sector-specific eligibility criteria to judge an asset's low carbon value and suitability for issuance as a green bond. Assets that meet the CBI standard are then eligible for Climate Bond Certification, after an approved external verification that the bond meets environmental standards and that the issuer has the proper controls and processes in place.

A limitation of the CBI standard is that it does not necessarily mandate monitoring and verification on an ongoing basis (Table 1, first column). It is highly useful for investors to have an entity regularly renew its certification, particularly if they intend to maintain the investment over a multi-year horizon.

Green bond indices

Green bond indices identify specific bonds as green via a stated methodology, and allow investors to invest in a portfolio of green bonds to diversify risks (Table 1, second column). To this extent, the green bond index providers also effectively act as institutions of certification. At present, global green bond indices are compiled by Bank of America Merrill Lynch, Barclays MSCI, Standard & Poor's and Solactive.[6] Each

[6] In addition, there are several internationally listed green bond indices focusing on specific jurisdictions – in particular China. For instance, the Shanghai Green Bond Index Series (developed by

has its own methodology for choosing the components of the index. While advertising consistency with the Green Bond Principles, each index also specifies additional factors such as size and liquidity, as well as the specific industry sectors for which the proceeds are used.

Index providers can arguably serve an ongoing monitoring function, since they can discard entities from an index as well as include them. However, since many inclusion criteria for green bond indices are much less concrete than those for conventional bonds (such as minimum levels of market liquidity and credit ratings), it remains to be seen whether the index providers can monitor such environmental criteria on a continuous basis.

External reviews

Though it is not a part of the four main Green Bond Principles, it was recommended in the 2015 edition of the Principles that green bond issuers "use external assurance to confirm alignment with the key features of Green Bonds". This can include second opinions and verifications. From 2016, the Principles referred to "external reviews" rather than "external assurance", while the list of recommended external reviews was expanded to include those provided by rating agencies (ICMA (2016)).

A limitation of the CBI standard and inclusion in the green bond indices is their binary nature: a bond is either green or not. More granular assessments could contain valuable information for investors, such as the degree of environmental benefits, or whether environmental benefits are likely to persist. Indeed, the following providers of green certification make more granular assessments.

CICERO is a climate research institute based in Oslo (Table 1, third column) and the leading provider of second opinions. It evaluates the issuer's framework for both project selection and investment (CICERO (2016)). CICERO provides three different degrees of positive assessment ("shades of green"), reflecting the bond's adherence to a long-term vision for a low-carbon, "environmentally resilient" society. However, CICERO reviews the green bond framework at the time of issuance. Ex post changes in the framework or environmental impact are not monitored, unless the issuer specifically requests it.[7]

Moody's Green Bond Assessments. The first public methodology for the assessment of green bonds by a ratings agency was published by Moody's Investors Service in March 2016 (Table 2, second column). Green Bond Assessments (GBAs) are intended to "assess the relative likelihood that bond proceeds will be invested to support environmentally friendly projects", in line with the Green Bond Principles (Table 2, first column). As with their credit rating products, Moody's employs numerous quantifiable factors in determining the GBAs, with the explicit aim of

the Shanghai Stock Exchange in collaboration with China Securities Index Co), or the CUFE-CNI Green Bond Index Series (developed by the Shenzhen Securities Information Co together with the International Institute of Green Finance) are indices based on green bonds issued in China which are also listed in Europe on the Luxembourg stock exchange.

[7] More regular monitoring is now implicitly recommended by the Green Bond Principles though not necessarily delegated to third parties. In 2016, the Principles were updated to state that issuers should "... keep readily available up to date information on the use of proceeds to be renewed annually until full allocation and as necessary thereafter in the event of new developments".

Comparison of Green Bond Principles and rating agencies' green certifications — Table 2

Green Bond Principles	Moody's Green Bond Assessments	Standard & Poor's Green Evaluations[1]
Use of proceeds Use should be described and present clear environmentally sustainable benefits.	*Use of proceeds* Assessment depends on percentage of proceeds allocated to eligible project categories. Weighted 40% as a factor.	*Mitigation* Assesses the environmental impact of financing proceeds over the life of the assets. Weighted 60% as a factor.
Process for project evaluation and selection Decision-making process should be outlined; in particular, how projects fit into green categories, eligibility criteria and environmental sustainability objectives.	*Organisation* Sub-factors: effectiveness of environmental governance and organisation structure; rigorous review and decision-making process; qualified personnel and/or reliance on third parties; explicit criteria for investment selection; external evaluations for decision-making. Weighted 15% as a factor.	*Governance* Considers whether well defined procedures in place for: - Selecting projects eligible to be financed - Appraising and managing environmental impact - Complying with environmental regulations Weighted 19% as a factor.
Management of proceeds Net proceeds should be tracked by formal internal process.	*Management of proceeds* Sub-factors: segregation and tracking of proceeds on accounting basis; tracking of the application of proceeds by environmental category and project type; reconciliation of planned investments against allocations; eligibility rules for investment cash balances; external or independent internal audit. Weighted 15% as a factor.	*Governance* Considers whether well defined procedures in place for preventing proceeds of the bond from being used for other purposes than the intended green financings. Weighted 6% as a factor.
Reporting Issuers should provide annual list of projects to which proceeds are allocated.	*Disclosure on use of proceeds* Sub-factors: description of green projects; adequacy of funding to complete projects; quantitative descriptions of targeted environmental results; methods and criteria for calculating performance against targets; reliance on external assurances. Weighted 10% as a factor. *Ongoing reporting and disclosure* Sub-factors: reporting and disclosure post-issuance; ongoing annual reporting; granular detail on nature of investment and environmental impact; quantitative assessment of impacts to date; comparison of assessments of impacts with projections at time of issuance. Weighted 20% as a factor.	*Transparency* - Use of proceeds reporting - Impact reporting and disclosure - External verification of impact data Weighted 15% as a factor.

[1] The methodology of Standard & Poor's Green Evaluations differs between instruments that finance mitigation projects and those that finance adaptation projects. The comparison of the table focuses only on the evaluations of instruments that finance mitigation projects, or those that "bring environmental benefits and target areas such as natural resources depletion, loss of biodiversity, pollution control, and climate change".

Sources: International Capital Market Association (2015); Moody's Investors Service (2016a); Standard & Poor's (2017b).

increasing their transparency and replicability. Regular review is anticipated, similar to the way regular credit ratings are refreshed over a multi-year horizon.[8]

Standard & Poor's Green Evaluations. Standard & Poor's introduced Green Evaluations in 2017 (Table 2, third column). The focus of these ratings is broader than that of GBAs, as they include a technical environmental impact assessment component, along with governance and transparency components. A score between zero and 100 is intended to evaluate the relative ranking of the overall expected lifetime environmental impact relative to maintaining the status quo – after discounting for qualities of the governance and transparency of the bond's use of proceeds.

Notwithstanding its broader focus, the S&P methodology can also be viewed as mostly in line with the Green Bond Principles, while providing transparency with regard to the quantitative importance of various factors, and considerable granularity in the final assessment. That said, each score is a point-in-time evaluation, and is removed from the S&P website after at most 18 months. In this sense, ex post assessment is not provided unless requested as part of a separate evaluation.

The pricing of green bonds, financial performance and risks

For the green bond market to channel a significant amount of funds into environmentally friendly projects, green bonds should also fulfil the needs of both issuers and investors. Looking at the same issuer, the risk characteristics of a green bond are essentially identical to those of a conventional bond: while the proceeds from the issuance of a green bond are earmarked for environmentally friendly projects, green bonds are serviced from the cash flows of the entire operations of the issuer – not just the green project.

These characteristics have implications for the pricing of green bonds and their attractiveness for investors. A premium at issuance over comparable bonds without a green label would indicate that a significant number of investors value the label, enough to give issuers an extra incentive to issue bonds that have it. At the same time, these investors will still be interested in an acceptable financial performance of green bonds over time. Another consideration is the exposure to credit risks related to environmental change. That green bonds support environmentally beneficial projects does not necessarily imply lower exposure to such risks. The rest of this section discusses these issues further.

The green bond premium

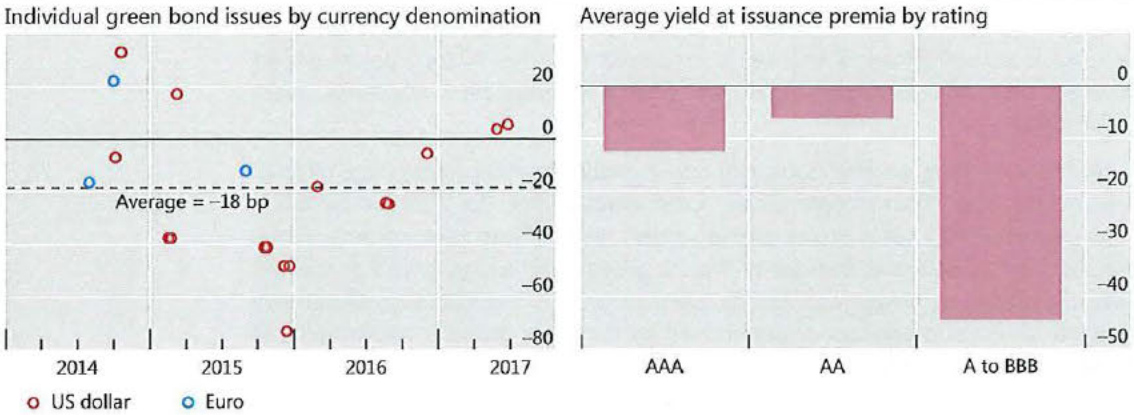
Does the green label influence the price that issuers are willing to pay (in other words, the yield spread over risk-free rates that they are willing to accept) for a bond? A large body of literature documents that factors unrelated to credit risks can significantly

[8] ESG ratings, which assess a firm's performance across a weighted average of environmental, social and governance (ESG) issues, provide many of the same attributes. In June 2016, the Green Bond Principles statement by ICMA recognised that the "use of proceeds" bond concept might be applied to themes beyond the environment, such as bonds financing projects with social objectives, or with a combination of social and environmental objectives. However, the green bond label is still reserved for investment projects providing clear environmental benefits. Since ESG ratings are not specifically focused on environmental benefits, they are not considered in this feature.

Credit spreads at issuance of green versus non-green bonds[1]

In basis points

Graph 3



[1] Relative differences in credit spreads at issuance compared with a non-green bond of the same issuer at the closest possible date. The average closest date of a non-green bond issue by the same issuer is around seven days before the issue date of the green bond. Sample was restricted to pari passu bonds of at least two-year maturity at issuance, at least $10 million issuance amount and currency of denomination being either euros or US dollars. Credit spreads are calculated as the spreads of yields at issuance over the yield curve of US Treasury securities (for US dollar-denominated bonds) and German Federal Treasury securities (for euro-denominated bonds) of the same maturity at issuance date; if the same maturity was not available, the available points of the respective yield curve were interpolated.

Sources: Board of Governors of the Federal Reserve System; Deutsche Bundesbank; Bloomberg; authors' calculations.

influence bond yield spreads, such as specific demand and supply factors (eg Collin-Dufresne et al (2001), Greenwood and Vayanos (2014)) or liquidity premia (eg Longstaff (2004), Amihud et al (2006)). If a sizeable population of investors is willing to pay a premium (accept a lower spread) for green bonds, this should show up in the pricing of the bonds at issuance.

To analyse the price effect of the green label, we compare the credit spreads at issuance of a cross-section of 21 green bonds issued between 2014 and 2017 with the credit spreads at issuance of conventional bonds of the same issuers at the closest possible issue date (Graph 3). As most issuers of green bonds also regularly issue conventional bonds, this comparison allows us to control for issuer-specific idiosyncratic factors, including credit risk. We do not include any project bonds, as claims on cash flows could possibly be on different projects with different risk characteristics. We further restrict the sample to pari passu fixed rate bonds, to avoid the influence that debt seniority or the uncertainty of floating rates could have on the pricing at issuance. We look for conventional bonds of roughly the same maturity, and restrict our matched pairs to US dollar- and euro-denominated green bonds, as spreads over local benchmark rates tend not to be as stable for bonds issued in EME currencies.

Our results indicate that green bond issuers *on average* have borrowed at lower spreads than they have through conventional bonds. This confirms the results from other recent studies (eg Zerbib (2017), Barclays (2015)). The mean difference in spread in our sample is around 18 basis points.[9] Overall, this is consistent with a high

[9] An 18 basis point lower credit spread would be significant relative to the potential costs of a green label or rating. The certification fee for the green label of the Climate Bonds Initiative is a flat 0.1 basis points of the issue value (though the CBI also requires the external engagement of a party that verifies

demand for green bonds (CBI (2017), OECD (2016)) relative to supply – in other words, enough investors have a preference for holding green bonds to influence the issue price. When we segment the sample by rating category, it appears that the green yield difference is greater for riskier borrowers (Graph 3, right-hand panel). Recall that we compare credit spreads at issuance of pari passu bonds from the same issuer, so this result does not reflect differences in credit risk (or other factors) across issuers within the same rating category. Again, this finding is consistent with previous work (Zerbib (2017)).

At the same time, we also document considerable variation across the individual green bond issues in our sample (Graph 3, left-hand panel). The standard deviation of the premium is 27 basis points. Not all issuers were able to take advantage of a yield discount at issuance: five out of the 21 green bond issues priced at spreads above the matched conventional bonds. We also could not document yield premia for higher levels of greenness as determined by the more granular assessments of the major rating agencies.[10]

Financial performance over time

Returns to investors from green bonds will reflect their performance over time, in particular when investors do not intend to simply hold them until maturity. The average premium at issuance will not necessarily translate into a noticeable underperformance in secondary market trading. Investors in the secondary market may well price in a different premium from primary market investors.[11] Many investors will also be interested in the realised volatility of green bonds as a metric of financial performance.

Green bond indices are a good starting point to analyse the secondary market performance of green bonds from an investor perspective. Green bond indices contain a diversified broader portfolio of bonds[12] and thereby provide a good means of comparison with the performance of other bond indices that are suitable for a wide range of investors. We analyse so-called hedged returns, which measure returns in US dollars that can be achieved by hedging the currency exposures of the underlying index. As green bond indices differ notably from other global bond indices in their currency composition, currency movements alone can have an outsize impact on relative returns.

procedures and reports). As for the green assessments of the major rating agencies, even if they were to be as expensive as a normal credit rating (3–5 basis points of the issue volume (White (2002))), the costs would be far less than 18 basis points.

[10] These new assessments have so far tended to be at one end of the spectrum: for instance, the 26 bond issues with Moody's GBAs as of end-July 2017 were all at the highest level (GB1). The 10 available bond issues with green rating evaluations by Standard & Poor's rank between 67 and 92 (out of 100), but the only four of these bonds for which we could find yields are from the same issuer and therefore have the same score. This does not allow us to make meaningful comparisons of the pricing of bonds across different green bond ratings. Likewise, because of a paucity of yield data, we cannot compare the impact of the rating agency assessments with those of the other green labels.

[11] Buy and hold investors will have decided ex ante that the benefits of holding the individual issue to maturity equal or outweigh the premium.

[12] Some analysts, however, have argued that green bond indices are less diversified than other much broader bond indices (Fitch Ratings (2017)). Nevertheless, the green bond indices we consider represent an accurate overall picture of the financial characteristics of the green bond market at its current stage of development.

Green bond indices: return characteristics

Annualised monthly total returns, July 2014–June 2017; in per cent

Table 3

		Hedged returns[1]				Unhedged returns[2]			
		Cumulative over 36 months	Mean (1)	Std dev (2)	Sharpe ratio = (1)/(2)	Cumulative over 36 months	Mean (1)	Std dev (2)	Sharpe ratio = (1)/(2)
Green bond indices	Standard & Poor's	.	.	.	.	–4.18	–1.48	18.44	–0.08
	BofA Merrill Lynch	9.17	3.06	8.64	0.35	–6.45	–2.15	18.92	–0.11
	Solactive	.	.	.	.	–4.52	–1.51	18.66	–0.08
	Barclays MSCI	10.23	3.41	9.61	0.35	–3.43	–1.14	17.23	–0.07
Global bond indices	Broad-based	11.26	3.75	11.64	0.32	3.46	1.15	14.97	0.08
	AA average rating	10.29	3.43	10.21	0.34	0.97	0.32	14.16	0.02
	A average rating	11.02	3.67	10.99	0.33	3.12	1.04	14.08	0.07

[1] Total returns for indices hedged against currency risks, which are more comparable across indices that differ in their currency composition. They represent a close estimation of the return that can be achieved by hedging the currency exposures of the underlying index by selling foreign currency forwards at one-month forward rates. Hedged returns are not exact measures of the true returns, since they do not include transaction costs for hedging contracts. Those can be considered small, in particular, since euro exposures present the largest foreign currency component (see also Graph 1). Bid-ask spreads on EUR/USD forwards, which are an indicator of transaction costs, are usually between 1 and 1.5 bp. [2] Total returns from holding a simple position in the respective index. Green bond indices differ substantially in their currency composition from the global bond indices. Hence, currency movements will significantly affect return differentials between green bond and global bond indices.

Sources: Bloomberg; Barclays; authors' calculations.

Overall, the performance of *hedged* green bond indices has been similar to that of global bond indices of comparable credit rating composition[13] (Table 3, left-hand columns). Even though the available green bond indices by Bank of America Merrill Lynch, Barclays MSCI, Standard & Poor's and Solactive diverge slightly in their composition (CBI (2015)), their return characteristics hardly differ. The ratio of average monthly hedged returns to their standard deviation (Sharpe ratio), which is a standard measure for risk-adjusted performance, was in some cases even slightly higher for green bond indices than for global bond indices, though that difference was not statistically significant.

Total returns in US dollars on *unhedged* green bond indices, however, have exhibited higher volatility than those of broad-based bond indices (Table 3, right-hand columns). As the currency composition of the green bond indices is very diverse, and much less tilted towards the US dollar than is the case for global indices, movements in the currency of denomination of some green bonds in the indices increase the measured return volatility. This points to the importance of the availability of currency hedges for investors in green bonds.[14]

[13] The universe of labelled green bonds from Bloomberg and CBI has an average rating of slightly below AA. The average maturity and duration of the global bond indices and the different green bond indices are quite similar, but sectoral and currency compositions differ.

[14] Importantly, some researchers (eg Andersson et al (2016)) have shown that it is possible to construct a portfolio of green instruments that has an identical performance to that of a broader market index. This would provide a product for a wide range of green investor that yields a financial performance equal to that of a diversified market portfolio, but with environmental benefits.

The green label and exposure to environmental risks

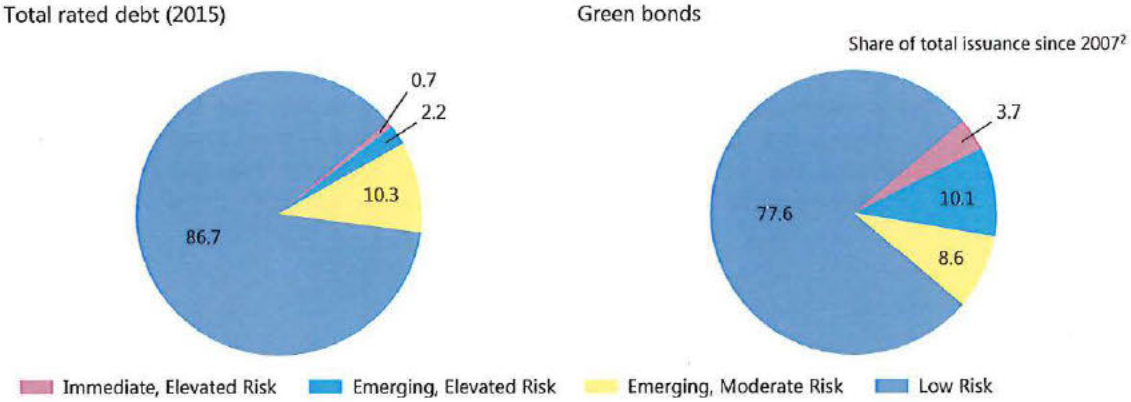
Carney (2015) describes the potentially severe impact of climate change on the economy as a "tragedy of the horizon": investors and other actors do not sufficiently take the risks into account as they materialise only over a long horizon. Indeed, a number of academic studies have documented a tendency for investors to inadequately price environmental risks (Hong et al (2016) and references therein). This is despite already strong evidence of severe financial impacts of both *physical risks,* due to climate-related events such as droughts and floods, and *transition risks,* such as the risk of a material change in environmental regulations (Caldecott et al (2014)). For instance, rating agencies now plan to take account of the financial risks related to the transition to stricter carbon emission rules implied by the Paris agreement when they analyse credit risks of bond issuers from polluting sectors (eg Moody's Investors Service (2016b)).

One question is whether green bonds can provide an instrument for investors to hedge against these environmentally related financial risks. If these risks materialise, bonds from issuers in polluting sectors may be subject to significant revaluations. To the extent that issuers of green bonds are better shielded against large revaluations, they could serve as an efficient risk management instrument.

But this need not be the case. Green bonds generally comprise investor claims on an entity's overall operations. A large and diversified energy company may invest a considerable amount in green projects, but other parts of its business (for instance coal power plants) may expose it to environmentally related credit risks, such as changes in carbon regulations. There may also be green bonds whose income stream is vulnerable to climate change quite apart from transition risk (for example, wind farms subject to flood risk). In the case of almost all green bonds, the exposure to environmentally related credit risks is a function of the entire company's business. Only a few green bonds are project bonds, where claims are on the cash flows of the financed green project itself.

Environmental credit risk composition of all rated bonds versus green bonds only[1]

In per cent — Graph 4



[1] Aggregate issuance of bonds by issuers from sectors which belong to the risk categories shown, as defined by Moody's. See Moody's Investors Service (2015). In cases where industrial classification is ambiguous, we use equal weights to distribute the issuance volume across relevant sectors. [2] Through mid-June 2017.

Sources: Bloomberg; Climate Bonds Initiative; Moody's; authors' calculations.

Indeed, the evidence suggests that green bonds are more, not less, exposed to environmentally related credit risks. Moody's provides a classification of credit exposures to environmental risks at the sectoral level (Moody's Investors Service (2015) and Annex Table A1).[15] Within the universe of corporate debt rated by Moody's, 13.2% is issued by institutions in industries with moderate or greater exposure to environmental credit risk, and around 2.9% in industries classified as either immediate or emerging elevated risk (Graph 4, left-hand panel). By contrast, when we examine the industry composition of green bonds alone, we see that 22.4% of green bonds are issued in sectors with moderate or greater exposure to environmental credit risk, and nearly 14% in industries classified as elevated risk (right-hand panel). Thus, the percentage of green bonds in high-risk sectors exceeds that for overall rated debt by a factor of four.

Conclusion

Green bond principles and standards are an important step towards promoting green finance. Since the introduction of the Green Bond Principles by the ICMA in January 2014, the issuance of labelled green bonds has increased rapidly, with a growing number of issuers from the private sector and EMEs. Several green bond indices have also been introduced, allowing a broader group of investors to take a diversified position in green bonds. The evidence suggests that investors place value on the green label at issuance, even though the post-issuance financial performance of green bonds is comparable with that of conventional bonds. However, for this still relatively small market to grow more, several further developments need to take place.

First, the various existing definitions and labels for green bonds pose a challenge for investors, who may benefit from more consistent standards. The ongoing work to improve the consistency of standards in China and the European Union are promising in this regard. At the same time, more ongoing monitoring by "second opinion" providers, rating agencies or other forms of continuous third-party verification may be needed. Even if asset managers utilise the green label simply to signal to ultimate investors their fulfilment of green mandates, the information value of those labels can depreciate over time as technology evolves or policies of the issuer change.

A second informational aspect that is not covered by current green certification schemes is the environmentally related financial risks of green bonds. While the management of environmental risks extends far beyond green bonds, it is important to avoid the misperception that green bonds are insulated from such risks. In fact, among all rated bonds, those with a green label are more likely to be in sectors that are exposed to such risks. Green bond standards could be enhanced to highlight the degree of financial risks stemming from environmental factors so as to further encourage investors to manage these risks effectively.

[15] Credit risks from environmental exposures are defined as the risks to a borrower's ability to repay caused by physical climate events or changes in environmental regulations.

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Annex

Moody's sectoral environmental risk classification

Credit exposure to environmental risks

Table A1

Environmental risk classification	Description	Relevant industry examples
Immediate, Elevated Risk	Sectors are already experiencing material credit implications as a result of environmental risk. Rating changes have either already been occurring for a substantial number of issuers or ratings changes are likely within the next three years.	Unregulated utilities and power companies.
Emerging, Elevated Risk	Sectors overall have clear exposure to environmental risks that, in aggregate, could be material to credit quality over the medium term (three to five years), but are less likely in the next three years.	Automobile manufacturers, power generation projects.
Emerging, Moderate Risk	Sectors have a clear exposure to environmental risks that could be material to credit quality in the medium to long term (five or more years) for a substantial number of issuers. However, it is less certain that the identified risks will develop in a way that is material to ratings for most issuers.	Regulated electric and gas utilities with generation, sovereigns – developing countries, environmental services and waste management, paper and forest products.
Low Risk	Sectors in this category have either no sector-wide exposure to meaningful environmental risks or, if they do, the consequences are not so likely to be material to credit quality.	Supranationals and sovereigns – developed countries, banks and finance companies, consumer goods, semiconductors and technology hardware.

Source: Moody's Investors Service (2015).

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July 2, 2020

VIA ELECTRONIC DELIVERY

Diane Hanian
Commission Secretary
Idaho Public Utilities Commission
11331 W Chinden Blvd.
Building 8 Suite 201A
Boise, ID 83714

Re: Case No. PAC-E-20-03
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES IN IDAHO AND APPROVAL OF PROPOSED ELECTRIC SERVICE SCHEDULES AND REGULATIONS

Dear Ms. Hanian:

Please find enclosed for electronic filing Rocky Mountain Power's Application in the above-referenced matter along with a Stipulation provided as Attachment 1 to postpone the general rate case and request Commission authorization for: 1) an accounting order authorizing the Company to create a regulatory asset to transfer the decommissioning and plant closure costs of Cholla Unit No. 4 ("Unit 4") when it is retired; 2) approval of modifications to Phase II of the settlement stipulation to implement tax reform ("the Tax Stipulation");[1] and 3) approval of ratemaking treatment for Pryor Mountain and Foote Creek I wind resources to match costs with benefits, with cost recovery capped at the level of benefits until the prudence of the resources can be determined in the next general rate case. Work papers supporting the Excess Deferred Income Tax balances are also included.

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at (801) 220-2963.

[1] *In the Matter of the Investigation into the Impact of Federal Tax Code Revisions on Utility Costs and Ratemaking, Case No. GNR-U-18-01, Final Order No. 34431 (May 3, 2019).*

Very truly yours,

Joelle Steward
Vice President, Regulation

Enclosures
CC:
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES IN IDAHO AND APPROVAL OF PROPOSED ELECTRIC SERVICE SCHEDULES AND REGULATIONS	**CASE NO. PAC-E-20-03** **APPLICATION OF ROCKY MOUNTIAN POWER**

Rocky Mountain Power, a division of PacifiCorp, ("Rocky Mountain Power" or the "Company"), hereby applies to the Idaho Public Utilities Commission ("Commission") for: 1) an accounting order authorizing the Company to create a regulatory asset to transfer the decommissioning and plant closure costs of Cholla Unit No. 4 ("Unit 4") when it is retired; 2) approval of modifications to Phase II of the settlement stipulation to implement tax reform ("the Tax Stipulation");[1] and 3) approval of ratemaking treatment for Pryor Mountain and

[1] *In the Matter of the Investigation into the Impact of Federal Tax Code Revisions on Utility Costs and Ratemaking, Case No. GNR-U-18-01, Final Order No. 34431 (May 3, 2019).*

Foote Creek I wind resources to match costs with benefits, with cost recovery capped at the level of benefits until the prudence of the resources can be determined in the next general rate case.

In support of this Application, Rocky Mountain Power states as follows:

I. INTRODUCTION

1. Rocky Mountain Power is authorized to do and is doing business in the state of Idaho. The Company provides retail electric service to approximately 84,000 customers in the state of Idaho and is subject to the jurisdiction of the Commission.

2. Rocky Mountain Power files this application pursuant to Idaho Code §61-524 and RP 52, which authorizes the Commission to prescribe the accounting to be used by public utilities subject to its jurisdiction.

II. COMMUNICATIONS

3. Communications regarding this Application should be addressed to:

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1407 W North Temple, Suite 320
Salt Lake City, Utah 84116
E-mail: emily.wegener@pacificorp.com

In addition, Rocky Mountain Power requests that all data requests regarding this application be addressed to:

By email (preferred)	datarequest@pacificorp.com
By regular mail	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

Informal inquiries related to this application may be directed to Ted Weston, (801) 220-2963.

III. CASE NO. PAC-E-20-03 SETTLEMENT TERMS

4. On March 26, 2020, pursuant to Idaho Public Utilities Commission Rule of Procedure 122, the Company filed a Notice of Intent to file a General Rate Case with the Commission. Recognizing the impact that the COVID-19 pandemic has on its customers and knowing a rate increase at this time in particular would be challenging for customers, the Company developed a rate plan that would allow it to delay filing a general rate case.

5. The Company, Commission staff, Bayer, Idaho Conservation League, Idaho Irrigation Pumper Association, and PacifiCorp Idaho Industrial Customers, the ("Parties") were able to reach an agreement to delay a general rate case so no change to general rates would be effective prior to January 1, 2022. In return for the Company agreeing to delay the rate case, the Parties agreed to support the Company's application to request Commission authorization for:

- A regulatory asset to transfer Cholla Unit 4 net book balance upon closure of the plant in December 2020. The regulatory asset will also include other closure-related and decommissioning costs.
- Modifications to the Phase II Settlement Stipulation in Case No. GNR-U-18-01, on the ratemaking treatment for the 2017 Tax Cut and Jobs Act ("TCJA"). The Company may propose that the remaining balance from

excess deferred income tax savings from the TCJA be retained to buy-down the Cholla Unit 4 and be deferred to offset the January 1, 2022 rate increase.

- Ratemaking treatment for the Pryor Mountain and Foote Creek I wind resource to match costs and benefits with a cost cap amount each year at the benefit level. The Company may propose to include these resources in the Resource Tracking Mechanism/Energy Cost Adjustment Mechanism ("RTM/ECAM"), consistent with the terms agreed to in Case No. PAC-E-17-07. Prudency will be determined during the next General Rate Case.
- There will be no change to the ECAM baseline NPC of $26.90/MWh (on a sales-basis) established in PAC-E-16-12, until the base is reset in the next general rate case.
- The Company will make its results of operations and cost of service models developed in anticipation of filing a rate case on June 1, 2020, available to parties and the Company will respond to the parties' reasonable data requests regarding the same.

6. The Company will provide the annual Results of Operations report and a Cost of Service study separately to the Parties. The Results of Operations will fulfil the requirements of Commission Order 29708 that requires the Company to file an Annual Earnings Report. On April 7, 2020, the Company notified the Commission of its intent to utilize the Results of Operations report from the rate case to meet this requirement. The agreement signed by the Parties is provided as Attachment 1 to the Application.

IV. CLOSURE OF CHOLLA UNIT NO. 4

7. The Cholla power plant consists of four units located near Joseph City, Arizona, with a combined generating capability of 995 megawatts ("MW"). Arizona Public Service Company ("APS") owns Cholla Units 1 and 3 (Unit 2 was retired in October 2015) and operates the entire Cholla facility. PacifiCorp owns approximately 37 percent of Cholla's common facilities and 100 percent of Unit 4, which was commissioned in 1981 with a generating capability of 395 MW.

8. In February 2011, the Arizona Department of Environmental Quality ("ADEQ") submitted a regional haze state implementation plan ("SIP") to the Environmental Protection Agency ("EPA"). The SIP submittal included a best available retrofit technology ("BART") analysis and determination for the need to install nitrogen oxides ("NOx") emission controls on Cholla Unit 4. In December 2012, EPA rejected the state's BART determination for NOx controls on the Cholla units and issued a federal implementation plan ("FIP") in place of the SIP. The EPA's FIP required installation of low-NOx burners ("LNB"), separated over-fire air ("SOFA"), and selective catalytic reduction ("SCR") systems for NOx control on the Cholla units by December 5, 2017.

9. In January of 2015, APS and PacifiCorp prepared and submitted a BART reassessment for the Cholla Units to ADEQ and requested that ADEQ revise its BART analysis due to the substantial costs associated with the compliance requirements of EPA's FIP. As part of the reassessment, APS and PacifiCorp committed to operate LNB and SOFA on Unit 4, and permanently cease burning coal in the Unit by April 30, 2025 (with an option to convert to natural gas combustion by July 31, 2025). In October 2015, ADEQ submitted a SIP revision

to EPA adopting the requirements of the BART reassessment, including the cease operations or convert requirement. EPA proposed approval of the SIP revision in July of 2016, and issued final approval in March of 2017.

10. Due to these environmental compliance rulings, PacifiCorp is required to cease operations at Cholla Unit 4 or convert it to natural gas by April 30, 2025. However, the Company's most recent IRPs have indicated that it was economic to pursue earlier retirement. On December 27, 2019, the Company announced its decision to retire Unit 4 by December 31, 2020. The Company's decision to initiate the process of retiring Unit 4 is supported by the economic analysis it conducted.

11. PacifiCorp's 2019 IRP preferred portfolio reflects customer benefits associated with Cholla Unit 4's retirement as early as 2020. Given the unique ownership structure at the Cholla plant, PacifiCorp's action plan committed to initiating the process of retiring Cholla Unit 4 and removing it from service no later than January 2023 and earlier if possible.

12. PacifiCorp has initiated the process of retiring Unit 4 and anticipates being able to achieve retirement by year-end 2020, earlier than the January 2023 timeframe initially set forth in the 2019 IRP action plan. Further economic analysis building on the IRP studies confirmed that early closure at the end of 2020 is expected to generate more present-value customer benefits relative to Unit 4 continuing operation through April 2025.

13. The IRP economic analysis relies on an assessment of system value which compares the outcomes of the Planning and Risk model ("PaR") scenarios with a simulation period covering the 2019 through 2025 timeframes. Consistent with the 2019 IRP preferred portfolio, the simulations utilize a range of natural gas price and carbon policy scenarios which

incorporate a CO_2 price beginning in 2025 (medium natural gas price and medium CO_2 price assumptions (the "MM" price-policy scenario); low natural gas price and no CO_2 price assumptions (the "LN" price-policy scenario), and high natural gas price and no CO_2 price assumptions (the "HN" price-policy scenario)).[2]

14. Each price-policy scenario was run twice: once to update the 2019 preferred portfolio where Cholla Unit 4 is assumed to retire at the end of December 2020, and the other assuming Unit 4 continues operation through the April 2025 timeframe. Each price-policy scenario showed an increase in net system costs when it was assumed that Unit 4 operated as a coal-fired facility through April 30, 2025.

15. The updated economic analysis confirmed PacifiCorp's ongoing IRP analyses and demonstrated that retirement of Unit 4 by year-end 2020 will produce net customer benefits relative to a case where Unit 4 continues operating through April 2025. This outcome is consistent across a range of price-policy scenarios. This holds true even with incremental costs, such as the closure-related costs, in part because PacifiCorp will no longer incur the operating costs associated with running Unit 4.

16. Early closure at the end of 2020 is expected to generate between $96 million and $123 million in present-value customer benefits relative to an alternative where Unit 4 continues to operate through April 2025. All three price-policy scenarios report an increase in

[2] For both PaR runs produced under the MM price-policy scenario, price assumptions were developed from PacifiCorp's September 2019 official forward price curve. LN and HN price-policy scenarios are derived from third-party sources. Natural gas prices in the LN price-policy scenario do not drop below prices in the MM scenario until 2026-beyond the early retirement study period. Consequently, the primary difference between the MM and LN price-policy scenario is the absence of a CO_2 price in 2025 in the LN scenario.

net system costs when it is assumed that Unit 4 operates as a coal-fired facility through April 30, 2025, relative to the case where it is assumed to retire at the end of 2020. Attachment 2 to this application summarizes the results of each of these price-policy scenarios.

17. Early retirement of Cholla Unit 4 will increase costs in 2020, followed by decreased costs between 2021 and 2025. The 2020 cost increases are primarily associated with early termination payments of a safe harbor lease. PacifiCorp is the legal owner of Cholla Unit 4, but for income tax purposes only, PacifiCorp is treated as leasing portions of Unit 4 that are subject to a safe harbor lease. With the early retirement, certain payments may be required to be made by PacifiCorp to the tax lessor. The Company has estimated the high range of a potential payment at approximately $3.3 million.

18. When PacifiCorp acquired Cholla Unit 4, the Company paid APS prepaid availability and transmission charges in April 1994 and April 1996. The charges are related to the construction of transmission facilities that enable an additional 150 MW of northbound firm transmission capability on the Phoenix-Mead transmission line. The prepaid transmission service cost began amortization over a fifty-year life in May 1997, and PacifiCorp began receiving transmission credits on its bill from APS. Under the early retirement case, it is assumed the unamortized balance would be written off.

19. Early retirement of Unit 4 by December 2020 will reduce net system costs through the assumed April 2025 retirement date. Over this period, projected generation from Unit 4 declines, and the value of energy net of fuel costs is insufficient to offset annual fixed operating costs.

20. As of December 31, 2020, Unit 4's net book value is expected to be

approximately $284 million. Because the Company anticipated filing a general rate case with rates effective January 1, 2020, Cholla Unit 4 was removed from the 2018 Depreciation study. If the Commission approves the 2018 Depreciation stipulation depreciation of Cholla will end December 31, 2020. However, current rates include approximately $0.9 million in annual depreciation expense. The Company provided an offset to the regulatory asset balance by that amount to account for one additional year during 2021 of Cholla depreciation expense in Idaho rates.

21. The Company anticipates retiring Unit 4 by December 31, 2020, and requests Commission approval to use tax benefits to buy-down the net plant balance as explained below and transfer the remaining balances for Cholla Unit 4 from the respective FERC accounts and record a regulatory asset in FERC account 182.3 (Other Regulatory Assets) on the date the plant is removed from service. Idaho's share of the regulatory asset will be established based on the system generation ("SG") allocation factor for the calendar year 2019. Table 1 summarizes the estimated plant balances as of December 31, 2020.

TABLE 1

Cholla Unit #4 Retirement - December 31, 2020 Estimated Balances				
Description	**Total Company**		**Idaho Allocated**	
Gross EPIS	$	552.7	$	32.7
Accumulated Depreciation	$	(268.4)	$	(15.9)
CWIP	$	1.8	$	0.1
M&S	$	6.1	$	0.4
Liquidated damages	$	19.6	$	1.2
GE safe harbor lease termination payment	$	3.3	$	0.2
Savings due to O&M Expense	$	(27.3)	$	(1.6)
Savings due to Depreciation Expense	$	(15.2)	$	(0.9)
Estimated Decommissioning Costs	$	47.3	$	2.8
Estimated December 31, 2020 Balances	**$**	**319.9**	**$**	**18.9**

22. Since Cholla Unit 4 was not included in the 2018 depreciation rates not only will plant balances stop being depreciated, recovery of estimated decommissioning costs will also stop. The Company currently estimates the cost of decommissioning Cholla Unit 4 and remediating the site to be approximately $47 million. The Cholla plant is operated by APS so the Company isn't certain when the plant will be retired and decommissioned.

23. As further discussed below the Company recommends using some of the available Excess Deferred Income Tax ("EDIT") benefits to buy-down or offset the Cholla Unit No. 4 unrecovered plant balances and closure costs to mitigate future rate impact to Idaho customers.

V. MODIFICATION OF FEDERAL TAX REFORM ACT SETTLEMENT

24. On March 5, 2019, the Company filed an all-party stipulation with the Commission resolving how the tax savings from the federal "act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018" (the "Tax Reform Act") for the period of 2018 through 2020 would be returned to customers.[3]

25. Parties to the Tax Stipulation agreed to the ratemaking treatment for the deferred balances associated with the tax savings arising from the Tax Reform Act, which included refunding certain tax savings through the ECAM and offsetting the 2013 incremental depreciation expense with some of those tax savings. The Order approved the $1,141,000 deferred balance of current tax savings for the period of January 1, 2018, through May 31, 2019, that had not been returned to customers through Schedule 197. This balance was tracked and amortized over two years ($570,500 per year), beginning June 1, 2019,

[3] *In the Matter of the Investigation into the impact of Federal Tax Code Revisions on Utility Costs and Ratemaking,* Case No. GNR-U-18-01, Order No. 34331 (May 3, 2019).

through the ECAM.

26. The Tax Reform Act resulted in Idaho-allocated EDIT composed of the following amounts, grossed-up for taxes: 1) Protected property-related EDIT of $105,924,604[4], with estimated annual amortizations through the average rate assumption method ("ARAM") of $2,564,410 in 2018, $2,352,309 in 2019, and $2,306,632 in 2020; and Non-protected property and non-property EDIT of $14,883,505.[5]

27. During 2019 the Company determined that it was necessary to use a different method to amortize the protected EDIT balances. The Tax Stipulation was based on the ARAM, but on further review the Company determined that it didn't have the necessary records to support that accounting method and had to switch to the Reverse South Georgia Method ("RSGM"). The RSGM did not change the balances available but it did modify the annual amortization of those balances as compared to the ARAM.

28. The Tax Stipulation included an estimate of the annual protected property EDIT in the amount of $2,564,364 for 2018, $2,352,309 for 2019 and $2,306,632 for 2020, less the associated rate base offset, that would be refunded to retail customers through a cents per kilowatt-hour credit netted against the ECAM rate.

29. Lastly, the Tax Stipulation provided that the non-protected and non-property EDIT, arising from the Tax Reform Act would be amortized over seven years, approximately $2,126,215 annually less the rate base offset, and used to offset the 2013 incremental depreciation expense through the ECAM, not subject to the sharing band and until the rate

[4] The protected property EDIT is $79,881,345, or $105,924,604 grossed up for taxes.
[5] The non-protected property EDIT is $10,009,386, or $13,272,689 grossed up for taxes, and non-protected non-property total EDIT is $1,214,771, or $1,610,816 grossed up for taxes.

effective date in the next general rate case.

30. In the Tax Stipulation the parties agreed they could propose to change the seven-year amortization period for the unamortized portion of the non-protected property and non-property EDIT balance in the next Idaho general rate case. In the agreement with parties to not file a general rate case in 2020, parties agreed the Company could propose modifications to the Tax Stipulation outside of a general rate case.[6]

31. Under the RSGM protected-property EDIT was $4,571,790 for 2018 and $4,602,855 for 2019, increasing the Tax Savings amortization of protected-property EDIT by $4,257,972 over the two-year period. The Company also identified the need to reclassify EDIT between protected property and non-protected and transferred $2,964,471 from the protected property to the non-protected EDIT balance which increased the unamortized balance to $17,847,973 for non-protected EDIT benefits.

32. Combining the increased amortization of protected property under the RSGM for 2018 and 2019 with the 2020 EDIT amortization that hasn't been returned to customers and the unamortized non-protected EDIT balance produces a total EDIT balance available to customers of $24,305,381. Table 2 is a summary of the EDIT savings available to customers. Work papers supporting these amounts are provided with the Application.

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[6] *See* Attachment 1.

Table 2

Tax Reform Act Benefits	2018	2019	2020	Total
Protected EDIT Deferral - RSGM	$ (4,571,790)	$ (4,602,855)	$ (6,451,861)	$(15,626,506)
Protected EDIT Deferral - ARAM	$ 2,564,364	$ 2,352,309		$ 4,916,673
	$ (2,007,426)	$ (2,250,546)	$ (6,451,861)	$(10,709,833)
Non-Protected EDIT - Estimate				$(14,883,504)
Amortization	$ 2,126,215	$ 2,126,215		$ 4,252,430
Non-Protected EDIT - Reclassification				$ (2,964,474)
Balance December 31, 2020				$(13,595,548)
Tax Reform Act Benefits Available December 31, 2020				**$(24,305,381)**

33. The Company requests authorization to use approximately $15.9 million of the $24.3 million EDIT Tax Reform Act benefits to pay off the Cholla Unit No. 4 unrecovered balances. The Cholla regulatory asset will be used to transfer the GE Safe Harbor lease payment and track actual decommissioning costs. The Company also requests authorization to cease the refund of tax savings in the ECAM filing in 2021 in order to use any remaining EDIT savings as of December 31, 2021 to mitigate the rate impact from the 2021 general rate case. As of December 31, 2020 this results in approximately $8.4 million in deferred Tax Reform Act benefits available to use to offset the next general rate case increase. The current refund of $7.6 million in current tax savings on Schedule 197 would continue until new rates are effective from the next general rate case.

34. The Company's decision to retire Cholla Unit 4 and use EDIT Tax Reform Act benefits to buy-down the remaining plant balance accelerates the availability of Idaho-allocated Cholla EDIT benefits as reflected in the 2020 Protected EDIT Deferral amount. Table 3 summarizes the items the Tax Benefit buy-down would be used for and the items tracked in the regulatory asset.

TABLE 3

Cholla Unit #4 Tax Buy-Down / Regulatory Asset				
Description	**Total Company**		**Idaho Allocated**	
Gross EPIS	$	552.7	$	32.7
Accumulated Depreciation	$	(268.4)	$	(15.9)
CWIP	$	1.8	$	0.1
M&S	$	6.1	$	0.4
Liquidated damages	$	19.6	$	1.2
Savings due to O&M Expense	$	(27.3)	$	(1.6)
Savings due to Depreciation Expense	$	(15.2)	$	(0.9)
Estimated Tax Benefit Buy-Down	**$**	**269.3**	**$**	**15.9**
Transferred to Regulatory Asset				
GE safe harbor lease termination payment	$	3.3	$	0.2
Estimated Decommissioning Costs	$	47.3	$	2.8
Estimated Regulatory Asset Balance	**$**	**50.6**	**$**	**3.0**

VI. RATEMAKING FOR PRYOR MOUNTAIN AND FOOTE CREEK I

35. The Company requests the Pryor Mountain and Foote Creek I wind resources be included in the RTM authorized by the Commission for other Company wind projects in Order No. 34104 to match the costs with the benefits these resources produce for customers.[7] Consistent with the stipulation[8] for ratemaking treatment approved in that proceeding, the costs would be capped at the benefit levels passed back through the ECAM so customers would not see a net cost for these projects through the RTM or ECAM. Net costs, if any, would be deferred for later recovery to be determined in the next general rate case when a full prudence

[7] *In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity and Binding Ratemaking Treatment for new Wind and Transmission Facilities.* Case No. PAC-E-17-07, Order No. 34104 (July 20, 2018).

[8] *The Stipulating Parties agree that the Company will maintain a cap on the annual total cost of the Stipulated Projects not to exceed the annual project benefits in the ECAM and RTM. Costs that are passed on to customers through the RTM, before the next general rate case, will be capped at the level of benefits that will flow through the ECAM, as such, on a combined basis, the ECAM and the RTM will not result in a net cost to customers associated with the Stipulated Projects. Any costs above this cap will be deferred as a regulatory asset for recovery to be set in the next general rate case.* Case No. PAC-E-17-07, paragraph 14 of the Stipulation.

review for these resources is expected to occur.

36. The Pryor Mountain Wind Project will have a nameplate capacity of 240 MW and is located in Carbon County, Montana, approximately 60 miles south of Billings, Montana. The project consists of 57 Vestas Model V110-2.0 MW safe harbor, 21 Vestas Model V110-2.2 MW safe harbor, four General Electric Model 2.3-116 MW safe harbor, and 32 Vestas model V110-2.2 MW follow-on wind turbine generators ("WTGs").

37. The Pryor Mountain Wind Project is similar to the new wind facilities included in the Energy Vision 2020 Project. The time-sensitive nature of the Pryor Mountain Wind Project is primarily driven by the pending phase-out of the federal Production Tax Credits ("PTCs") for new wind resources. With an in-service date before the end of 2021, the Pryor Mountain Wind Project will be eligible for the full 100 percent PTCs rate. The Company's acquisition and implementation plan for the Pryor Mountain Wind Project is designed to meet the year-end 2020 in-service schedule and provide customers the full economic benefit of the project.

38. Through its wind repowering efforts, PacifiCorp is leveraging past investments in its wind fleet and enhancing the future value of these resources for the benefit of its customers. The Company's repowering efforts now include all of its owned wind resources, including the Foote Creek I facility that was not subject to the Commission's prior order[9] related to repowering. By taking advantage of the unique opportunity to repower this facility, the Company is able to provide efficiency and reliability improvements in wind generation

[9] *In the Matter of the Application of Rocky Mountain Power for Binding Ratemaking Treatment for Wind Repowering*, Case No. PAC-E-17-06, Order No. 33954 (Dec. 28, 2017).

technology to its customers, and return the entirety of its wind fleet to like-new condition, all while enhancing performance, reducing ongoing maintenance expenditures, and reducing customer costs.

39. Foote Creek I, the Company's oldest wind facility, began commercial operation in April 1999. The facility served as a demonstration project to evaluate the feasibility of utility-scale wind energy. The facility was developed in partnership with the Eugene Water & Electric Board ("EWEB") and the Bonneville Power Administration ("BPA"). As developed, Foote Creek I was co-owned by EWEB's 21.21 percent ownership and PacifiCorp's 78.79 percent ownership, with BPA taking 37 percent of the facility's output through a 25-year cost-based Purchase Power Agreement ("PPA"). As the first utility-scale wind energy project in Wyoming, Foote Creek I was sited at one of the most favorable wind sites in the United States and enjoys the highest wind speeds of any of the Company's wind projects. Unlike the remainder of the facilities the Company is repowering, the Foote Creek I project is unique in that it was co-owned and also had a third-party PPA associated with the resource.

40. The Foote Creek I facility currently consists of 68 turbines, each with a 600-kilowatt generating capacity, a rotor diameter of 42 meters, and towers that support a 40 meter hub height. Although employing the latest technology when originally installed, the existing turbines are costly to operate and maintain relative to the Company's more modern turbines that have a much higher nameplate capacity, larger rotor diameters, and taller towers. Since the maintenance requirements for these smaller turbines are similar to those of larger turbines, the operation and maintenance costs of the Foote Creek I facility are the highest of all of the Company-owned wind resources on a per-MW basis.

41. The costs associated with continued operation of the existing turbines at Foote Creek I for both the Company and EWEB would have increased after the expiration of the BPA PPA in April 2024 since 37 percent of these costs would no longer be covered through the cost-based PPA. Similarly, BPA was required to take higher cost energy from the project until the PPA expired. For these reasons, PacifiCorp, EWEB, and BPA were all motivated to explore whether the existing Foote Creek I contract could be unwound in order to achieve an outcome more favorable to customers as compared to continuing to operate the facility through its planned 30-year asset life. Repowering the facility presented the opportunity to realize this outcome for all customers.

42. Repowering Foote Creek I re-qualifies it for PTCs, which are benefits that are passed through to customers. Additionally, repowering increases the amount of zero-fuel-cost energy produced from the repowered facilities given the much larger energy production capability of the new turbines. Further, by replacing older WTG equipment, which is subject to more failure and maintenance issues than newer equipment, repowering will reduce PacifiCorp's ongoing operating costs. Finally, repowering the wind facilities with new WTG equipment will extend the useful lives of the facilities by up to 21 years, creating substantial energy and capacity benefits for customers in the future when this wind facility would otherwise have been retired from service.

43. Repowering Foote Creek I will lower the ongoing capital costs of operating the facility. PacifiCorp's turbine-supply contract for repowering, consistent with wind industry standards for new equipment, includes a two-year warranty on the new equipment. This will reduce capital costs associated with replacing or refurbishing turbine components currently in

service.

44. Repowering will also result in more certainty related to ongoing O&M costs of the facility. PacifiCorp will operate the repowered facility under a full service agreement with the turbine equipment supplier who will be responsible for operating and maintaining the new turbines for a fixed cost while guaranteeing availability of the turbines. Under this agreement, failure to meet the guaranteed availability, if not the result of an excusable event defined in the contract, will result in the payment of liquidated damages to the Company. Customers will benefit by having operation and maintenance costs fixed for the term of the agreement. Thus, there is greater cost certainty related to the run-rate capital expenditures and operation and maintenance costs as compared to continued operation of older turbines that are near the end of their useful life.

45. The Company's wind repowering efforts leverage past investments in PacifiCorp's wind fleet to enhance the future value of these resources for the benefit of its customers. By taking advantage of the unique opportunity to repower this facility, the Company is able to deliver its customers efficiency and reliability improvements in wind generation technology, extend its life by returning the wind fleet to like-new condition, all while enhancing performance, reducing ongoing maintenance expenditures, and re-qualifying the facility for PTCs — all of which reduces customers' rates.

VII. MODIFIED PROCEDURE

46. Rocky Mountain Power believes that a hearing is not necessary to consider the issues presented herein and respectfully requests that this Application be processed under Modified Procedure, i.e., by written submissions rather than by hearing, in accordance with

Idaho Public Utilities Commission Rules of Procedure 201 - 204.

VIII. REQUEST FOR RELIEF

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission issue an order authorizing the Company to: 1) establish a regulatory asset to transfer and recover the decommissioning and closure costs of Cholla Unit 4 when it is retired; 2) approve modifications to Phase II of the Tax Reform Stipulation authorizing the Company to use those funds to buy-down the Cholla net plant balances and offset the 2021 rate increase; and 3) approve RTM ratemaking treatment for Pryor Mountain and Foote Creek I wind resources to match costs with benefits.

DATED: July 2, 2020

Respectfully submitted by,
ROCKY MOUNTAIN POWER

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Mobile No. (385) 227-2476
Email: Emily.wegener@pacificorp.com

Attorney for Rocky Mountain Power

Attachment 1
Rocky Mountain Power - Settlement Terms

Rocky Mountain Power
Case No. PAC-E-20-03 Settlement Terms

May 28, 2020

Settlement Terms in lieu of Idaho General Rate Case

The Company recognizes the impact that the COVID-19 pandemic has on its customers and is ready to face the challenges it presents with its Idaho customers and communities. The Company has suspended residential disconnections for non-payments and is helping accommodate all customers with payment plans. Recognizing any rate increase at this time in particular can be challenging for customers in light of the economic impact of the COVID-19 public health emergency, the Company is proposing two ratemaking measures to delay a general rate increase.

In consideration of COVID-19 and the financial impact to customers the Parties agree to the following approach in lieu of the Company filing a general rate case June 1, 2020:

1. **Case No. PAC-E-18-08 - 2018 Depreciation Study:**
    - The Parties will support adding language in the pending Depreciation stipulation recommending that the Commission authorize the Company to create a regulatory asset to defer the incremental annual depreciation expense of $13,940,303.
    - The deferral would be $1,161,692 per month ($13,940,303 / 12) beginning January 2021 until the incremental depreciation expense is included in base rates.
    - No carrying charge will apply to the regulatory asset until the next general rate case. A carrying charge or rate base treatment and period for amortization of the balance will be determined in the next general rate case and begin at the rate effective date.
    - The depreciation expense tracked in the RTM will be calculated using the depreciation rates approved in Case No. PAC-E-13-02, Order No. 32926, to eliminate any double counting with the $13,940,303.
    - The Company will stop deferring incremental depreciation expense from PAC-E-13-02 currently recovered in the ECAM effective December 31, 2020, because this incremental depreciation expense is included in the $13,940,303 referenced above.
    - Parties agree to support establishment of Phase 2 in Case No. PAC-E-18-08 to evaluate the incremental Decommissioning costs filed with the Commission on January 17, 2020 and March 16, 2020. The Idaho Parties will make all reasonable

efforts to complete Phase 2 in time to allow the Commission to issue a final order before December 31, 2020.

- Ratemaking treatment for the incremental decommissioning costs will be determined in Phase 2, including potentially incorporating any approved incremental expense into depreciation rates and the depreciation deferral for 2021.

2. **Case No PAC-E-20-03 RMP NOI to File a General Rate Case:**

- The Company agrees not to file a general rate case for rates to be effective prior to January 1, 2022.
- The Parties agree that in lieu of a general rate case with rates to be effective January 1, 2021, the Company will file for an accounting order to authorize:
  - A regulatory asset to transfer Cholla Unit 4 net book balance upon closure of the plant in December 2020. The regulatory asset will include other closure-related and decommissioning costs.
  - Modifications to the Phase II Settlement Stipulation in Case No. GNR-U-18-01, on the ratemaking treatment for the 2017 Tax Cut and Jobs Act (TCJA). The Company may propose that the remaining balance from excess deferred income tax savings from the TCJA be retained to buy-down the Cholla Unit 4 and be deferred to offset the January 1, 2022 rate increase.
  - Ratemaking treatment for the Pryor Mountain wind resource and the repowering of Foote Creek I to match costs and benefits with a cost cap amount each year at the benefit level. The Company may propose to include these resources in the RTM/ECAM, consistent with the terms agreed to in Case No. PAC-E-17-07. Prudency will be determined during the next General Rate Case.
- There will be no change to the ECAM baseline NPC of $26.90/MWh (on a sales-basis) established in PAC-E-16-12, until the base is reset in the next general rate case.
- The Company will make its results of operations and cost of service models developed in anticipation of filing a rate case on June 1, 2020, available to parties and the Company will respond to the parties' reasonable data requests regarding the same.

[*Signature page follows*]

Dated: June 3, 2020

Rocky Mountain Power

/s/ Terri Carlock

Staff for the Idaho Public Utilities Commission

Idaho Irrigation Pumper Association, Inc.

Bayer

PacifiCorp Idaho Industrial Customers

/s/ Benjamin J. Otto
Idaho Conservation League

Dated: June 3, 2020

Rocky Mountain Power

/s/ Terri Carlock

Staff for the Idaho Public Utilities Commission

Idaho Irrigation Pumper Association, Inc.

Bayer

PacifiCorp Idaho Industrial Customers

Idaho Conservation League

Dated: June 3, 2020

Rocky Mountain Power

Staff for the Idaho Public Utilities Commission

Idaho Irrigation Pumper Association, Inc.

Bayer

/s/ Ronald L. Williams

PacifiCorp Idaho Industrial Customers

Idaho Conservation League

CSEM WP 195

To What Electricity Price Do Consumers Respond? Residential Demand Elasticity Under Increasing-Block Pricing

Severin Borenstein

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To What Electricity Price Do Consumers Respond? Residential Demand Elasticity Under Increasing-Block Pricing

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Abstract: It is straightforward to evaluate how a perfectly-optimizing, perfectly-informed customer will respond to a non-linear price schedule, but such a customer is rare. In the common case of increasing-block pricing of water and electricity, consumers do not know what marginal price they face during a billing period, because they do not know what demand shocks will occur during the period. If consumers instead set optimal behavioral rules based on the distribution of possible marginal prices they will face (*e.g.,* turn off lights in unused rooms, set the A/C to 74 degrees, replace incandescent lights with CFLs), their consumption will not exhibit discrete responses to the discrete jumps in the price schedule. Using data from a large electricity utility, I show that the empirical distribution of consumption quantities is not consistent with consumers accurately knowing and responding to the marginal price they will face. I then estimate the price elasticity of demand using a panel of household observations at two-year intervals, identifying elasticity from the changes in the increasing-block price schedule. The results suggest that most consumers are probably responding to the *expected* marginal price or even less precise information about what marginal price they will face. The results are difficult to reconcile with the common approach of estimating demand elasticity as a function of the *ex post* marginal price that the consumer faces along an increasing-block price structure.

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I. Introduction

Non-linear price schedules are probably as old as commerce. They can be as simple as an up-front fee before the first transaction and then a constant marginal price per unit bought, or they can be far more complex, with many changes in marginal price as quantity changes. For any schedule, it is generally straightforward to write down how the perfectly-optimizing, perfectly-informed consumer would respond, purchasing at a point at which the consumer's marginal value of the product is equal to (and dropping below) the marginal price she faces.

In reality, consumers make such decisions with limited information, attention and cognitive abilities. In such circumstances, they will engage in behavior that may depart significantly from the perfectly optimizing paradigm. The constrained optimizing behavior in which a consumer does engage may still be a fairly sophisticated response to the limited information environment, or it may be a very simple rule of thumb. Or the consumer's decision may be based on persistent misperceptions that lead to sub-optimal decisions.[2] The degree of attention invested in the decision probably also depends on the magnitude of its impact. Consumers are likely to put more effort into decisions when thousands of dollars of consumer surplus are at stake than when it is just a few dollars.

Since the early twentieth century, utilities have used non-linear prices in selling water, natural gas and electricity. For most of that time, the non-linear schedules have exhibited declining average, and in some cases marginal, price. In the last 30 years, increasing marginal price schedules have become more common in utility sales of water and electricity for residential use. Generally, these are "increasing-block" price schedules, so named because of their staircase nature, with one constant marginal price up to some quantity level and a higher marginal price for consumption above that quantity.[3] In some cases, the schedule has more than one "step" at which the marginal price increases. Figure 1 illustrates the electricity price schedule of Southern California Edison during the spring of

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[2] See, for instance, Stango and Zinman, forthcoming.

[3] Increasing block pricing is not used for commercial or industrial pricing in part, at least, because of the much larger range of electricity consumption among these customers than among residential.

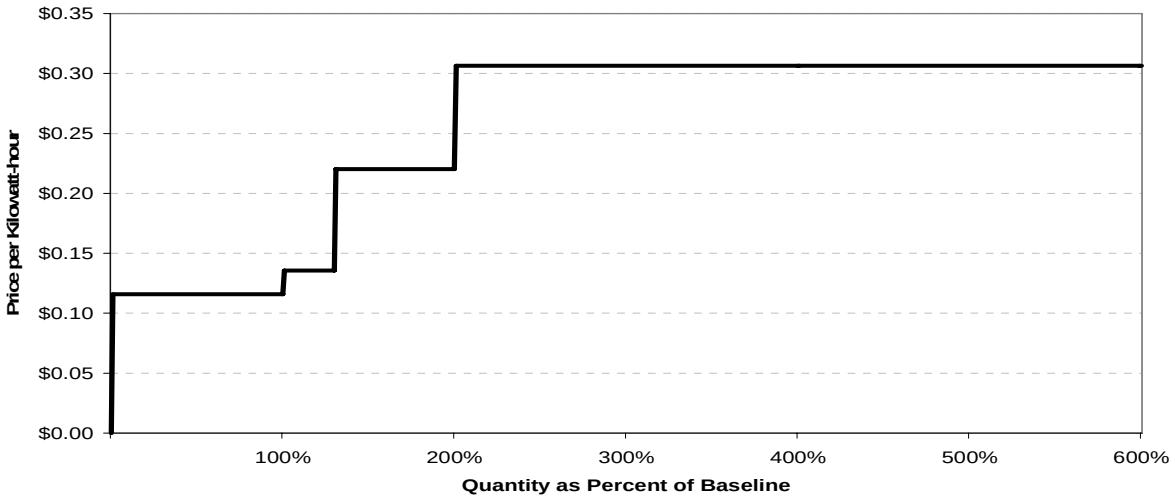

Figure 1: Increasing-Block Residential Electricity Tariff of Southern California Edison, 2006

2006 for sales to a residential customer.[4]

Whenever prices are not constant (and, occasionally, even when they are) economists are tempted to use the data to estimate demand elasticity. Such has been the case with non-linear price schedules for water and electricity, where a substantial literature has developed with the goal of estimating price elasticities from static, but non-linear, price schedules.[5] Most of this literature, however, has been based on the maintained assumption that customers are perfectly informed and perfectly optimizing on the margin at every moment. While internally consistent, such an assumption seems to be at odds with the way nearly everyone actually thinks about their residential water and electricity consumption. It seems safe to say that not only do most consumers not know how much power or water they have used since their current billing period began, most consumers don't know when their current billing period began.

Some of the previous research has recognized that customers may exhibit "optimization

[4] Most residential electricity tariffs also include a daily service charge that is independent of usage, but this generally makes up a very small proportion of the bill.

[5] In electricity, see Taylor (1975), Henson (1984), Shin (1985), Herriges & King (1994), Reiss & White (2005) and Bushnell & Mansur (2005). Of these, Shin and Bushnell & Mansur consider in depth the possibility that customers cannot or do not optimize on the marginal price they face. A similar literature exists in water pricing. See Hewitt & Hanemann (1995) and Olmstead, Hanemann & Stavins (2007). Liebman and Zeckhauser (2004) treat directly the issue of sub-optimizing consumer behavior in the face of complex price schedules.

error," the consumer failing to hit exactly the consumption quantity that she had intended within a billing period. These works take a step towards reality, but sacrifice some degree of internal consistency. They assume that consumers imperfectly hit the optimized consumption for which they have solved, but they assume that consumers themselves do not respond to the fact that they will hit their consumption target with error.

In this paper, I first present a model of consumers engaging in constrained consumption optimization when facing an increasing-block price schedule. The model is intended to better reflect how real-world residential electricity and water consumers are likely to behave. In it, consumers make "behavioral rule" decisions about their consumption patterns before the consumption period begins, then exogenous shocks to quantity demanded occur during the consumption period, but consumers do not change their behavior in response to the fact that the exogenous shocks change the marginal price they face. In setting their behavioral rules prior to the period, however, consumers are aware of the distribution of the potential shocks and optimize over that distribution. The model is an alternative to the perfectly-optimizing model, as well as to a simple rule-of-thumb model in which customers respond only to the average price of power.

In the remainder of the paper, I then explore the empirical relevance of all three models. Using household-level billing data from Southern California Edison, a utility with more than four million residential customers, I first compare some consumption patterns in the data with what one would expect to see under each model. I show that the cross-sectional distribution of quantity demanded in the data is not consistent with a perfect-optimization view of consumer behavior even when optimization error of up to 10% is incorporated. The finding is difficult to square with attempts to estimate the price elasticity of demand that rely heavily on the perfectly-optimizing model and are identified from consumer response to the abrupt changes in marginal price along the increasing-block price schedule.

Because the data include the years 2000 to 2006, I am then able to estimate demand for electricity identified by changes in the residential tariff that occured over time. While a dataset that is a panel of household-level consumption and prices suggests that fixed-household-effect estimation might be revealing, I argue that short-run and long-run mean reversion in household consumption make this approach less robust than one might think. I propose an alternative estimation strategy, based on distributions of consumption in small

geographic areas, that is likely to be more robust.

Attempting to characterize any one of the three customer-behavior models as the single correct model would be obviously misguided. There is certainly a continuum of types of decision-making consumers, from those who pay little attention to their electricity bills and do not even know the pricing structure, to those who scrutinize their bills in detail and closely monitor their consumption in order to respond optimally to changes in marginal price. It is valuable, however, to develop an understanding of the distribution of the population across these types. Such information, for instance, would be quite helpful in forecasting the impact of a shift from a flatter price structure to a steeper increasing-block structure. The results of the demand estimation suggest that of the three customer-behavior models, both the average-price-response model and the constrained-optimization model have significant explanatory power, but the perfect-optimization model has comparatively little.

II. Models of Customer Response to Increasing-Block Pricing

In the standard model of customer response to increasing-block pricing, the buyer has an inverse demand function that represents her marginal value of consumption during a billing period as a function of quantity, q, and other demand shifters, $\mathbf{X}$: $P = P(q, \mathbf{X})$, where demand is downward sloping, $P_1 < 0$.[6] The buyer faces a discontinuous marginal price schedule such as shown in figure 1. The buyer then optimizes through a series of inequality constraints. If the price schedule were a simple two-block structure – p_1 for $0 < q < \hat{q}$ and p_2 for $q > \hat{q}$ – then the optimal consumption would be

$$
\begin{aligned}
q &= P^{-1}(p_1, \mathbf{X}) && \text{if } P(\hat{q}, \mathbf{X}) \leq p_1 \\
q &= P^{-1}(p_2, \mathbf{X}) && \text{if } P(\hat{q}, \mathbf{X}) \geq p_2 \\
q &= \hat{q} && \text{if } p_2 > P(\hat{q}, \mathbf{X}) > p_1.
\end{aligned}
$$

From the fact that the customer faces a discrete marginal price shift at $\hat{q}$ has emerged

[6] A bit of attention to income effects is needed at this point, because a non-linear price schedule means that the usual relationship between substitution and income effects may not hold, depending on how the infra-marginal price changes relative to the marginal price a customer faces. In the case of electricity, however, income effects are likely to be extremely small. For a median customer in these data, with a \$50/month electricity bill, even a 50% change in *average* price would mean an income change of \$25/month, about 0.6% of monthly median household income. Typical estimates of the income elasticity of electricity demand is between 0.5 and 1.0. So, the income effect of this large price change would be a quantity change of less than 0.6%. The empirical work suggests that even with very price-inelastic demand, this is a small component of the effect.

the argument that price elasticity of demand may be estimated from a single static price schedule. Reiss & White (2005) explain the approach:

> Intuitively, one can use the variation in consumption among all households on the same tariff segment to identify the non-price components of demand. Given that, the effect of price can be determined from the remaining difference in average consumption between households on different tariff segments, less the average difference in their unobserved characteristics. The latter is computable from the marginal distribution of ϵ *(unobserved consumer characteristics)* and the price schedule. Researchers can therefore estimate demand without price schedule variation, provided one is willing to place some distributional restrictions on ϵ.

Econometrically, estimation of this model has been done in a linear regression by instrumental variables[7] or with a mixed discrete/continuous choice (DCC) model estimated by maximum likelihood or with a method of moments estimator.[8] In the DCC models, consumers are assumed to calculate their preferred consumption if they were to face each of the possible marginal prices on the different steps and then choose on which of the steps to consume. These approaches, however, rely on discrete price changes at identifiable points and on the assumption that consumers respond to those abrupt price changes. That is, these papers assume that consumers chose their consumption quantity based on the marginal price that they are observed to have faced. Some research recognizes that consumers do not exactly hit their consumption target in every billing period due to variations in daily activities, weather, and other factors. This optimization error is argued to be part of the error term.

In practice, this view of consumer behavior is quite demanding. First, it has the obvious information requirements that the customer knows the date his current billing period began and will end, and the prices and quantity break points in the increasing-block schedule. More importantly, if there are any exogenous shocks to his demand, this approach requires that the consumer knows (or, at least thinks he knows) those shocks with certainty for the entire billing period at the time the period begins. Otherwise, when the consumer is choosing consumption on day 1 of the billing period he will not know the marginal price on which he should base his decision.

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[7] See Henson (1984), Shin (1985), Herriges & King (1994) and many of the papers reviewed in Taylor (1975).

[8] See Hewitt & Hanemann (1995), Reiss & White (2005), Olmstead et al (2007), and Olmstead (2008).

Consumers, of course, don't know exactly how their lives and electricity demand will evolve over the next month, so even if they were as compulsive as the model suggests, they would still have to make guesses throughout the period about the marginal price they will face for consumption.[9] Furthermore, it seems realistic to say that consumers know that they don't know the future and, as a result, rather than responding to the actual marginal price that results at the end of the period, they would be optimizing based on an expected marginal price. If there is much uncertainty about consumption over the entire billing period, this means that much of the consumption will be based on a guess of the ultimate marginal price that is a probability-weighted average of prices on the different steps. Those probabilities, and the expected marginal price, change smoothly with the expected consumption level. Thus, a customer whose final consumption ends up being five percent less than $\hat{q}$ may have made most of his consumption decisions based on an expected price that differs only slightly from the expected price of a consumer whose final consumption ends up being five percent more than $\hat{q}$.

More realistically still, it seems likely that the vast majority of customers do not monitor their consumption relative to the price schedule during a billing period. Even that level of monitoring would require knowledge of the beginning and end dates of the billing period and frequent visits to the meter (as well as knowledge of how to read the meter) and record-keeping during the billing period. Such behavior is, to say the least, rare.

I propose an alternative model in which the consumer sets behavioral consumption rules – *e.g.,* turn off the computer at night, buy a more energy efficient refrigerator, replace some incandescent bulbs with compact fluorescents, set the A/C at 76 degrees – prior to the period based on an expectation of marginal price and does not update the rules until he receives feedback in the form of an electricity bill for the period. To be concrete, assume that the consumer has quasi-linear utility

$$U = V(q(r, X), X) + (I \quad B(q(r, X))) \qquad [1]$$

where $V(\cdot)$ is the utility derived from electricity consumption, which is a direct function of the quantity consumed and demand shocks, and the quantity consumed is a function of the consumption rules, r, adopted and demand shocks. The consumer controls q only

[9] Albeit, these would be increasingly well-informed guesses as the end of the period approaches.

through adjustments to r, which must be set before knowing X. The second term is the residual income, total income minus the electricity bill, which is a non-linear function of electricity consumption.[10]

The consumer chooses r to maximize expected utility over the distribution of possible X values. Expected utility is

$$E[U] = \int [V(q(r,X),X) + (I \quad B(q(r,X)))] \; f(X) \; dX \qquad [2]$$

Setting the derivative of $E[U]$ with respect to r equal to zero gives

$$\int \frac{dV(q(r,X),X)}{dq(r,X)} \; \frac{dq(r,X)}{dr} \; f(X) \; dX = \int \frac{dB(q(r,X))}{dq(r,X)} \; \frac{dq(r,X)}{dr} \; f(X) \; dX \qquad [3]$$

Equation [3] shows that the consumer will set r so that the expected marginal value from changing r slightly, taken over the distribution of X, is equal to the expected marginal change in his electricity bill from that change in r, taken over the same distribution.

A similar issue of constrained optimization has arisen in the study of labor supply response to increasing marginal tax rates.[11] Saez (2002) proposes a similar model in which the worker must choose effort before knowing an exogenous shock to his income. The variation here is that both the benefit and cost of the activity are potentially affected by the shock. That is, the marginal value of electricity is also dependent on the exogenous shock, not just the marginal cost of electricity, and the choice variable is therefore a consumption rule, rather than the target consumption quantity itself, that must be set before knowing the shock. For example, the typical consumer's marginal value of electricity is dependent in part on the weather, so even with price certainty it is more likely that she would decide *ex ante* on a given thermostat setting (a behavioral rule) rather than a target consumption level.

If the distribution of X is massed as a point, then r is just the deterministic optimal response to that X and the $B(\cdot)$ function, and [3] simplifies to the standard marginal price optimization that many earlier papers have assumed. Some papers have recognized that

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[10] This quasi-linear utility function eliminates income effects, which I argued in footnote 6 is a reasonable approximation over the relevant price schedules.

[11] See Hausman (1981), Hausman (1983), Heckman (1983) and Saez (2002).

X has a non-degenerate distribution, but within this formulation, they have assumed that customers ignore uncertainty in X when choosing r. Instead, consumers are assumed to base their decision on expected X, and are then consistently surprised that their quantity consumed is not what they had planned, resulting in the previously-mentioned optimization error:[12]

$$\frac{dV(q(r,\bar{X}),\bar{X})}{dq(r,\bar{X})}\ \frac{dq(r,\bar{X})}{dr} = \frac{dB(q(r,\bar{X}))}{dq(r,\bar{X})}\ \frac{dq(r,\bar{X})}{dr}. \qquad [4]$$

Even the constrained optimization model I propose assumes what may seem to most people an unusual degree of involvement with one's electricity consumption. Many people are unaware of the existence of an increasing-block price schedule or where the jump points are in the schedule relative to their consumption.[13] Many people also are unaware of the amount of electricity they consume (or even the units in which it is measured). These people might still respond to changes in their bills, but they might, for instance, not distinguish between a change in the marginal price they face on a given schedule and an overall change in the price schedule. For such people, the constrained optimization model might far exceed their sophistication of decision making. Therefore, a third model that I consider is that consumers respond to the average price of electricity they are charged. These consumers are assumed to have a rough idea of their consumption and to be able to infer roughly their average price, but they cannot or do not infer their expected marginal price of consumption.[14]

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[12] A model of "perfect optimization under uncertainty" is also possible in which the customer starts the billing period with a believed distribution of the marginal price he will face and constantly updates (and narrows) that distribution, and changes r in response, as X is revealed over the billing period. While this is technically plausible, it still requires much more attention to optimization in electricity consumption than one generally observes. This behavior would manifest, for instance, as the customer setting his air conditioning to a higher temperature near the end of the billing period – controlling for current weather conditions – if previous days had been unusually hot because he is more likely to face a higher marginal price in that billing period. I do not model this behavior explicitly, but it is clear that the implications would lie "between" the perfect optimization model and the constrained optimization model.

[13] Until a redesign of utility bills in 2008, SCE residential bills did not give a customer information about the marginal price of consumption above the tiers on which he is consuming. Even calculating it from their website required merging of data from different web pages.

[14] Evidence in support of this model comes from at least two common practices. First, energy efficiency tags on refrigerators and other appliances give a range of price impact comparisons based on the average

Intuitively, it is clear that both the constrained optimization model and the average-price optimization model will not yield the sort of customer behavior that is assumed for the marginal-price optimization approaches to elasticity estimation from increasing-block pricing. The price schedules that consumers optimize against will not exhibit discrete jumps. I examine these implications empirically in section IV after introducing the data in the next section.

III. Data and Sources

The primary data for this analysis come from residential billing records of Southern California Edison, which were made available to the U.C. Energy Institute under a confidentiality agreement. The dataset used in this analysis includes virtually all residential bills for 1999-2006. Customers who were not individually metered, but instead are part of a "master-metered" building or other location, were not included in the data. In aggregate, such accounts constitute less than 3% of residential consumption at SCE.

The increasing-block tariff structure implies an increasing *marginal* price for electricity. A SCE customer whose consumption level puts him or her on the highest tier, for instance, still pays the lower-tier rates for consumption up to the highest tier.

The marginal rate that a residential customer pays increases as consumption increases relative to a "baseline" consumption level. A household's baseline allocation is supposed to correspond to a minimal basic electricity usage. The baseline, however, is the same for all residential customers in a region regardless of the size of the residence or the number of people who live there. Within the region, a studio apartment receives the same baseline allocation as a four-bedroom house.[15] Baseline allocations do differ by geographic regions within the utility area: SCE's service territory is divided into 6 different baseline regions. This is argued to reflect variation in basic electricity need due to climate differences, but in practice baselines are set based on different average usage across regions. As a

price of electricity in different areas of the country, and the range does not include the prices on the upper tiers of California rates. More surprisingly, many vendors of residential solar photovoltaic systems in California advertise bill savings from such systems that are calculated based on the average price of electricity rather than the marginal price of replaced kilowatt-hours. The latter is likely to be much higher for customers that the solar PV vendors are targeting in California.

[15] The baseline allocation is higher for customers who have electric heating systems and some other electrical appliances.

result, variation is driven not only by climate differences, but also by wealth levels, average residence size, and choices to install air-conditioning.[16]

Prior to the California electricity crisis in 2000-01, SCE had a two-tier rate structure with an 18% price difference between the steps. All consumption above the baseline level was charged at the second-tier rate. After the electricity crisis, a 5-tier tariff was implemented with marginal price changing at 100%, 130%, 200% and 300% of baseline. Prices were virtually frozen for consumption up to 130% of baseline, the bottom two tiers, but were increased substantially for higher tiers. In later periods, the fourth and fifth tiers have sometimes been assigned the same marginal rate.[17]

Not all of SCE's residential customers are on the standard tariff. The largest exception from the standard tariff is customers who are on the CARE (California Alternate Rates for Energy) program, which is an income-based program that offers lower rates to low-income customers.[18] About 27% of SCE's customers were on CARE in 2006, up from 11% in 2000. The CARE program is advertised as offering "a 20% discount" off the standard residential rates, but not all components of the bill are included in the discount and some fees are excluded entirely for CARE customers. In practice, the discount is 20%-30% on the lowest two tiers of consumption and greater than that for higher tiers. I exclude CARE customers from the price elasticity analysis, as explained in more detail below.

A small number of customers are on special tariffs that incorporate time-of-use electric-

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[16] I drop bills with outlier quantities, which were defined as less than 2 kWh/day or more than 8 times baseline consumption. A refrigerator typically uses at least 1-2 kWh/day, so it is implausible that an occupied primary residence would fall below 2 kWh/day. The 8 times baseline upper bound is over 120 kWh/day per day for a typical house in the summer. This translates to a constant consumption of 5 kW at all time which would require a large central air conditioning unit to be running (not just turned on, but never cycling off) practically continuously. A small share of bills are based on estimated usage because meter readers are unable to access the meters. SCE reported during the sample period that about 0.4% of residential bills were based on estimated usage. These are not identifiable in the dataset, so no attempt to adjust for estimation is made.

[17] Under SCE's standard residential rate during March-May 2006, a customer with a baseline consumption allocation of 300 kWh during a given billing period who actually consumes 1100 kWh would pay 11.58¢ for each of the first 300 kWh, 13.55¢ for each of the next 90 kWh, 22.03¢ for each of the next 210 kWh, 30.65¢ for each of the next 300 kWh, and 30.65¢ for each of the last 200 kWh (tiers 4 and 5 had the same marginal rate in 2006).

[18] For June 2008 through May 2009, a residence with one or two occupants must have a household income no higher than $30,500 in order to qualify for CARE, with the threshold increasing by $5,300 for a third occupant, and by $7,400 for each additional occupant.

	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
Range of Tier (as a percentage of baseline)					
	0% -100%	**100%-130%**	**130%-200%**	**200%-300%**	**300% and up**
Percentage of Total Residential Usage					
	55.2%	11.1%	16.9%	10.8%	6.0%
Percentage of Customers on Tier for Marginal Consumption					
	32.0%	14.5%	25.5%	17.5%	10.4%
Marginal Electricity Price ($/kWh)					
	0.1158	0.1355	0.2203	0.3065	0.3065

Table 1: Percentage of kWh sold and Percentage with Marginal kWh on Each Tier in 2006 (non-CARE customers only)

ity pricing, special rates for SCE employees, for people with electric vehicles, and other idiosyncratic rate structures. In aggregate, these nonstandard tariffs cover less than 1% of residential customers and residential consumption.[19] Most of these customers still face a five-tier tariff with the same baseline allocation and breakpoints between the tiers as if they were on the standard residential tariff, but with somewhat different rates. I exclude these customers as well from elasticity analysis.

Regardless of the tariff that a customer is on, the customer has an assigned baseline consumption and his or her monthly consumption can be allocated across the tiers shown in table 1. For customers not on the CARE program, the top row of table 1 shows the total quantity of residential consumption that was billed on each of the tiers during 2006, the last year included in this analysis. The second row of table 1 shows the proportion of households whose average daily consumption puts them on each of the five tiers for their marginal consumption. Among SCE's non-CARE customers, 32% consume less than the baseline and therefore face the tier 1 price for their marginal consumption, while 10.4% consume more than 300% of baseline so face the tier 5 price for their marginal consumption.

Typically, a residence receives a bill about every 30-33 days, but the number of days

[19] One larger program is the "automated power shift" (APS) program that allows SCE to cycle off residential air-conditioning units for short periods of time. This program, however, operates only during the summer and impacts only summer rates.

varies over time even for a given premises. The customer's baseline consumption for the billing period is his *daily* assigned baseline multiplied by the number of days in the billing period. With that baseline consumption figure for the period, total consumption can be allocated across the tiers. Combining these data with historical residential tariff information and matching the consumption across tiers to the contemporaneous residential tariff then yields the customer's total bill for electricity (before any daily connection charge, bill adjustments, or other fees that are independent of the level of consumption), as well as the marginal price that the customer faced.

The data do not include the address or the name of the customer. They do, however, include the nine-digit ZIP code, which allows a fairly precise neighborhood matching with census data. Summary household demographic data are available from the U.S. Census at the level of census block group (CBG), a geographic designation that on average includes about 600 households in SCE territory. Census block groups are considerably larger than the areas associated with nine-digit ZIP codes. Each nine-digit ZIP code is assigned to the CBG in which it was located.[20]

IV. Evidence About Customer Optimization

As described earlier, nearly all of the literature that has estimated customer price elasticity in response to increasing block pricing has assumed that customers optimize on the *ex post* observed marginal price that they face.[21] Some have assumed that customers implement this strategy with some error. If this were the case, one would expect to see customers "bunched" around the points where the marginal price increases. This is the standard result of a kinked budget constraint. Saez (2002) examines a similar phenomenon regarding labor supply decisions around income levels at which marginal income tax rates change, an issue that was discussed two decades earlier by Heckman (1983) and Hausman

[20] A small number of customer records did not include a nine-digit ZIP code, or did not match to a nine-digit ZIP code in the census data. In the case of nine-digit ZIP codes that did not match to the census data, I used the numerically closest nine-digit ZIP code. In the case of having only a five-digit ZIP code, those customers were allocated probabilistically among all of the nine-digit ZIP codes within the five-digit ZIP code based on the share of households that were in each of the nine-digit ZIP codes.

[21] Assuming that customers optimize on the *ex post* marginal price is not equivalent to ignoring endogeneity, nor is the problem alleviated by correcting for the endogeneity of price.

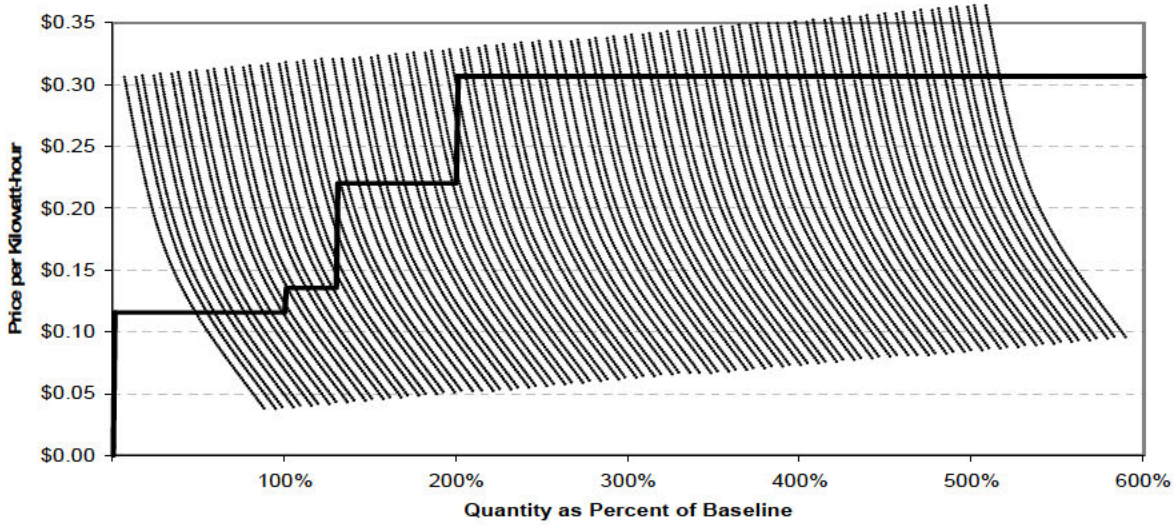

Figure 2: Uniform Distribution of Demand Functions and Bunched Quantities Demanded

(1981, 1983). Saez finds evidence of much less bunching than optimizing behavior would suggest. I find a similar result for changes in marginal electricity rates.

Figure 2 illustrates why one would expect to find bunching at the quantities where marginal electricity price increases. If the distribution of customer demand functions is smooth around these marginal price changes, then a disproportionate share of customers should be observed choosing consumption that is exactly at the point of price increase.[22] While in practice customers are not likely to target their consumption down to the last kilowatt-hour, one would expect to see a tendency to be much more careful about further consumption increases at the points where the marginal price increases, and that would result in bunching. If customers try to optimize, but have very large optimization error, then there would be little or no bunching, but there would also be less hope of identifying demand elasticity based on responses to the jumps in the *ex post* observed marginal price.

The potential magnitude of the bunching effect is illustrated in figures 3 and 4. Figure 3 shows a fairly typical distribution of customer demand quantities under a flat-rate tariff.[23]

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[22] In the absence of uncertainty, the conditions for finding this bunching for optimizing consumers are quite weak. It requires only that demand has elasticity less than zero and the distribution of demand functions does not happen to have large troughs right around the quantities where the steps in the tariff occur. The normal unobserved (to the econometrician) customer heterogeneity that justifies the usual regression error would not reduce the level of bunching one should observe in the data. Optimization error does reduce bunching, as discussed below.

[23] This is actually taken from the distribution of SCE customer quantities demanded in 1999 when there

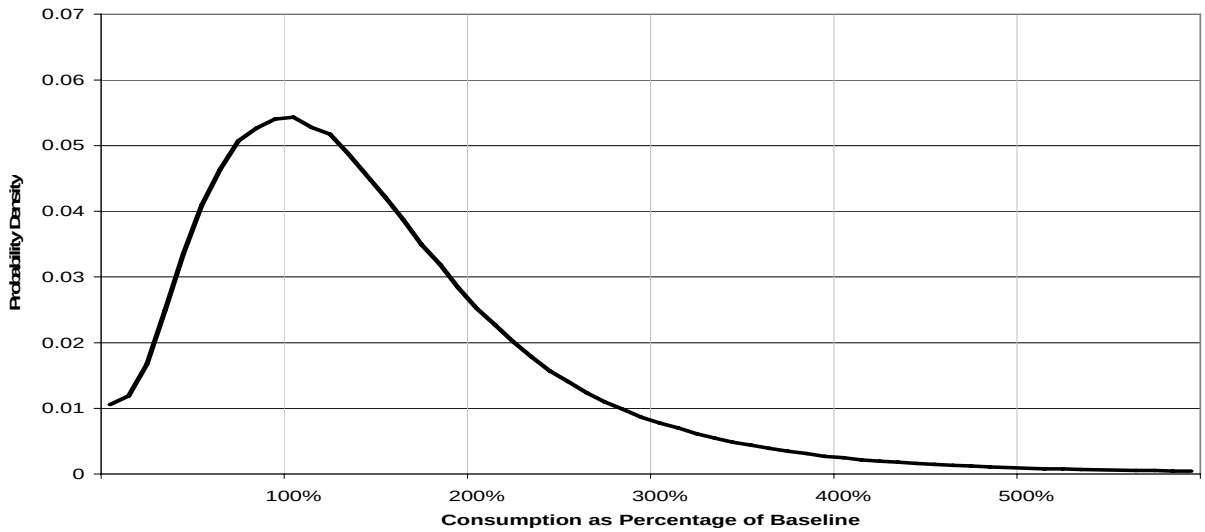

Figure 3: Distribution of Quantity Without Retail Bill Tiering

If this distribution were the result of a population of customers each with a demand function $q_i = a_i p^\epsilon$, then one can determine the distribution of the a_i, $h(a_i)$, for any p, ϵ, and population of q_i. With that empirical distribution of a_i, it is straightforward to calculate the share of customers that should be observed consuming in any quantity interval. Figure 4 illustrates this exercise using the distribution from figure 3, assuming a demand elasticity of -0.1 and SCE's standard residential 4-tier price schedule that was presented in figure 1. The figure is constructed using quantity intervals of 10% of the baseline consumption quantity for the frequency calculations. Customers who would, theoretically, consume exactly at the quantity at which a price change occurs are allocated equally to the two adjoining intervals. This allows for optimization error – the failure of a household to hit exactly the consumption level that it targets – uniformaly distributed across plus or minus 10% of baseline quantity or about 7% of the average household's consumption.

The calculation suggests that for the largest step in SCE's tariff, which occurs at 130% of baseline, there should be bunching in the adjoining 10 percentage point intervals that creates about a 35% bump in the population of those intervals compared to linear interpolation between adjoining intervals. For the second largest step in SCE's tariff, at 200% of baseline, the bump should be about 30%. If one assumes instead that optimization error spreads actual consumption uniformly around the desired quantity by 20% of baseline,

were only two-steps to the tariff with a 18% price increase.

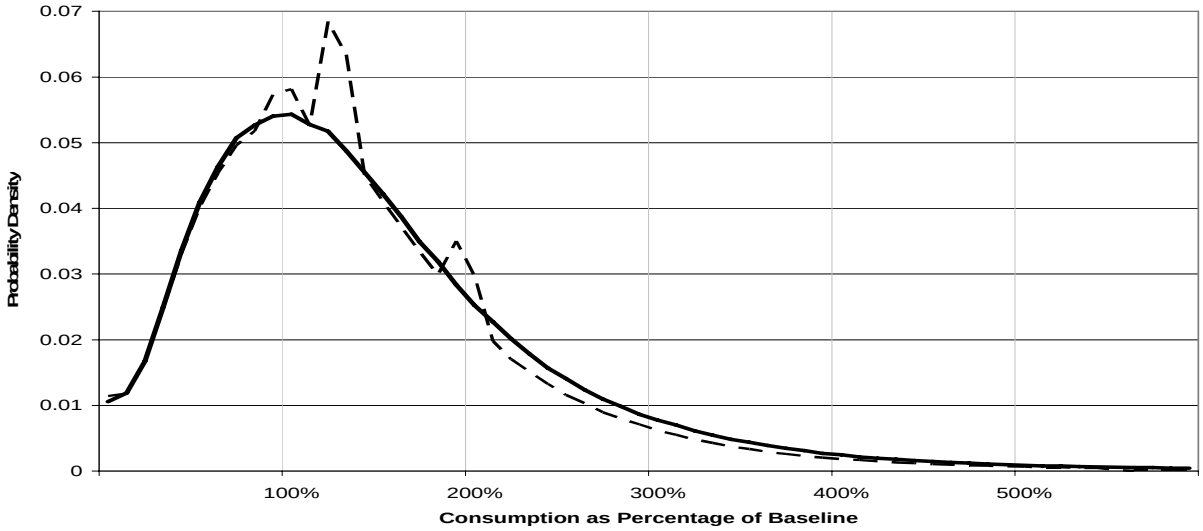

Figure 4: Simulated Distribution of Quantity Demanded Under SCE's 2006 Four-Tier Tariff

instead of 10% of baseline, that cuts the size of these peaks in the distribution by half, but still leaves them quite large. On the other hand, if one assumes a long-run demand elasticity of -0.2 or larger that makes the peaks more pronounced.[24]

Figure 5 presents the actual observed effect of the increasing marginal prices for SCE customers for all bills in March, April and May 2006 or, more accurately, the absence of such an effect. Similar non-effects are evident for other years.[25] The hypothesis that the actual distributions could be a random outcome of draws from the theoretical distribution that would result from marginal price optimization with optimization error up to plus or minus 10% of baseline is clearly rejected.[26] This seems to be inconsistent with estimates of demand elasticity based on optimized customer response to changes in marginal prices along the schedule, though a sufficiently large optimization error would, of course, eliminate the bunching, which I discuss further below.

This is not to say that consumers never respond to marginal prices for electricity, nor

[24] Reiss & White (2005) report an elasticity of -0.39. Theirs is a medium-run estimate of sorts because it is based on cross-sectional consumption variation, but holds constant appliance ownership. Their estimate would imply very significant bunching.

[25] Likewise, 2006 data for the other two investor-owned utilities in California – Pacific Gas & Electric and San Diego Gas & Electric – also show no bunching.

[26] Figure 5 is based on about 12 million billing observations over more than four million households.

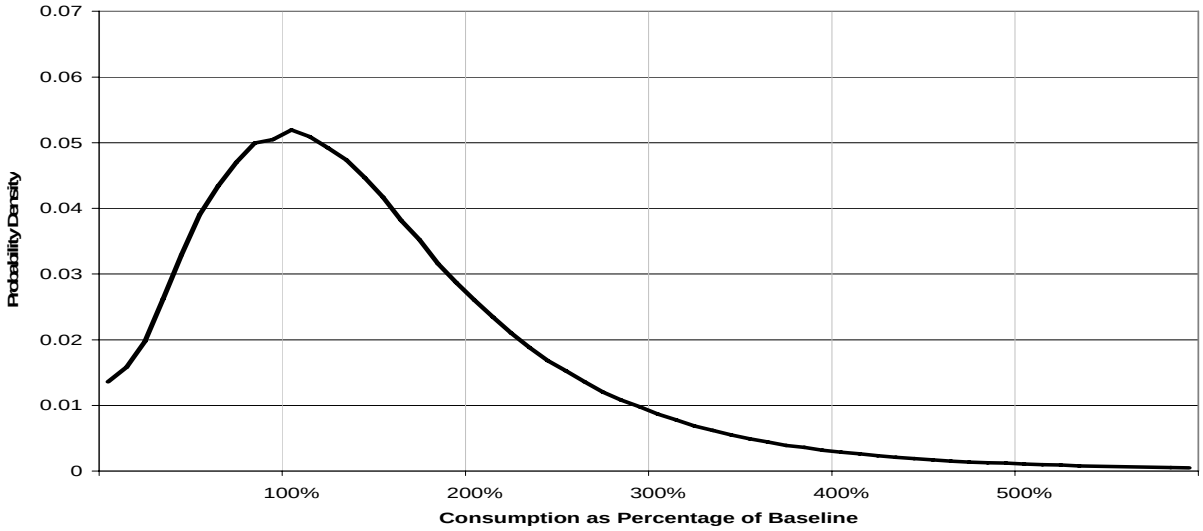

Figure 5: Actual Distribution of Quantity Demanded Under SCE's 2006 Four-Tier Tariff

that they would fail to show additional response if they were given more information in a sufficiently clear format. In the case of SCE, however, the evidence is quite strong that consumers are not responding to marginal prices in the way that the simplest consumer theory would predict. This leaves the questions of what, if any, notion of price customers do respond to, and how sensitive this is to the amount and type of information the utility gives the customer. The data available for this study do not allow analysis of the second question, but time series of data from SCE do allow a broader analysis of customer price response.

How Predictable is Customer Usage and Marginal Price?

As illustrated in section II, the degree to which the standard estimation of residential electricity demand – based on marginal-price response to increasing-block pricing – captures consumer behavior depends in part on the consumer's predictability of his own demand and the amount of "optimization error." Such uncertainty also affects how a constrained-optimizing consumer will respond to an increasing-block schedule. Studying time series data on customer usage gives an idea of the size of the uncertainty.

To explore this issue, I selected from the SCE dataset a random sample of 10,000 customers with at least 60 bills, or about 5 years, in the dataset. For each customer separately,

the following regression was estimated:

$$ln(Daily_Use)_t = \sum_{j=1}^{12} \alpha_j \cdot Month_j + \beta \cdot ln(Daily_Use)_{t-1} + \gamma_1 \cdot t + \gamma_2 \cdot t^2 + \gamma_3 \cdot t^3 + \epsilon, \quad [5]$$

where $Month_j$ are twelve month-of-year dummy variables. The standard error of this regression, the root mean squared error corrected for degrees of freedom (RMSE), is an indication of how well consumers are likely to be able to predict their consumption in a period. This RMSE could be an upward biased estimate of consumer uncertainty if consumers have better information about this month's consumption than is revealed by their typical seasonal pattern, last month's consumption, and a cubic function in time. It could be biased down both because some consumers pay far less attention to consumption than this regression suggests and because most customers have lived in their current location less than 8 years – 8 years is the median length of time that the customers in this subsample were at their location during the sample period – and are working with much less data than is in these regression.[27]

The results from the sample of 10,000 customers indicates an average RMSE of 0.186 and a median of 0.159, suggesting that with this information the average consumer will be able to predict his consumption with a standard error of about 20% (median 17%), or a 95% confidence interval of plus or minus 40% (median 34%).[28] That degree of noise in consumption choice seems likely to make it quite difficult to infer price responsiveness of demand from changes around discontinuities in the marginal price even if customers did not account for the marginal price uncertainty when choosing their behavioral rules.

The implications of that noise are still greater in the context of the constrained-optimization model of consumer behavior. That is, if consumers actually optimize against the fact that there will be very considerable unpredictable variation in their consumption after they set their behavioral rules – and therefore very considerable unpredictable variation in the marginal price they face – then behavior is less likely to exhibit much response to the discontinuities in the price schedule.

[27] I also omit prices from this regression, though given the inelasticity of demand that is a very small effect relative to the RMSE found. I also don't explicitly control for the California electricity crisis in 2000-01 and the public appeals for conservation that accompanied it.

[28] The number is higher in the summer months due to air conditioning, but even in the March-May period on which I focus it is only 1-3 percentage points lower than the overall mean and median.

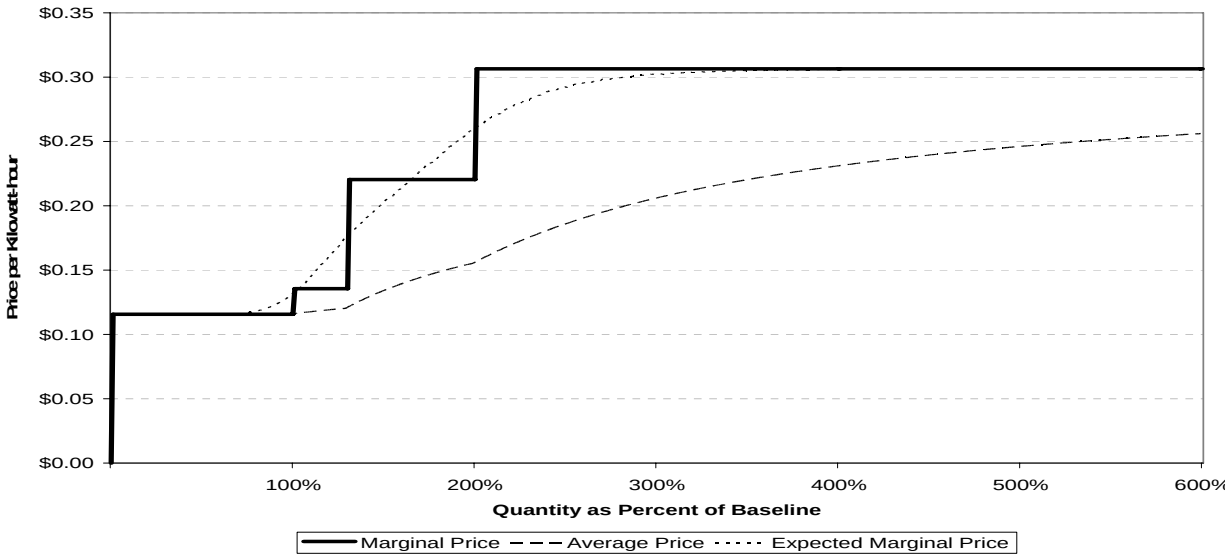

Figure 6: Marginal, Expected Marginal and Average Price Under SCE's 2006 Four-Tier Tariff

A straightforward application of this empirical finding illustrates its implications. In order to focus on the effect of uncertainty over marginal price, assume that the behavioral rules adopted are such that the derivative of utility with respect to the choice of r will be invariant to the demand shock X. This would be the case, for instance, if the rule is "always have W watts of lighting on when I am at home in the evening," and the variation is due to the unpredictability of how often I am at home in the evening.[29] The impact of the demand shock is then only on the marginal price of consumption, the right-hand side of the equation [3]. That is, the consumer will set the behavioral rule in order to equalize the (deterministic) marginal value of changing r with the expected marginal cost of changing r.

Figure 6 shows the SCE price schedule from figure 1 along with the expected marginal price a consumer would face for each possible expected level of consumption, assuming that his actual level of consumption is the expected plus a normally distributed random variable with mean zero and standard error equal to 20% of the expected consumption. As one would expect, the expected marginal price is quite a bit smoother than the underlying

[29] More precisely, the shocks that determine how much time I spend at home in the evening do not affect the marginal value I get from additional lighting when I am at home, so the shocks will not change the optimal r for a given marginal price. This isn't as likely to hold precisely in terms of heating and cooling. The value of lowering the thermostat to 74 degrees from 78 degrees may be different when the outdoor temperature is 80 degrees than when it is 95 degrees.

price schedule. Figure 6 also shows the average price of consumption, which could be relevant for the reasons discussed earlier.[30]

But the impact on the *ex post* observed quantity is even more substantial, because it is equal to the constrained-optimized target quantity plus optimization error caused by a random draw on X. Assuming an error with a standard deviation equal to 20% of the target quantity, Figure 7 presents the *ex post* distribution of quantity that one would expect to observe when the underlying distribution of expected demand is as shown in figure 3 and the elasticity of demand is -0.1. Besides the underlying quantity distribution (under a flat tariff), figure 7 presents the simulated resulting quantity distribution under marginal price optimization with optimization error and expected marginal price optimization with optimization error. Either one is clearly much more consistent with the observed demand quantity presented in figure 5 than is the simulated distribution of quantity demanded under (nearly) perfect optimization in figure 4. The optimization error alone is so large that it would wipe out any noticeable bunching in the data even if consumers were myopically optimizing on marginal price. The same is not true if one assumes 10% standard deviation optimization error or if the long-run demand elasticity were -0.3; in either of those case, simulated marginal price optimization with optimization error still produces noticeable bunching that is not present in the actual data, while expected marginal price optimization with optimization error produces a smooth distribution of quantity demanded.

Thus, if consumers attempt to respond strictly to marginal price, but have large demand shocks that they ignore in their economic decision making, then their resulting distribution of consumption could possibly be consistent with marginal price optimization. This explanation only fits the data if consumers have quite inelastic demand. The behavior still would be internally somewhat inconsistent, a combination of careful marginal optimization on a target marginal price while ignoring the probability distribution of marginal price. A consumer who accounts for the exogenous demand shock in planning consumption – a constained-optimizing view – would face a much smoother expected marginal price function. The resulting patterns of quantity demanded would be very similar if optimization error is sufficiently large and demand is sufficiently inelastic, but myopic behavior would

[30] Average price excludes the 17¢/day connection charge that is independent of consumption.

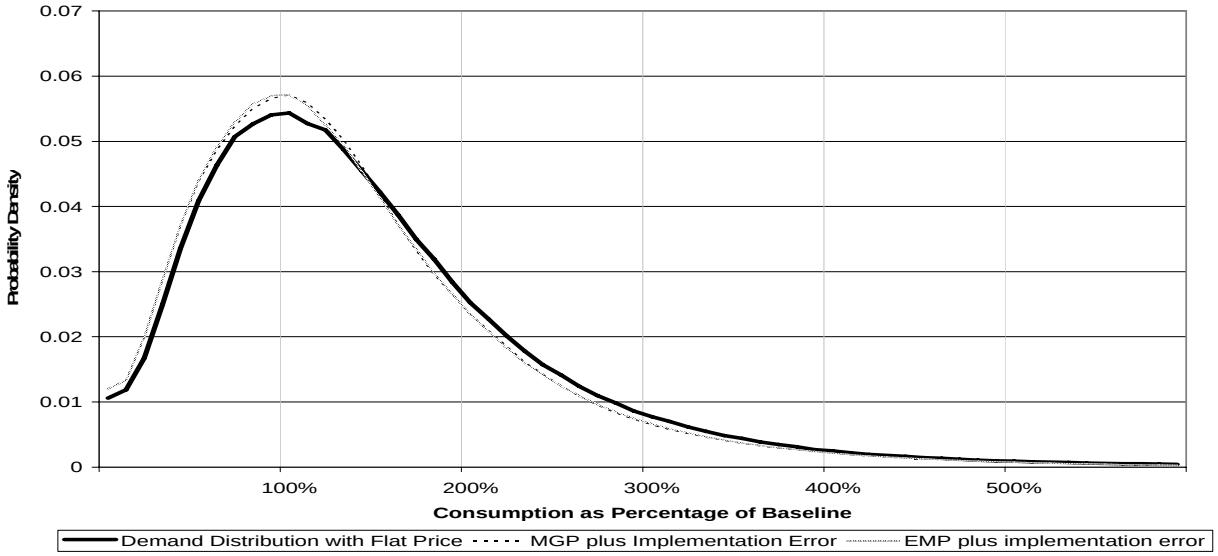

Figure 7: Simulated Demand Distributions with optimization Error

result in more bunching than constrained optimization if optimization error is sufficiently small or demand is more elastic.

Still, as figure 6 suggests, the price against which consumers would respond differs substantially between the theories. Thus, examining the consumption response to changes in price might allow one to distinguish between the theories.

Evidence of Customer Response to Increasing-Block Pricing

While it is clear that consumer response to increasing-block pricing does not reflect precise optimization on marginal price, constrained optimizing behavior would still result in different consumption changes for consumers at different points along the price schedule as the steepness of the price schedule changes. If the price schedule became steeper, one would still expect to see the consumption of heavier users decline relative to the consumption of lighter users.

The data that SCE made available to UCEI go back to 1999, before the California electricity crisis and before the implementation of the five-tier rate structure. In 1999, SCE had a simple two-tier structure with a price of $0.1081 up to baseline consumption and $0.1274 on all consumption above baseline. By late 2001, a five tier structure had been implemented with a top price of $0.2262. Unfortunately for this analysis, many other events

had occurred that could confound the time-series comparison. California's electricity crisis from June 2000 to May 2001 brought public conservation campaigns, threats of blackouts, and explicit conservation rebates during the ensuing summers for households that reduced consumption by at least 20% compared to summer 2000. The rebates were distributed through a lump sum bill credit at the end of the summer, further muddying the analysis.

For these reasons, I focus on a relatively clean comparison of the March through May periods at two-year intervals: customer billing periods that ended in March, April and May of 2000, 2002, 2004 and 2006. Figure 8 shows the retail rates that were in effect during each of these periods. These are the rates for each tier averaged over each 3-month period, but there was very minor variation across months within each 3-month interval. There was also very little tariff variation for the prior two months (with the exception of 2006, when a significant rate increase occurred in January) so customers had already received at least one bill at these rates prior to March. Besides the rate stability and absence of distorting events during these periods, these months also have the advantage of falling entirely within the winter baseline period, so there is no confusion within the data – and, one hopes, relatively little confusion on the part of consumers – that would result from changes in customer baseline quantities during the month. Figure 8 shows that rates increased and steepened substantially between spring 2000 and 2002, rising about 17% in the lowest tier to about 76% in the highest tier. They then fell and flattened between 2002 and 2004, offsetting about half to three-quarters of the increase in the prior two years. But rates again increased and steepened substantially again between 2004 and 2006 by about 3% in the lowest two tiers to about 83% in the highest two tiers. Thus, these four time periods offer three substantial rate changes for examination, two significant increases and one moderate decrease.[31]

It would be tempting to compare changes in the tariff structure with changes in same-household consumption to see if high-consuming households were responsive to the changes in marginal and average rates, while low consuming households that faced much smaller rate changes exhibit smaller variation in consumption. One would then expect to see a pattern of the higher consuming households cutting consumption more when the rates on

[31] Customer baselines also changed slightly between 2002 and 2004. I account for these changes in the price schedules used in the analysis.

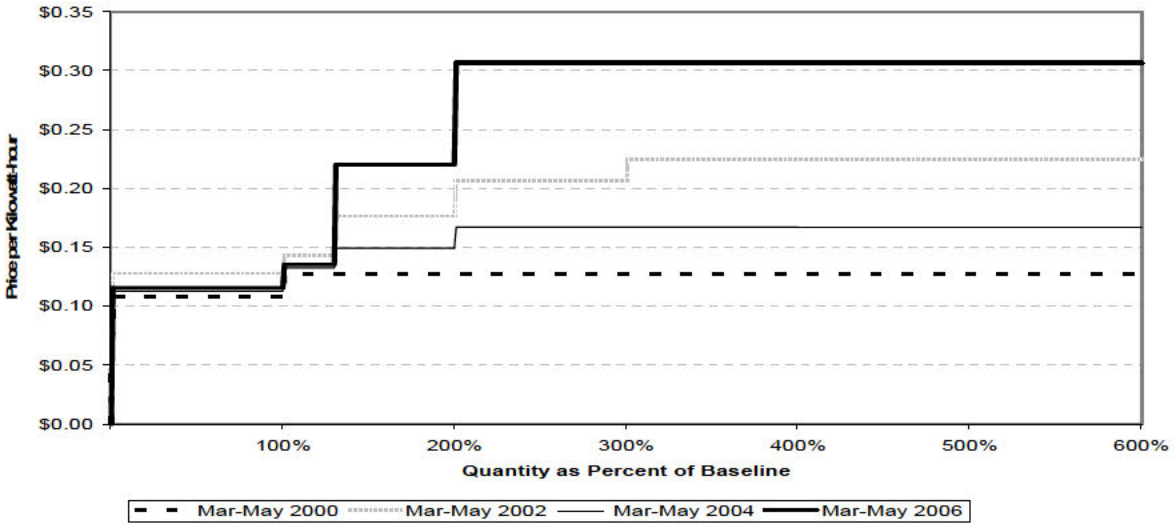

Figure 8: SCE Residential Tariff for March-May at Two-Year Intervals

higher tiers increase more (2000-2002 and 2004-2006) and increasing consumption more when the rates on higher tiers decline by more than on lower tiers (2002-2004). The difficulty with this approach to identifying elasticity is that there is natural mean reversion in household consumption over time. This occurs for at least two reasons. First, if households experience transitory consumption shocks – such as positive shocks from having visitors or negative shocks from being away from home – then any household observed at a more extreme part of the distribution will be likely to migrate back towards the center over time. Second, families that have children go through natural stages of consumption levels as they expand from no children to small children to teenagers, and (in most cases) back to no children at home. In fact, in these monthly time series consumption data, the household-level mean reversion is quite strong in all periods including those with no tariff change.[32] Separating the household mean reversion effect from the effect of rate changes is possible in theory, but fairly challenging in practice.

It seems quite likely, however, that neighborhoods experience much less fluctuation over time in the *distribution* of underlying demand functions across households living in the

[32] A (preliminary) regression at the premises level of change in consumption percentile within CBG consumption percentile in the previous period shows a strong tendency towards mean reversion, indicating for instance, that a household at the 95th percentile in one month would be expected to be slightly below the 85th percentile just one month later.

neighborhood. That is, the share of households in a neighborhood whose occupants are on vacation or hosting visitors in a given month – after controlling for seasonality – is not nearly as subject to the stochastic variation that leads to mean reversion in any one household. Likewise, over time neighborhoods are not nearly as subject to fluctuations in power consumption due to demographic changes as is any one household. Thus, one would expect the factors that cause mean reversion at the household level to have little effect on the *distribution* of usage across households in a neighborhood. On the assumption that the distribution of demand functions is constant over time – adjusting for overall shifts as described below – one could look for indication of price elasticity by examining how the distribution of quantity demanded across households in a neighborhood varies with the retail electricity tariff.

In particular, under much weaker conditions of consumer understanding of and response to prices than strict marginal price optimization, one would expect that price increases in tiers 3, 4 and 5 relative to tiers 1 and 2 would cause the variation in consumption across households in a neighborhood to narrow. For instance, even if consumers respond to average price or expected marginal price rather than marginal price, a change in the price perceived by heavier users relative to light users would still tend to change the consumption of heavier users relative to light users and narrow or widen the distributions of use. Because distributions of demand vary across areas, variation in this narrowing and its relationship to variation in changes in price may allow effective identification of price elasticity.

This argument about the distribution of consumption only applies if the neighborhood observed is stable. If there were a significant expansion or contraction of the housing stock within the sample in a neighborhood, then it would be much more difficult to infer the implication of the tariff change for the distribution of consumption quantities. To control for this, one could either examine only consumption on premises that existed at both the beginning and end of a 2-year period, or one could examine only neighborhoods with relatively little change in the housing stock. The results are quite consistent between these two approaches. I present here results based on comparisons of the same premises at the

beginning and end of the two-year period.[33] For premises to be included in the calculation of the consumption distribution parameters, they not only had to exist at the beginning and end of a two-year interval, but the customer at the address had to be on the standard residential tariff in both periods.[34]

To examine the properties of the distribution, it is also necessary to have sufficient premises to estimate those properties. I present here analysis where neighborhood designations are based on census block group (CBG) areas. An average CBG contains about 600 households in SCE's service territory. I include in the analysis only CBGs with at least 100 premises.[35]

Of course, factors other than tariff changes affect the distribution of electricity consumption across households in a CBG. Perhaps of most concern is income distribution changes. If the distribution of income is widening within CBGs, then a positive income elasticity of demand for electricity would be likely to widen the distribution of electricity consumption. While a snapshot of census data on income distribution is available, no reliable time series of income distribution changes at the CBG level is yet available for this time period.[36]

Under certain assumptions, the impact of tariff changes on the distribution of customer consumption can be used to estimate directly the price elasticity of demand. Again, a central underlying assumption is that while the demands of individual consumers are subject to shocks and lifecycle effects that lead to mean reversion at the customer level, the distribution of demand functions across a set of premises in a neighborhood is not subject to these systematic effects. Thus, the quantity demanded by the customer at

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[33] Premises are identified based on SCE's reported "premises number," which is unique to a building.

[34] This excluded not only premises that house customers on the CARE program (by far the largest component of the excluded premises), but also premises at which the customer was on some other special tariff, such as for electric heat or water heating, special medical equipment, or time-of-use pricing.

[35] I have also done this analysis at the zip code level, which reduces the number of observations by slightly more than 90%, and found very consistent results, though with larger standard errors.

[36] Even if such data were available, correcting for income distribution changes and their impact on the relative consumptions of different households within the distribution would require fairly strong structural assumptions (or estimates) about the income elasticity of electricity demand and how it varies across consumption levels. Even single point estimates of the income elasticity of demand vary by more than a factor of two in the literature, so the inference from such an approach would not be very reliable.

percentile n of the quantity distribution in CBG g at time t can be written:

$$\ln Q_{ngt} = \alpha_0 + \alpha_1 \cdot \ln P_{ngt}(Q_{ngt}) + \Omega X + \epsilon_{ngt}$$

where P is the relevant price to which the consumer is responding (marginal, expected marginal or average), which is a function of Q and is discussed further below, and X is a vector of the other factors that would shift the entire distribution of demand, including income, weather, and technology, as well as time and CBG fixed effects. Differencing this equation over t for a given n and g gives:

$$[\ln Q_{ngt_2} \quad \ln Q_{ngt_1}] = \alpha_{0'} + \alpha_1 \cdot [\ln P_{ngt_2}(Q_{ngt_2}) \quad \ln P_{ngt_1}(Q_{ngt_1})]$$

$$+\Omega[X_{ngt_2} \quad X_{ngt_1}] + [\epsilon_{ngt_2} \quad \epsilon_{ngt_1}] \qquad [5]$$

For example, the dependent variable might be the quantity change from 2000 to 2002 at the 75th percentile of the distribution. In differencing the equation, the time-invariant CBG fixed effect is eliminated. Any change in the time fixed effects is absorbed by retaining the constant term, which is now called $\alpha_{0'}$. Any factor in X, however, that changes between the two time periods will remain.

The data provide multiple observations in a time period within the same CBG during a month: the different points along the distribution of quantity demanded. For this analysis I use five observations, at the 10th, 25th, 50th, 75th, and 90th percentiles, in each CBG-month. These observations have different price changes due to the changes in the increasing-block structure, but they likely have similar changes in X variables, such as weather or technology. Estimation with multiple observations for each CBG and CBG-month fixed effects *in the differenced equation* would then eliminate X factors that changed between $t = 1$ and $t = 2$, but experienced the same change for all customers in the CBG.

Other factors in ΩX will remain, however, if changes in a variable that is part of X are different at different points in the distribution or if Ω varies along the distribution. For instance, if income grew between 2000 and 2002, but it systematically grew by more for households at the upper end of the electricity distribution, then the differencing would not cause the bracketed X term in [5] to be zero. Alternatively, even if income grew at the same rate at all points of the distribution, if the income elasticity of demand differs

systematically along the distribution, then the Ω would need a n subscript and differencing would not eliminate the term because the uniform growth in income would have differential impacts on the 75th than on the 25th percentile consumption level.

For now, I assume that all factors not eliminated by the time differencing or absorbed by the CBG-month fixed effects are captured by month-percentile fixed effects. For instance, if the weather in March 2002 was substantially colder than in March 2000 that might increase all customer demand, but might do so more (proportionally) for the 90th percentile of the demand distribution than the 10th percentile. As long as the proportional difference in the effect of this weather change on the 90th versus 10th percentile is uniform across all CBGs within a month it will be absorbed by a month-percentile fixed effect.

Still, a bias will remain if the relative shift of 90th versus 10th percentile change in demand differs across CBGs and that difference is correlated with the relative price change faced by customers in the 90th versus 10th percentile demand across CBGs. One possible way this could happen is if, for instance, the level of consumption at different percentiles (which is clearly correlated with the change in price) differs across CBGs in a way that is correlated with income *and* differences in income changes at different income levels (a widening of the income distribution, for example) are changing the relative electricity demand of 90th versus 10th percentile consumers. To address this possible bias, I also estimate demand allowing the month-percentile effects to vary with income levels across the CBGs.[37]

Equation [5] has price on the right-hand side, but the earlier analysis of consumer demand bunching suggests that a strict implementation of consumer optimization on marginal price would be difficult to justify. I pursue each of the theories discussed earlier. The first is to follow the literature, despite the evidence from the previous section, and assume that consumers were responding to the *ex post* observed marginal price. The second approach is to assume that consumers respond to the average price associated with the *ex post* observed consumption quantity. The third is to assume that consumers plan their consumption based on expected marginal price as described earlier and that the *ex post* observed con-

[37] Finally, of course, the linear in logs (constant elasticity) functional form is an important maintained assumption in the statistical inference.

sumption quantity is the mean of the distribution plus a mean-zero orthogonal error.

Regardless of which price measure is used, it is endogenous. Price changes with consumption, so failure to account for the endogeneity will impart a positive bias to price elasticity estimates, because a customer with a positive demand shock will also face a higher price. In addition, the price to which the consumer is responding is likely measured with error even under the maintained hypothesis that the form of the price I am assuming is correct. This is because price (in any of the hypothesized forms) is a function of quantity and quantity is uncertain.[38]

To address these issues in the differenced equation, I create an instrument that is the difference in price at the quantity consumed by the observed percentile in the distribution in the earlier period. For instance, for the 75th percentile observation in a given CBG, the price change would be the $[\ln P_{ngt_2}(Q_{ngt_2}) \quad \ln P_{ngt_1}(Q_{ngt_1})]$, so the price change would be positively correlated with any quantity shock due to the upward slope of the price schedule. But taking the price change at a fixed quantity, $[\ln P_{ngt_2}(Q_{ngt_1}) \quad \ln P_{ngt_1}(Q_{ngt_1})]$ would not exhibit that correlation, because both price observations are based on the same quantity, which is drawn from the pre-change period, so this is likely to be a valid instrument.[39]

Thus, the equation I estimate is

$$\begin{aligned}[\ln Q_{ngt_2} \quad \ln Q_{ngt_1}] &= \alpha_{0'} + \alpha_1 \cdot [\ln P_{ngt_2}(Q_{ngt_2}) \quad \ln P_{ngt_1}(Q_{ngt_1})] \\ &+ \sum_{g=1}^{G} \gamma_{1g} CBG_g Mar + \gamma_{2g} CBG_g Apr + \gamma_{3g} CBG_g May \\ &+ \sum_{n=25,50,75,90} \delta_{1n} Mar_n + \delta_{2n} Apr_n + \delta_{3n} May_n + \epsilon_{ng} \qquad [6]\end{aligned}$$

where CBG_g is an indicator variable for an observation in census block group g, Mar, Apr and May are indicator variables for observations in each month, n still indexes the different percentile observations, and Mar_n is an indicator variable for an observation on

[38] I do assume that the changes in the price structure are exogenous. Regulators changed rates over the years to meet revenue shortfalls or surpluses that would be very hard to tie to demand fluctuations at all, let alone to fluctuations in the relative demand of different size consumers.

[39] Failure to instrument for price does indeed yield the expected endogeneity bias. All estimated price elasticities are positive and significant. This probably suggests that the endogeneity bias is more of an issue in practice than the attenuation bias that results from measuing P with error.

percentile n in March, and likewise for Apr_n and May_n. The fixed effects for the 10th percentile observations are absorbed by the CBG-month fixed effects.

The results are shown in the top of table 3 using expected marginal price as the explanatory price variable. The number of observations differs slightly across the three time periods as some CBGs have sufficient qualifying premises to be included in some of the two-year intervals but not others. The downward trend in the number of included CBGs is due to the growth in the CARE program. Standard errors are clustered at the CBG level so they are not artificially depressed by the correlation across March/April/May observations or use of multiple different percentile observations in the same CBG. These results do not account for spatial correlation across neighboring CBGs which is no doubt also present, but clustering on larger spatial groups of CBGs – reducing the number of clusters by a factor of 10 – increases the standards errors only slightly.

The results suggest that the elasticity of demand with respect to a change in the expected marginal price was about -0.17 between 2000 and 2002, about -0.15 between 2002 and 2004, and about -0.12 between 2004 and 2006. Recall the first and third of these periods saw substantial price increases and the second saw moderate price decreases. The standard errors are quite small. The comparable estimated elasticities using average price and marginal price as the explanatory price variable are in the two rows below the regression (with month-percentile fixed effects not reported). Estimated elasticity with respect to marginal price is substantially smaller and estimated elasticity with respect to average price is substantially larger. The latter result is not surprising because average price varies less than expected marginal price.

Nonetheless, the estimates may not be as stable as either the small range of elasticities or the small standard errors would suggest. Equation [6] constrains the elasticity to be the same across months. In the lower panel of the table, I present the unconstrained elasticity estimates. These alternative specifications suggest that the estimates for the middle period, 2002-2004, are not very stable, possibly due to the comparatively small change in prices that occurred over this period.

The monthly elasticity estimates for the 2000-2002 and 2004-2006 periods exhibit a fairly clear pattern of lower elasticity in March, increasing into April and May. In nearly all cases

Dependent Variable: $\ln(Q_{ngt2}) - \ln(Q_{ngt1})$

Period	**2000-2002 Change**			**2002-2004 Change**			**2004-2006 Change**		
$\ln(E[MargP_{ngt2}])-\ln(E[MargP_{ngt1}])$	-0.1722	(0.0077)	***	-0.1489	(0.0276)	***	-0.1156	(0.0060)	***
Mar-25	-0.0056	(0.0008)	***	0.0098	(0.0009)	***	0.0254	(0.0010)	***
Mar-50	0.0023	(0.0012)	*	0.0155	(0.0012)	***	0.0559	(0.0018)	***
Mar-75	0.0146	(0.0019)	***	0.0158	(0.0021)	***	0.0868	(0.0028)	***
Mar-90	0.0225	(0.0026)	***	0.0158	(0.0030)	***	0.1051	(0.0034)	***
Apr-25	0.0019	(0.0008)	**	0.0069	(0.0009)	***	0.0240	(0.0010)	***
Apr-50	0.0116	(0.0011)	***	0.0128	(0.0014)	***	0.0497	(0.0017)	***
Apr-75	0.0259	(0.0018)	***	0.0135	(0.0022)	***	0.0762	(0.0027)	***
Apr-90	0.0345	(0.0025)	***	0.0141	(0.0031)	***	0.0928	(0.0034)	***
May-25	-0.0056	(0.0008)	***	0.0255	(0.0009)	***	0.0049	(0.0010)	***
May-50	-0.0015	(0.0011)		0.0448	(0.0010)	***	0.0170	(0.0015)	***
May-75	0.0094	(0.0018)	***	0.0527	(0.0018)	***	0.0343	(0.0025)	***
May-90	0.0160	(0.0025)	***	0.0562	(0.0029)	***	0.0450	(0.0032)	***
Constant	-0.0243	(0.0013)	***	0.0486	(0.0032)	***	0.0055	(0.0007)	***
Number of Observations		103730			100180			96585	
Nubmer of CBGs		7022			6763			6574	
$\ln(AvgP_{ngt2}) - \ln(AvgP_{ngt1})$	-0.1990	(0.0131)	***	-0.4133	(0.0426)	***	-0.1835	(0.0091)	***
$\ln(MargP_{ngt2}) - \ln(MargP_{ngt1})$	-0.0946	(0.0049)	***	-0.0382	(0.0074)	***	-0.0736	(0.0042)	***

Elasticity Estimates Unconstrained Across Months

Expected Marginal Price: $\ln(E[MargP_{ngt2}])-\ln(E[MargP_{ngt1}])$									
March	-0.1126	(0.0102)	***	0.0878	(0.0283)	***	-0.0764	(0.0074)	***
April	-0.1876	(0.0101)	***	-0.4664	(0.0488)	***	-0.1123	(0.0080)	***
May	-0.2103	(0.0089)	***	-0.1615	(0.0324)	***	-0.1597	(0.0074)	***
Average Price: $\ln(AvgP_{ngt2}) - \ln(AvgP_{ngt1})$									
March	-0.0708	(0.0181)	***	0.0153	(0.0512)		-0.1429	(0.0122)	***
April	-0.2566	(0.0166)	***	-0.9571	(0.0627)	***	-0.2169	(0.0116)	***
May	-0.2635	(0.0159)	***	-0.4065	(0.0572)	***	-0.1890	(0.0113)	***
Marginal Price: $\ln(MargP_{ngt2}) - \ln(MargP_{ngt1})$									
March	-0.0521	(0.0071)	***	0.0054	(0.0098)		-0.0467	(0.0052)	***
April	-0.1008	(0.0064)	***	-0.0726	(0.0101)	***	-0.0724	(0.0058)	***
May	-0.1268	(0.0064)	***	-0.0434	(0.0104)	***	-0.1088	(0.0063)	***

Census Block Group fixed effects not reported
IV estimation with price variables endogeous. Standard errors in parentheses.
***=significant at 1% **=significant at 5% *=significant at 10%

Table 3: Estimation of Demand Elasticity with Alternative Measures of Price (equation [6])

the results from using the expected marginal price are bracketed by elasticity estimates using marginal price and average price.

The percentile fixed effects are intended to capture systematic changes in the distribution due to factors in the ΩX term that affect different parts of the distribution differently. Although it is not dictated by theory, one might expect that these effects would likely be monotonic along the distribution. For instance, if cold weather increased consumption, but did so proportionally more for heavy electricity users, then a change in weather between years would be reflected in a monotonic change in the month-percentile fixed effects as one looks at higher percentiles for a given month. So, it is reassuring that this monotonic pattern (with the 10th percentile effect omitted and implicitly equal to zero) is evident in nearly all of the month-percentile fixed effects.

The estimated equation [6] for which the results are presented in tables 2 and 3 is premised on the assumption that the exogenous relative shift of consumption at different percentiles in the CBGs does not differ across CBGs in a way that is correlated with price changes. The chief concern is that wealthier CBGs, or CBGs with wealthier upper percentiles in consumption, might see a larger (or smaller, but probably larger if income disparities are widening) relative shift out in the demand of those at the upper end of consumption distribution. To address this concern, I estimate an augmented version of equation [6]

$$\begin{aligned}[\ln Q_{ngt_2} \quad \ln Q_{ngt_1}] &= \alpha_{0'} + \alpha_1 \cdot [\ln P_{ngt_2}(Q_{ngt_2}) \quad \ln P_{ngt_1}(Q_{ngt_1})] \\ &+ \sum_{g=1}^{G} \gamma_{1g} CBG_g Mar + \gamma_{2g} CBG_g Apr + \gamma_{3g} CBG_g May \\ &+ \sum_{n=25,50,75,90} \delta_{1n} Mar_n + \delta_{2n} Apr_n + \delta_{3n} May_n + \epsilon_{ng} \\ &+ \sum_{n=25,50,75,90} \delta_{1n} Mar_n \cdot \ln medHHI_g + \delta_{2n} Apr_n \cdot \ln medHHI_g + \delta_{3n} May_n \cdot \ln medHHI_g + \epsilon_{ng}\end{aligned} \qquad [7]$$

where $\ln medHHI_g$ is the 2000 median household income for that census block group. Though these terms are jointly highly significant, they do not qualitatively change the elasticity estimates.[40]

[40] I also estimate [7] replacing median household income with the income for the corresponding percentile in the income distribution with the CBG, *e.g.*, , the 25th percentile income for the 25th percentile fixed CBG-month effects. These also were highly significant, but do not change the elasticity results.

Dependent Variable: $\ln(Q_{ngt2}) - \ln(Q_{ngt1})$

Period	**2000-2002 Change**				**2002-2004 Change**				**2004-2006 Change**			
Pairwise Inclusion of Price Variables												
$\ln(MargP_{ngt2}) - \ln(MargP_{ngt1})$	0.0737	(	0.0104)	***	-0.0085	(	0.0061)		0.0284	(	0.0114)	**
$\ln(E[MargP_{ngt2}])-\ln(E[MargP_{ngt1}])$	-0.2629	(	0.0162)	***	-0.1392	(	0.0287)	***	-0.1504	(	0.0158)	***
$\ln(MargP_{ngt2}) - \ln(MargP_{ngt1})$	-0.0825	(	0.0053)	***	-0.0071	(	0.0069)		-0.0396	(	0.0043)	***
$\ln(AvgP_{ngt2}) - \ln(AvgP_{ngt1})$	-0.0659	(	0.0138)	***	-0.3988	(	0.0418)	***	-0.1434	(	0.0095)	***
$\ln(AvgP_{ngt2}) - \ln(AvgP_{ngt1})$	0.0455	(	0.0143)	***	-0.4534	(	0.0707)	***	-0.1211	(	0.0089)	***
$\ln(E[MargP_{ngt2}])-\ln(E[MargP_{ngt1}])$	-0.1865	(	0.0089)	***	0.0251	(	0.0448)		-0.0830	(	0.0059)	***
Inclusion of All Three Price Variables												
$\ln(MargP_{ngt2}) - \ln(MargP_{ngt1})$	0.0778	(	0.0104)	***	-0.0107	(	0.0060)	*	0.0694	(	0.0116)	***
$\ln(AvgP_{ngt2}) - \ln(AvgP_{ngt1})$	0.0459	(	0.0143)	***	-0.4468	(	0.0705)	***	-0.1291	(	0.0092)	***
$\ln(E[MargP_{ngt2}])-\ln(E[MargP_{ngt1}])$	-0.2825	(	0.0172)	***	0.0347	(	0.0457)		-0.1657	(	0.0158)	***

Census Block Group and Month-Percentile fixed effects not reported
IV estimation with price variables endogeous. Standard errors in parentheses.
***=significant at 1% **=significant at 5% *=significant at 10%

Table 4: Estimation of Demand Including Multiple Measures of Price

To What Price Do Consumers Respond?

With these somewhat different results using different measures of price, a natural question to ask is which better represents consumer behavior. The three measures are highly correlated with one another, but they do clearly differ substantially in the neighborhood of the jumps in the increasing-block price schedule.

Table 4 presents regressions in which multiple measures of price are included as explanatory variables. The results reinforce the impression that observed marginal price is not the best indicator of the effect of price on consumer demand. The top panel shows that when expected marginal price and observed marginal price are both included in the regression, expected marginal price is negative, significant and of plausible magnitude in all three periods while observed marginal price is estimated to have an incremental impact that is positive and significant in the first and last period, and insignificant in the middle period.

The second panel shows that observed marginal price has a more plausible negative incremental impact in a regression with *ex post* observed average price, at least in the first and last period. Average price, however, remains consistently negative and significant in all three periods. The third panel indicates that expected marginal price is less clearly dominant against average price in explaining consumer response. It is significant in the first and last period, but in the middle period quantity response seems to be better modeled – within this constant-elasticity functional form – as a function of average price. The bottom panel of table 4 shows the results from regressions with all three price measures. It reinforces the conclusion that observed marginal price is the least useful of the three measures in gauging consumer response. With all three regressors, observed marginal price is positive and significant in the first and last period, while it is negative, small and significant at the 8% level in the middle period.

Obviously, none of these is the single "correct" measure of price, and each is a slightly nonlinear function of the others. There is a range of ways in which consumers perceive and process price information given their constraints in information, cognition and attention. Furthermore, the constant elasticity functional form is in itself a significant restriction on the way in which price affects consumption quantity. Still, plausible modeling of consumer behavior suggests that consumers are likely to be responding to less-discrete perceived price schedules and empirical support for that conclusion is fairly robust.

VIII. Conclusion

Over the last 40 years, as focus on U.S. energy policy has waxed and waned, there has been intermittently keen interest in the price elasticity of demand for electricity. With the controversies that have followed electric industry restructuring and rising concerns about climate change, attention to the issue has grown again recently. Unfortunately, limited data availability has forced some research to impose strong assumptions on consumer demand behavior, particularly in attempting to infer price elasticity from cross-sectional data under increasing-block pricing. A number of papers have assumed that consumers choose quantity demanded for a period based on the marginal price that they end up facing for the period.

I have argued that even under the most vigilant daily or hourly optimizing behavior,

consumers under increasing-block pricing would not choose consumption based on the *ex post* observed price for the billing period, because exogenous shocks to demand would make it impossible for a consumer to know throughout the period what that marginal price would be. In a more plausible view of behavior, customers do not monitor their consumption closely within billing periods, but instead respond to the price schedule and the possible distribution of their demand states by establishing rules about behavior. I show that this results in consumers equating their expected marginal value of consumption with a smoothly increasing expected marginal price function, one that would not be consistent with discrete-continuous choice modeling of demand. Of course, even the constrained-optimization behavior that I posit may go way beyond the typical customer's awareness of electricity price, in which case one might expect to observe consumers responding to overall changes in the average price they face, but nothing more sophisticated than that.

If consumers were able to optimize precisely against the end-of-period marginal price they face, a straightforward application of consumer theory suggests that one would expect to see a bunching of observed quantities around the steps in the increasing-block pricing schedule. I simulate the impact that the steps should have on the observed quantity distribution and show that they are quite large, even under fairly conservative assumptions. Actual empirical distributions of residential demand quantity, however, does not exhibit such bunching.

Attempts to estimate demand elasticity from a static price schedule are generally a response to the limited availability of data that include other price variation. Luckily, intertemporal price variation do exist in the billing data from Southern California Edison that I have been able to analyze. Substantial changes in the residential price schedule over the 2000-2006 time period enable me to estimate the response to price changes and to evaluate how well different measures of price perform in this estimation. All three measures of price that I investigate – observed marginal price, a measure of expected marginal price, and average price – are estimated to have a negative and significant impact on consumption. The estimated impact of observed marginal price is consistently between 0 and -0.12. These should be interpreted as medium to long run elasticities, responding to changes in the price schedule that occured at least a few months earlier. As such, they are smaller than comparable elasticities than have been reported in previous studies

using the DCC approach. The size of the SCE dataset also permits me to compare the appropriateness of the price variables by estimating demand with more than one of the price variables even though they are highly co-linear. The results suggest that marginal price is a less revealing indicator of consumer response to changes than are either of the other two measures.

Overall, the results indicate that among the distribution of consumers there are many who likely respond to little more than average price information, while others either consciously or unconsciously are aware of – and show some response to – the expected marginal price that they are likely to face. The estimated level of response is not as robust over time as one might hope for, but it appears to be in the elasticity range of -0.1 to -0.2 for expected marginal price and somewhat higher for average price, a measure that itself varies less.

It is unclear how much one can generalize from this result to the use of increasing-block pricing in general. It is quite clear from studies of cellphone pricing and marginal income taxes that consumer understanding of non-linear price schedules varies widely. Such understanding seems amenable to education campaigns, though such approaches will still run up against attention and cognition constraints that are likely significant for the vast majority of consumers who don't think like economists, and even for many who do.

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Short Run Income Elasticity of Demand for Residential Electricity Using Consumer Expenditure Survey Data*

*E. Raphael Branch***

This study provides information on the relationship between income and electricity consumption based on the Consumer Expenditure Interview Survey (CE) of the Bureau of Labor Statistics, U.S. Department of Labor. The income elasticity of short run demand for residential electricity is estimated using household panel data for homeowners. The CE is rich in its coverage of household characteristic data, housing characteristic data, and appliance inventory data. This makes it possible to model electricity demand across areas in the United States more comprehensively than has been done in a number of earlier studies. The results, obtained using a generalized least squares estimator (GLS), include an income elasticity of demand for electricity of 0.23 and a price elasticity of -0.20. The GLS estimator is used because OLS estimates are inefficient due to the correlation of the errors which arises from the use of panel data.

INTRODUCTION

For the first time, detailed data on the quantity of residential electricity from the Consumer Expenditure Survey (CE) of the U.S. Department of Labor, Bureau of Labor Statistics are used to estimate the effects of the determinants of the demand for residential electricity. The analysis is limited to homeowner households because electricity consumption data are not available from the CE

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for renters whose utility costs are included in their rent; and this presents empirical considerations which are beyond the scope of this study. CE data on the quantity of electricity consumed are collected continuously, as part of the collection of expenditure data, and therefore the potential exists to use the CE for periodic analysis of electricity demand. The purpose of this study is to explore this potential. The production of results within the range of selected estimates suggests that the CE, which is designed to collect expenditure data, has broader applications than are currently in use.[1]

The demand for electricity is modeled as a function of the utilization of appliances and the potential of the appliance stock to draw electrical power. A similar approach has been used by Hsiao and Mountain (1985) to estimate income elasticity of demand from Canadian provincial panel data using a categorical income variable. This study of U.S. residential electricity demand is national in scope and uses a continuous income proxy, total expenditures, as a measure of permanent income. The income elasticity is expected to be positive and low.

THE MODEL

Definition of Residential Electricity Demand

The demand for residential electricity is derived from the demand for services, such as heating, cooling, and cooking, which are produced by using electric appliances. Therefore, the use of appliances and the stock of appliances are major determinants of the demand for residential electricity. In the short run, the intensity with which consumers use electric appliances depends on their income, the price of electricity, housing unit structure, demographic characteristics, seasonal variation, and weather. Total annual expenditures are used as the proxy for permanent income, consistent with the permanent income hypothesis (Friedman 1957; Houthakker and Taylor 1970). The short run effect of changes in the price of electricity is a change in the quantity of electricity consumed, a movement along the household's demand curve. The use of average price as a determinant of electricity consumption is based on the assumption that the consumer responds to the price which he perceives from his total electricity bill (Wilder and Willenborg, 1975; Shin, 1985).

1. The Consumer Expenditure survey (CE) focuses on obtaining household expenditures by demographic groups. It is the only survey of its kind and is used in a variety of research projects by government, business, labor, and academic analysts. The data are collected continuously and annual estimates of consumer expenditures, income, and demographic characteristics per household are published annually. The sample for this study includes 4,154 monthly observations which represent 1,012 households.

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It is assumed that a year is not enough time to convert an electricity-using appliance to one which uses an alternative energy source in response to price increases; and therefore, the appliance stock is assumed to be fixed in the short run (Fisher and Kaysen 1962; Taylor 1975). This definition is also referred to as the conditional demand for residential electricity because the short run is defined by the condition that the appliance stock is fixed (Hsiao and Mountain 1985).[2]

Theoretical Model

Electricity demand is modeled as follows:

$$Q = f(Y, P, H, D, S, W, A) + e \tag{1}$$

where Q is the monthly quantity of electricity in kilowatt hours, Y is annual income per household, P is the monthly area price of electricity, H is housing unit structure, D represents demographic characteristics, S represents the seasonal dummy variables, W represents weather variables, A represents heating equipment types and electricity-using appliance dummy variables, and e is a random error term.

Empirical Model

Equation (1) is assumed to take a double log form as follows:

$$\begin{aligned} \ln Q_{it} &= \alpha + \beta \ln Y_i + \gamma \ln P_{jt} + \delta H_i + \sum_{k=1}^{s} \zeta_k D_{ikt} + \sum_{m=1}^{u} \theta_m S_{mt} \\ &\quad + \sum_{n=1}^{v} \lambda_n A_{1in} W_{jnt} + \sum_{o=1}^{w} \mu_o A_{2io} + e_{it} \\ e_{it} &= d_i + u_{it} \end{aligned} \tag{2}$$

where α is the intercept; β, γ, δ, ζ_k, θ_m, λ_n, and μ_o are coefficients representing exogenous effects on electricity consumption. The error term, e_{it}, is composed

2. Another concept of the conditional demand for residential electricity is that the total consumption of electricity by a household (whole house consumption) is directly related to the stock of electric appliances and the electricity consumption of specific appliances owned by the household. This approach is the basis of Conditional Demand Analysis (CDA), a technique used to estimate the consumption of specific electric appliances, referred to as end-use consumption. The present study does not analyze end-use consumption. For a detailed discussion of the CDA method see Parti and Parti (1980) and Cambridge Systematics Inc., and Regional Economic Research Inc. (1989).

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of a household-specific error component, d_i, and a random noise term, u_{it}, with means of zero and variances σ_d^2 and σ^2, respectively.

In the definitions below, dummy variables have a value of one if the household has the determinant and zero otherwise:

Y_i = permanent nominal income proxied by total expenditures for a quarter in 1985, averaged over the quarters that household i is in the study sample.

P_{jt} = average price of electricity for area j in month t. This price is used under the assumption that households face the same price level in the area where they live.[3]

H_i = a housing structure variable for household i, consisting of the number of rooms.

D_{ikt} = household i's demographic characteristics, k, in month t. These include discrete variables for age of reference person and household size; and dummy variables for sex, race, marital status of the reference person, presence of family members over age 65, presence of children under age 6, and region of residence ($s=10$). Regional dummies are included for the Northeast, Midwest, and South. (The West is omitted).

S_{mt} = the seasonal dummy variables, m, for month t; for summer, winter, and fall ($u=3$). (The Spring is omitted).

$A_{iln}W_{jnt}$ = weather-related home heating and air conditioning appliances (A_l) for household i, interacted with two weather variables (W) for area j and month t ($v=3$). The variables include electric space heating (A_{i1}) interacted with heating degree days (W_{jlt}), air conditioning (A_{i2}) interacted with cooling degree days

3. The Consumer Price Index (CPI) of the Bureau of Labor Statistics is the source for price data. Monthly average prices for 25 CPI market basket areas are matched to CE areas. The prices are lagged one month in order to account for differences between CPI collection and utility company billing periods. The prices are not deflated because it would require inter-area price indexes which are not available. (See Bureau of Labor Statistics 1980, 1983). Area information is not on the CE public use tape due to confidentiality restrictions.

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(W_{j2i}), and central air conditioning (A_{13}) interacted with cooling degree days (W_{j2i}).[4]

A_{2io} = the dummy variables for household i's electricity using appliances, including eight major household appliances and nine furnace equipment types ($w=17$). The appliances include electric water heater, electric oven, microwave oven, freezer, clothes dryer, built-in dishwasher, portable dishwasher, and garbage disposal.

The income elasticity η is defined as $\partial \ln Q / \partial \ln Y$ which equals β from equation (2). In this study the income elasticity is expected to be greater than zero but less than 0.5. The income elasticity is expected to be small because this is a short run model and the effects of income are conditioned on the stock of appliances and housing characteristics. Without these controls, we would expect the income elasticity to be larger.

ECONOMETRIC METHODS

Usimg monthly observations for households presents the econometric problem of pooling time-series and panel data (Maddala 1977). When panel data are used, the error terms for each household across the months for which it is in the sample are correlated. Using an OLS estimator would result in inefficient coefficient estimates and bias in the usual standard errors from OLS. Therefore, a generalized least squares estimator (GLS) is used to correct for correlation of the error term. The use of GLS as the maximum likelihood estimator is based on the assumption that the errors follow a variance components model and are distributed joint-normally. The GLS estimator uses an estimated variance-covariance matrix (because the generalized matrix is not known) to obtain more efficient estimates of the coefficients (Kennedy 1985).[5]

4. Monthly estimates of 1985 heating and cooling degree days are taken from local climate data of the National Oceanic and Atmospheric Administration (1990). These data are measures of differences in temperature below and above 65 degrees Fahrenheit (18.3 degrees Celsius).

5. Ordinary least squares stepwise, forward selection procedure was used to assist in selection of appropriate regressors from the large number of variables available from the CE survey. Details about the OLS regression are not reported here but are available on request from the Bureau of Labor Statistics Division of Consumer Expenditure Surveys.

GLS estimation has been accomplished using SAS PROC MATRIX (SAS Institute 1982). The computer program is designed to estimate regression parameters by the Maximum Likelihood (ML) method using data which has been transformed, in the manner described in Fuller and Battese (1973), to construct an error components model. For a detailed discussion of the underlying theory, calculation methods, and computer program, see Moulton (1988). The difference in logs is taken as the percentage difference for the log variables.

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ESTIMATION RESULTS

The results of the GLS estimation are shown in Table 1. Because the regression equation is semi-logarithmic, the percentage effects are derived by exponential transformation of the coefficients (Halvorsen et al., 1980). The GLS estimate (standard error in parentheses) of income elasticity is, 0.23 (0.03) with a p-value of less than 0.0001. The estimated price elasticity is -0.20 (0.05) with a p-value of 0.0002. Other selected GLS results from the study are discussed below.

Demographic characteristics and housing unit size. The results indicate that family size, age of reference person, marital status of reference person, and housing unit size have a significant effect on electricity consumption. Family size has the greatest effect of the demographic characteristics, followed by marital status, then age. When controlling for other utilization variables and the stock of appliances, on average, the number of kWh used per month is 8% higher per additional household member. For example, a five-person household is likely to consume 26% more electricity than a two-person household. Households with married reference persons average 7% higher electricity use than other types of households. The results for age of reference person show that electricity consumption increases with age by 0.3% per year of age. For example, households with reference persons of age 65 would average about 9% higher electricity consumption than those with a reference person of age 35. When controlling for other factors in the model, the effect of the size of the housing unit on electricity use is to increase consumption by 4% for each additional room.

Home heating and cooling. The results show that when controlling for income, price, housing unit size, demographic factors, and major household appliances, households with electricity as the main source for home heating have 0.12% higher electricity consumption per heating degree day than households with other sources for heating. To translate the interaction variable coefficient into an average percent change in electricity consumption, heating degree day data for a specific area are needed. The following example uses data for the New York sample area: The average number of monthly heating degree days during the winter of 1985 for New York is 960. By multiplying the coefficient times the heating degree days and making the exponential transformation, this translates to 205% higher electricity use per winter month for New Yorkers with electric home heating compared to those without it.

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Table 1. Results of Estimating Short Run Demand for Residential Electricity

Independent Variable	Generalized least squares[a]		
	Coeff.	Standard Error	P-value
Intercept	2.4600	0.3237	[b]
Log total expenditure	0.2343	0.0323	[b]
Log average price	-0.2045	0.0544	0.0002
Number of rooms	0.0406	0.0094	[b]
Household size	0.0782	0.0108	[b]
Age of reference person	0.0030	0.0011	0.0053
Marital status of reference person	0.0700	0.0367	0.0565
Northeast dummy	-0.0711	0.0537	0.1857
Midwest dummy	0.0199	0.0388	0.6071
South dummy	0.0390	0.0432	0.3663
Winter dummy	0.1413	0.0178	[b]
Summer dummy	0.0433	0.0196	0.0273
Fall dummy	0.0556	0.0186	0.0028
Electric heat dummy and heating degree days	0.0012	0.0001	[b]
Air conditioning dummy and cooling degree days	0.0010	0.0001	[b]
Central air dummy and cooling degree days	0.0007	0.0001	[b]
Electric water heater dummy	0.3649	0.0401	[b]
Central forced air furnace dummy	0.1215	0.0357	0.0007
Gravity forced air dummy	0.1514	0.1259	0.2290
Wall furnace with heat pump dummy	0.1655	0.1488	0.2661
Central system with heat pump dummy	-0.0178	0.1086	0.8700
Room heater with flue dummy	0.1983	0.1072	0.0644
Room heater without flue dummy	0.1261	0.1119	0.2598
Electric stove dummy	0.1384	0.0312	[b]
Microwave oven dummy	0.0295	0.0319	0.3547
Freezer dummy	0.2348	0.0307	[b]
Clothes dryer dummy	0.1314	0.0420	0.0017
Built-in dishwasher dummy	0.0883	0.0503	0.0788
Portable dishwasher dummy	0.0388	0.0387	0.3157
Garbage disposal dummy	-0.0199	0.0355	0.5756

Note: [a]Residual variance = 0.137; group variance = 0.151; log likelihood = -2550.55.
[b]P-value is less than 0.0001.

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It is estimated that when controlling for other factors, households with air conditioning (including central air) have, on average, 0.17% higher electricity consumption per cooling degree day than households without air conditioning. The percentage effect is obtained in the same manner as for home heating. For example, New York had an average of 797 cooling degree days for the summer months in 1985. This translates to 294% higher electricity consumption per summer month than that of households without air conditioning.

Other major appliances. When electricity is used as the source for water heating, electricity consumption is about 44% higher than when other water heating sources such as natural gas are used. On average, households with freezers are likely to have 26% higher electricity consumption than those without them. This translates to an estimated difference of about 1660 kWh per year. Electric ovens, electric clothes dryers, and built-in electric dishwashers also contribute significantly to electricity consumption. When these items are present, electricity consumption increases an average of 15%, 14%, and 9% respectively. However, the results show that microwave ovens, portable dishwashers, and garbage disposals did not have a significant effect on electricity consumption.

Combined effects. The home heating and air conditioning effects together with the other electric appliance effects provide an estimate of differences between households with all electric homes and those who use alternative fuel sources. For example, in New York where the annual average number of heating degree days in 1985 was 381 and the number of annual average cooling degree days was 98.5, the annual total effect of using electricity for forced-air space heating, central air conditioning, water heating, an electric oven, freezer, clothes dryer, and built-in dishwasher is a 450% increase in electricity consumption over households without this set of equipment.

COMPARISON AND ANALYSIS

Income and price elasticities from this study are compared with results from selected short run residential electricity demand studies and are within reasonable range of the selected estimates. (See Table 2). Some of the differences between the estimates of income and price elasticity in this study and the selected ones are due to differences in methodology and data, as shown in Table 2. The income elasticity of 0.23 is closest to the estimate of 0.20 obtained by Barnes, Gillingham, and Hagemann (1981) using earlier CE data with different methods. The income elasticity from this study is higher than estimates of 0.17 found in Hsiao and Mountain (1985) and Shin (1985), and 0.14 found in Houthakker (1980). In these studies, the income measure is different; Hsiao and Mountain (1985) analyze categorical income data and the other two studies

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Table 2. Selected Income and Price Elasticities

Study	Income Elasticity	Price Elasticity	Data Type	Price Type[a]	Income Measure	Reference Period	Method/ form[b]	Area
Present study	0.23	-0.20	Household monthly	AP	Total expenditures	1985	EC(GLS)/ML double log	National
Hsiao and Mountain (1985)	0.17	[c]	Household annual	[c]	Categorical	1980	Pseudo IV/ double log	Ontario Province
Shin (1985)	0.17	-0.14	Utility Annual	[d]	Real per capita	1960-80	LSDV/Koyck flow adjust. double log	Ohio State
Barnes, Gillingham, and Hagemann (1981)	0.20	-0.55	Household monthly	MP	Real total expenditures	1972-73	IV semi-log	National
Houthakker (1980)	0.14	-0.11	State annual	MP	Real Per capita	1964-76	EC log/flow adjustment	National
Acton, Mitchell, and Mowill (1976)	0.40	-0.35	Small geographic area monthly	MP	Real mean	July 1972 to June 1974	Weighted OLS	Los Angeles County

Notes: [a]AP=average price; MP=marginal price.

[b]OLS=ordinary least squares; EC=error components; ML=maximum likelihood; IV=instrumental variables; LSDV=least squares with dummy variables.

[c]The price of electricity and the price index of all other goods chosen by the household are considered fixed.

[d]The perceived price specification is $MP_t(AP_t/MP_t)^k$, where k is a fixed price perception parameter.

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use real per capita income with more aggregated data. The 0.40 obtained by Acton, Mitchell, and Mowill (1976) who analyze small geographic area data, is much larger than the estimate in the present study. This study uses deflated mean income and addresses the appliance stock differently.

The price elasticity of the present study, -0.20, is higher than Shin's (1985) price elasticity of -0.14, and Houthakker's (1980) price elasticity of -0.11. The price elasticity obtained by Barnes, Gillingham, and Hagemann (1981) is -0.55, much higher than the present study; probably reflecting the differences in the treatment of price and estimation methods.

SUMMARY

A GLS estimator of the short run demand for electricity has been derived by regressing the quantity of electricity (measured in kilowatt hours per month) on variables representing the utilization and stock of electric appliances. The study obtained an income elasticity of 0.23 using total expenditures as a measure of permanent income, and a price elasticity of -0.20. The results support the expectation that the relationship between income and the consumption of electricity is direct and fairly inelastic in the short run. In models where appliances are not controlled, income elasticity is likely to be much higher.

Substantial effects are estimated for electric home heating, cooling, and other electric appliances such as freezers, clothes dryers, and water heaters. The results also indicate that housing unit size and demographic characteristics (such as household size, age of reference person, and marital status) have significant effects on electricity consumption.

This study represents an expanded use of Consumer Expenditure Survey data of the Bureau of Labor Statistics beyond its traditional use in expenditure studies. It takes advantage of ancillary electricity quantity data collected while obtaining expenditure data. The results offer average effects across the United States which fall within the range of selected studies. This study gives a view of the potential for similar use of the CE for analysis of residential electricity consumption.

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The Capital Asset Pricing Model: Theory and Evidence

Eugene F. Fama and Kenneth R. French

The capital asset pricing model (CAPM) of William Sharpe (1964) and John Lintner (1965) marks the birth of asset pricing theory (resulting in a Nobel Prize for Sharpe in 1990). Four decades later, the CAPM is still widely used in applications, such as estimating the cost of capital for firms and evaluating the performance of managed portfolios. It is the centerpiece of MBA investment courses. Indeed, it is often the only asset pricing model taught in these courses.[1]

The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor—poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive "market portfolio" that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it

[1] Although every asset pricing model is a capital asset pricing model, the finance profession reserves the acronym CAPM for the specific model of Sharpe (1964), Lintner (1965) and Black (1972) discussed here. Thus, throughout the paper we refer to the Sharpe-Lintner-Black model as the CAPM.

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legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

We begin by outlining the logic of the CAPM, focusing on its predictions about risk and expected return. We then review the history of empirical work and what it says about shortcomings of the CAPM that pose challenges to be explained by alternative models.

The Logic of the CAPM

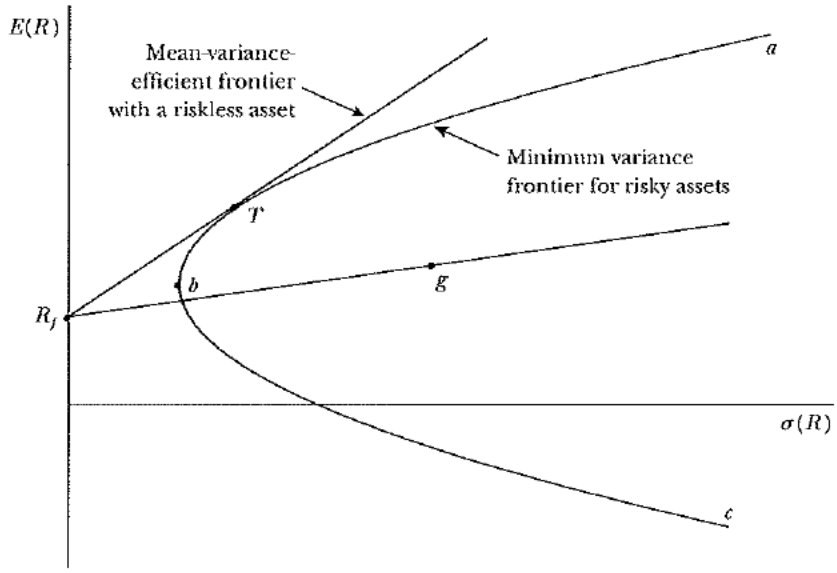
The CAPM builds on the model of portfolio choice developed by Harry Markowitz (1959). In Markowitz's model, an investor selects a portfolio at time $t-1$ that produces a stochastic return at t. The model assumes investors are risk averse and, when choosing among portfolios, they care only about the mean and variance of their one-period investment return. As a result, investors choose "mean-variance-efficient" portfolios, in the sense that the portfolios 1) minimize the variance of portfolio return, given expected return, and 2) maximize expected return, given variance. Thus, the Markowitz approach is often called a "mean-variance model."

The portfolio model provides an algebraic condition on asset weights in mean-variance-efficient portfolios. The CAPM turns this algebraic statement into a testable prediction about the relation between risk and expected return by identifying a portfolio that must be efficient if asset prices are to clear the market of all assets.

Sharpe (1964) and Lintner (1965) add two key assumptions to the Markowitz model to identify a portfolio that must be mean-variance-efficient. The first assumption is *complete agreement*: given market clearing asset prices at $t-1$, investors agree on the joint distribution of asset returns from $t-1$ to t. And this distribution is the true one—that is, it is the distribution from which the returns we use to test the model are drawn. The second assumption is that there is *borrowing and lending at a risk-free rate*, which is the same for all investors and does not depend on the amount borrowed or lent.

Figure 1 describes portfolio opportunities and tells the CAPM story. The horizontal axis shows portfolio risk, measured by the standard deviation of portfolio return; the vertical axis shows expected return. The curve *abc*, which is called the minimum variance frontier, traces combinations of expected return and risk for portfolios of risky assets that minimize return variance at different levels of expected return. (These portfolios do not include risk-free borrowing and lending.) The tradeoff between risk and expected return for minimum variance portfolios is apparent. For example, an investor who wants a high expected return, perhaps at point *a*, must accept high volatility. At point *T*, the investor can have an interme-

Figure 1
Investment Opportunities



diate expected return with lower volatility. If there is no risk-free borrowing or lending, only portfolios above b along abc are mean-variance-efficient, since these portfolios also maximize expected return, given their return variances.

Adding risk-free borrowing and lending turns the efficient set into a straight line. Consider a portfolio that invests the proportion x of portfolio funds in a risk-free security and $1 - x$ in some portfolio g. If all funds are invested in the risk-free security—that is, they are loaned at the risk-free rate of interest—the result is the point R_f in Figure 1, a portfolio with zero variance and a risk-free rate of return. Combinations of risk-free lending and positive investment in g plot on the straight line between R_f and g. Points to the right of g on the line represent borrowing at the risk-free rate, with the proceeds from the borrowing used to increase investment in portfolio g. In short, portfolios that combine risk-free lending or borrowing with some risky portfolio g plot along a straight line from R_f through g in Figure 1.[2]

[2] Formally, the return, expected return and standard deviation of return on portfolios of the risk-free asset f and a risky portfolio g vary with x, the proportion of portfolio funds invested in f, as

$$R_p = xR_f + (1 - x)R_g,$$

$$E(R_p) = xR_f + (1 - x)E(R_g),$$

$$\sigma(R_p) = (1 - x)\sigma(R_g),\ x \leq 1.0,$$

which together imply that the portfolios plot along the line from R_f through g in Figure 1.

To obtain the mean-variance-efficient portfolios available with risk-free borrowing and lending, one swings a line from R_f in Figure 1 up and to the left as far as possible, to the tangency portfolio T. We can then see that all efficient portfolios are combinations of the risk-free asset (either risk-free borrowing or lending) and a single risky tangency portfolio, T. This key result is Tobin's (1958) "separation theorem."

The punch line of the CAPM is now straightforward. With complete agreement about distributions of returns, all investors see the same opportunity set (Figure 1), and they combine the same risky tangency portfolio T with risk-free lending or borrowing. Since all investors hold the same portfolio T of risky assets, it must be the value-weight market portfolio of risky assets. Specifically, each risky asset's weight in the tangency portfolio, which we now call M (for the "market"), must be the total market value of all outstanding units of the asset divided by the total market value of all risky assets. In addition, the risk-free rate must be set (along with the prices of risky assets) to clear the market for risk-free borrowing and lending.

In short, the CAPM assumptions imply that the market portfolio M must be on the minimum variance frontier if the asset market is to clear. This means that the algebraic relation that holds for any minimum variance portfolio must hold for the market portfolio. Specifically, if there are N risky assets,

$$\text{(Minimum Variance Condition for } M) \quad E(R_i) = E(R_{ZM}) + [E(R_M) - E(R_{ZM})]\beta_{iM}, \; i = 1, \ldots, N.$$

In this equation, $E(R_i)$ is the expected return on asset i, and β_{iM}, the market beta of asset i, is the covariance of its return with the market return divided by the variance of the market return,

$$\text{(Market Beta)} \quad \beta_{iM} = \frac{\text{cov}(R_i, R_M)}{\sigma^2(R_M)}.$$

The first term on the right-hand side of the minimum variance condition, $E(R_{ZM})$, is the expected return on assets that have market betas equal to zero, which means their returns are uncorrelated with the market return. The second term is a risk premium—the market beta of asset i, β_{iM}, times the premium per unit of beta, which is the expected market return, $E(R_M)$, minus $E(R_{ZM})$.

Since the market beta of asset i is also the slope in the regression of its return on the market return, a common (and correct) interpretation of beta is that it measures the sensitivity of the asset's return to variation in the market return. But there is another interpretation of beta more in line with the spirit of the portfolio model that underlies the CAPM. The risk of the market portfolio, as measured by the variance of its return (the denominator of β_{iM}), is a weighted average of the covariance risks of the assets in M (the numerators of β_{iM} for different assets).

Thus, β_{iM} is the covariance risk of asset i in M measured relative to the average covariance risk of assets, which is just the variance of the market return.[3] In economic terms, β_{iM} is proportional to the risk each dollar invested in asset i contributes to the market portfolio.

The last step in the development of the Sharpe-Lintner model is to use the assumption of risk-free borrowing and lending to nail down $E(R_{ZM})$, the expected return on zero-beta assets. A risky asset's return is uncorrelated with the market return—its beta is zero—when the average of the asset's covariances with the returns on other assets just offsets the variance of the asset's return. Such a risky asset is riskless in the market portfolio in the sense that it contributes nothing to the variance of the market return.

When there is risk-free borrowing and lending, the expected return on assets that are uncorrelated with the market return, $E(R_{ZM})$, must equal the risk-free rate, R_f. The relation between expected return and beta then becomes the familiar Sharpe-Lintner CAPM equation,

$$\text{(Sharpe-Lintner CAPM)} \quad E(R_i) = R_f + [E(R_M) - R_f]\beta_{iM},\ i = 1, \ldots, N.$$

In words, the expected return on any asset i is the risk-free interest rate, R_f, plus a risk premium, which is the asset's market beta, β_{iM}, times the premium per unit of beta risk, $E(R_M) - R_f$.

Unrestricted risk-free borrowing and lending is an unrealistic assumption. Fischer Black (1972) develops a version of the CAPM without risk-free borrowing or lending. He shows that the CAPM's key result—that the market portfolio is mean-variance-efficient—can be obtained by instead allowing unrestricted short sales of risky assets. In brief, back in Figure 1, if there is no risk-free asset, investors select portfolios from along the mean-variance-efficient frontier from a to b. Market clearing prices imply that when one weights the efficient portfolios chosen by investors by their (positive) shares of aggregate invested wealth, the resulting portfolio is the market portfolio. The market portfolio is thus a portfolio of the efficient portfolios chosen by investors. With unrestricted short selling of risky assets, portfolios made up of efficient portfolios are themselves efficient. Thus, the market portfolio is efficient, which means that the minimum variance condition for M given above holds, and it is the expected return-risk relation of the Black CAPM.

The relations between expected return and market beta of the Black and Sharpe-Lintner versions of the CAPM differ only in terms of what each says about $E(R_{ZM})$, the expected return on assets uncorrelated with the market. The Black version says only that $E(R_{ZM})$ must be less than the expected market return, so the

[3] Formally, if x_{iM} is the weight of asset i in the market portfolio, then the variance of the portfolio's return is

$$\sigma^2(R_M) = Cov(R_M, R_M) = Cov\left(\sum_{i=1}^{N} x_{iM}R_i,\ R_M\right) = \sum_{i=1}^{N} x_{iM}Cov(R_i, R_M).$$

premium for beta is positive. In contrast, in the Sharpe-Lintner version of the model, $E(R_{ZM})$ must be the risk-free interest rate, R_f, and the premium per unit of beta risk is $E(R_M) - R_f$.

The assumption that short selling is unrestricted is as unrealistic as unrestricted risk-free borrowing and lending. If there is no risk-free asset and short sales of risky assets are not allowed, mean-variance investors still choose efficient portfolios—points above *b* on the *abc* curve in Figure 1. But when there is no short selling of risky assets and no risk-free asset, the algebra of portfolio efficiency says that portfolios made up of efficient portfolios are not typically efficient. This means that the market portfolio, which is a portfolio of the efficient portfolios chosen by investors, is not typically efficient. And the CAPM relation between expected return and market beta is lost. This does not rule out predictions about expected return and betas with respect to other efficient portfolios—if theory can specify portfolios that must be efficient if the market is to clear. But so far this has proven impossible.

In short, the familiar CAPM equation relating expected asset returns to their market betas is just an application to the market portfolio of the relation between expected return and portfolio beta that holds in any mean-variance-efficient portfolio. The efficiency of the market portfolio is based on many unrealistic assumptions, including complete agreement and either unrestricted risk-free borrowing and lending or unrestricted short selling of risky assets. But all interesting models involve unrealistic simplifications, which is why they must be tested against data.

Early Empirical Tests

Tests of the CAPM are based on three implications of the relation between expected return and market beta implied by the model. First, expected returns on all assets are linearly related to their betas, and no other variable has marginal explanatory power. Second, the beta premium is positive, meaning that the expected return on the market portfolio exceeds the expected return on assets whose returns are uncorrelated with the market return. Third, in the Sharpe-Lintner version of the model, assets uncorrelated with the market have expected returns equal to the risk-free interest rate, and the beta premium is the expected market return minus the risk-free rate. Most tests of these predictions use either cross-section or time-series regressions. Both approaches date to early tests of the model.

Tests on Risk Premiums

The early cross-section regression tests focus on the Sharpe-Lintner model's predictions about the intercept and slope in the relation between expected return and market beta. The approach is to regress a cross-section of average asset returns on estimates of asset betas. The model predicts that the intercept in these regressions is the risk-free interest rate, R_f, and the coefficient on beta is the expected return on the market in excess of the risk-free rate, $E(R_M) - R_f$.

Two problems in these tests quickly became apparent. First, estimates of beta

for individual assets are imprecise, creating a measurement error problem when they are used to explain average returns. Second, the regression residuals have common sources of variation, such as industry effects in average returns. Positive correlation in the residuals produces downward bias in the usual ordinary least squares estimates of the standard errors of the cross-section regression slopes.

To improve the precision of estimated betas, researchers such as Blume (1970), Friend and Blume (1970) and Black, Jensen and Scholes (1972) work with portfolios, rather than individual securities. Since expected returns and market betas combine in the same way in portfolios, if the CAPM explains security returns it also explains portfolio returns.[4] Estimates of beta for diversified portfolios are more precise than estimates for individual securities. Thus, using portfolios in cross-section regressions of average returns on betas reduces the critical errors in variables problem. Grouping, however, shrinks the range of betas and reduces statistical power. To mitigate this problem, researchers sort securities on beta when forming portfolios; the first portfolio contains securities with the lowest betas, and so on, up to the last portfolio with the highest beta assets. This sorting procedure is now standard in empirical tests.

Fama and MacBeth (1973) propose a method for addressing the inference problem caused by correlation of the residuals in cross-section regressions. Instead of estimating a single cross-section regression of average monthly returns on betas, they estimate month-by-month cross-section regressions of monthly returns on betas. The times-series means of the monthly slopes and intercepts, along with the standard errors of the means, are then used to test whether the average premium for beta is positive and whether the average return on assets uncorrelated with the market is equal to the average risk-free interest rate. In this approach, the standard errors of the average intercept and slope are determined by the month-to-month variation in the regression coefficients, which fully captures the effects of residual correlation on variation in the regression coefficients, but sidesteps the problem of actually estimating the correlations. The residual correlations are, in effect, captured via repeated sampling of the regression coefficients. This approach also becomes standard in the literature.

Jensen (1968) was the first to note that the Sharpe-Lintner version of the

[4] Formally, if x_{ip}, $i = 1, \ldots, N$, are the weights for assets in some portfolio p, the expected return and market beta for the portfolio are related to the expected returns and betas of assets as

$$E(R_p) = \sum_{i=1}^{N} x_{ip}E(R_i), \text{ and } \beta_{pM} = \sum_{i=1}^{N} x_{ip}\beta_{pM}.$$

Thus, the CAPM relation between expected return and beta,

$$E(R_i) = E(R_f) + [E(R_M) - E(R_f)]\beta_{iM},$$

holds when asset i is a portfolio, as well as when i is an individual security.

relation between expected return and market beta also implies a time-series regression test. The Sharpe-Lintner CAPM says that the expected value of an asset's excess return (the asset's return minus the risk-free interest rate, $R_{it} - R_{ft}$) is completely explained by its expected CAPM risk premium (its beta times the expected value of $R_{Mt} - R_{ft}$). This implies that "Jensen's alpha," the intercept term in the time-series regression,

$$\text{(Time-Series Regression)} \quad R_{it} - R_{ft} = \alpha_i + \beta_{iM}(R_{Mt} - R_{ft}) + \varepsilon_{it},$$

is zero for each asset.

The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too "flat." Recall that, in cross-section regressions, the Sharpe-Lintner model predicts that the intercept is the risk-free rate and the coefficient on beta is the expected market return in excess of the risk-free rate, $E(R_M) - R_f$. The regressions consistently find that the intercept is greater than the average risk-free rate (typically proxied as the return on a one-month Treasury bill), and the coefficient on beta is less than the average excess market return (proxied as the average return on a portfolio of U.S. common stocks minus the Treasury bill rate). This is true in the early tests, such as Douglas (1968), Black, Jensen and Scholes (1972), Miller and Scholes (1972), Blume and Friend (1973) and Fama and MacBeth (1973), as well as in more recent cross-section regression tests, like Fama and French (1992).

The evidence that the relation between beta and average return is too flat is confirmed in time-series tests, such as Friend and Blume (1970), Black, Jensen and Scholes (1972) and Stambaugh (1982). The intercepts in time-series regressions of excess asset returns on the excess market return are positive for assets with low betas and negative for assets with high betas.

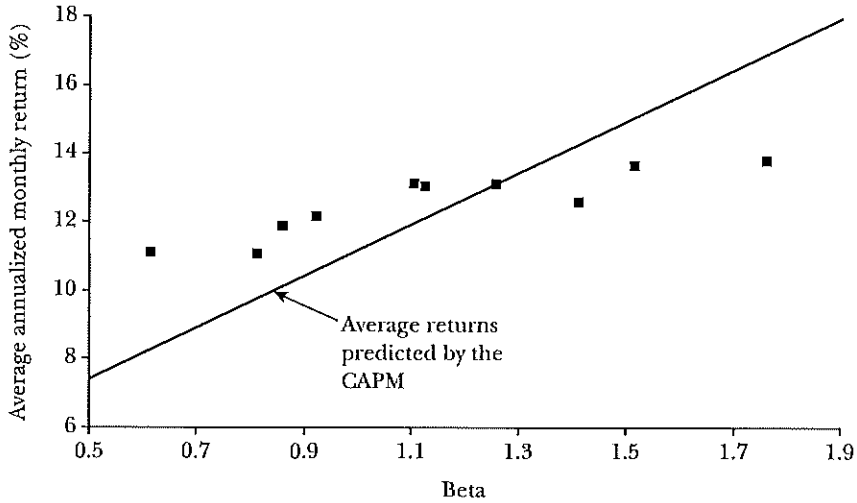
Figure 2 provides an updated example of the evidence. In December of each year, we estimate a preranking beta for every NYSE (1928–2003), AMEX (1963–2003) and NASDAQ (1972–2003) stock in the CRSP (Center for Research in Security Prices of the University of Chicago) database, using two to five years (as available) of prior monthly returns.[5] We then form ten value-weight portfolios based on these preranking betas and compute their returns for the next twelve months. We repeat this process for each year from 1928 to 2003. The result is 912 monthly returns on ten beta-sorted portfolios. Figure 2 plots each portfolio's average return against its postranking beta, estimated by regressing its monthly returns for 1928–2003 on the return on the CRSP value-weight portfolio of U.S. common stocks.

The Sharpe-Lintner CAPM predicts that the portfolios plot along a straight

[5] To be included in the sample for year t, a security must have market equity data (price times shares outstanding) for December of $t - 1$, and CRSP must classify it as ordinary common equity. Thus, we exclude securities such as American Depository Receipts (ADRs) and Real Estate Investment Trusts (REITs).

Figure 2

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



line, with an intercept equal to the risk-free rate, R_f, and a slope equal to the expected excess return on the market, $E(R_M) - R_f$. We use the average one-month Treasury bill rate and the average excess CRSP market return for 1928–2003 to estimate the predicted line in Figure 2. Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Lintner CAPM predicts. The returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return is 11.1 percent. The predicted return on the portfolio with the highest beta is 16.8 percent per year; the actual is 13.7 percent.

Although the observed premium per unit of beta is lower than the Sharpe-Lintner model predicts, the relation between average return and beta in Figure 2 is roughly linear. This is consistent with the Black version of the CAPM, which predicts only that the beta premium is positive. Even this less restrictive model, however, eventually succumbs to the data.

Testing Whether Market Betas Explain Expected Returns

The Sharpe-Lintner and Black versions of the CAPM share the prediction that the market portfolio is mean-variance-efficient. This implies that differences in expected return across securities and portfolios are entirely explained by differences in market beta; other variables should add nothing to the explanation of expected return. This prediction plays a prominent role in tests of the CAPM. In the early work, the weapon of choice is cross-section regressions.

In the framework of Fama and MacBeth (1973), one simply adds predetermined explanatory variables to the month-by-month cross-section regressions of

returns on beta. If all differences in expected return are explained by beta, the average slopes on the additional variables should not be reliably different from zero. Clearly, the trick in the cross-section regression approach is to choose specific additional variables likely to expose any problems of the CAPM prediction that, because the market portfolio is efficient, market betas suffice to explain expected asset returns.

For example, in Fama and MacBeth (1973) the additional variables are squared market betas (to test the prediction that the relation between expected return and beta is linear) and residual variances from regressions of returns on the market return (to test the prediction that market beta is the only measure of risk needed to explain expected returns). These variables do not add to the explanation of average returns provided by beta. Thus, the results of Fama and MacBeth (1973) are consistent with the hypothesis that their market proxy—an equal-weight portfolio of NYSE stocks—is on the minimum variance frontier.

The hypothesis that market betas completely explain expected returns can also be tested using time-series regressions. In the time-series regression described above (the excess return on asset i regressed on the excess market return), the intercept is the difference between the asset's average excess return and the excess return predicted by the Sharpe-Lintner model, that is, beta times the average excess market return. If the model holds, there is no way to group assets into portfolios whose intercepts are reliably different from zero. For example, the intercepts for a portfolio of stocks with high ratios of earnings to price and a portfolio of stocks with low earning-price ratios should both be zero. Thus, to test the hypothesis that market betas suffice to explain expected returns, one estimates the time-series regression for a set of assets (or portfolios) and then jointly tests the vector of regression intercepts against zero. The trick in this approach is to choose the left-hand-side assets (or portfolios) in a way likely to expose any shortcoming of the CAPM prediction that market betas suffice to explain expected asset returns.

In early applications, researchers use a variety of tests to determine whether the intercepts in a set of time-series regressions are all zero. The tests have the same asymptotic properties, hut there is controversy about which has the best small sample properties. Gibbons, Ross and Shanken (1989) settle the debate by providing an F-test on the intercepts that has exact small-sample properties. They also show that the test has a simple economic interpretation. In effect, the test constructs a candidate for the tangency portfolio T in Figure 1 by optimally combining the market proxy and the left-hand-side assets of the time-series regressions. The estimator then tests whether the efficient set provided by the combination of this tangency portfolio and the risk-free asset is reliably superior to the one obtained by combining the risk-free asset with the market proxy alone. In other words, the Gibbons, Ross and Shanken statistic tests whether the market proxy is the tangency portfolio in the set of portfolios that can be constructed by combining the market portfolio with the specific assets used as dependent variables in the time-series regressions.

Enlightened by this insight of Gibbons, Ross and Shanken (1989), one can see

a similar interpretation of the cross-section regression test of whether market betas suffice to explain expected returns. In this case, the test is whether the additional explanatory variables in a cross-section regression identify patterns in the returns on the left-hand-side assets that are not explained by the assets' market betas. This amounts to testing whether the market proxy is on the minimum variance frontier that can be constructed using the market proxy and the left-hand-side assets included in the tests.

An important lesson from this discussion is that time-series and cross-section regressions do not, strictly speaking, test the CAPM. What is literally tested is whether a specific proxy for the market portfolio (typically a portfolio of U.S. common stocks) is efficient in the set of portfolios that can be constructed from it and the left-hand-side assets used in the test. One might conclude from this that the CAPM has never been tested, and prospects for testing it are not good because 1) the set of left-hand-side assets does not include all marketable assets, and 2) data for the true market portfolio of all assets are likely beyond reach (Roll, 1977; more on this later). But this criticism can be leveled at tests of any economic model when the tests are less than exhaustive or when they use proxies for the variables called for by the model.

The bottom line from the early cross-section regression tests of tbe CAPM, such as Fama and MacBeth (1973), and the early time-series regression tests, like Gibbons (1982) and Stambaugh (1982), is that standard market proxies seem to be on the minimum variance frontier. That is, the central predictions of the Black version of the CAPM, that market betas suffice to explain expected returns and that the risk premium for beta is positive, seem to hold. But the more specific prediction of the Sharpe-Lintner CAPM that the premium per unit of beta is the expected market return minus the risk-free interest rate is consistently rejected.

The success of the Black version of the CAPM in early tests produced a consensus that the model is a good description of expected returns. These early results, coupled with the model's simplicity and intuitive appeal, pushed the CAPM to the forefront of finance.

Recent Tests

Starting in the late 1970s, empirical work appears that challenges even the Black version of the CAPM. Specifically, evidence mounts that much of the variation in expected return is unrelated to market beta.

The first blow is Basu's (1977) evidence that when common stocks are sorted on earnings-price ratios, future returns on high E/P stocks are higher than predicted by the CAPM. Banz (1981) documents a size effect: when stocks are sorted on market capitalization (price times shares outstanding), average returns on small stocks are higher than predicted by the CAPM. Bhandari (1988) finds that high debt-equity ratios (book value of debt over the market value of equity, a measure of leverage) are associated with returns that are too high relative to their market betas.

Finally, Statman (1980) and Rosenberg, Reid and Lanstein (1985) document that stocks with high book-to-market equity ratios (B/M, the ratio of the book value of a common stock to its market value) have high average returns that are not captured by their betas.

There is a theme in the contradictions of the CAPM summarized above. Ratios involving stock prices have information about expected returns missed by market betas. On reflection, this is not surprising. A stock's price depends not only on the expected cash flows it will provide, but also on the expected returns that discount expected cash flows back to the present. Thus, in principle, the cross-section of prices has information about the cross-section of expected returns. (A high expected return implies a high discount rate and a low price.) The cross-section of stock prices is, however, arbitrarily affected by differences in scale (or units). But with a judicious choice of scaling variable X, the ratio X/P can reveal differences in the cross-section of expected stock returns. Such ratios are thus prime candidates to expose shortcomings of asset pricing models—in the case of the CAPM, shortcomings of the prediction that market betas suffice to explain expected returns (Ball, 1978). The contradictions of the CAPM summarized above suggest that earnings-price, debt-equity and book-to-market ratios indeed play this role.

Fama and French (1992) update and synthesize the evidence on the empirical failures of the CAPM. Using the cross-section regression approach, they confirm that size, earnings-price, debt-equity and book-to-market ratios add to the explanation of expected stock returns provided by market beta. Fama and French (1996) reach the same conclusion using the time-series regression approach applied to portfolios of stocks sorted on price ratios. They also find that different price ratios have much the same information about expected returns. This is not surprising given that price is the common driving force in the price ratios, and the numerators are just scaling variables used to extract the information in price about expected returns.

Fama and French (1992) also confirm the evidence (Reinganum, 1981; Stambaugh, 1982; Lakonishok and Shapiro, 1986) that the relation between average return and beta for common stocks is even flatter after the sample periods used in the early empirical work on the CAPM. The estimate of the beta premium is, however, clouded by statistical uncertainty (a large standard error). Kothari, Shanken and Sloan (1995) try to resuscitate the Sharpe-Lintner CAPM by arguing that the weak relation between average return and beta is just a chance result. But the strong evidence that other variables capture variation in expected return missed by beta makes this argument irrelevant. If betas do not suffice to explain expected returns, the market portfolio is not efficient, and the CAPM is dead in its tracks. Evidence on the size of the market premium can neither save the model nor further doom it.

The synthesis of the evidence on the empirical problems of the CAPM provided by Fama and French (1992) serves as a catalyst, marking the point when it is generally acknowledged that the CAPM has potentially fatal problems. Research then turns to explanations.

One possibility is that the CAPM's problems are spurious, the result of data dredging—publication-hungry researchers scouring the data and unearthing contradictions that occur in specific samples as a result of chance. A standard response to this concern is to test for similar findings in other samples. Chan, Hamao and Lakonishok (1991) find a strong relation between book-to-market equity (B/M) and average return for Japanese stocks. Capaul, Rowley and Sharpe (1993) observe a similar B/M effect in four European stock markets and in Japan. Fama and French (1998) find that the price ratios that produce problems for the CAPM in U.S. data show up in the same way in the stock returns of twelve non-U.S. major markets, and they are present in emerging market returns. This evidence suggests that the contradictions of the CAPM associated with price ratios are not sample specific.

Explanations: Irrational Pricing or Risk

Among those who conclude that the empirical failures of the CAPM are fatal, two stories emerge. On one side are the behavioralists. Their view is based on evidence that stocks with high ratios of book value to market price are typically firms that have fallen on bad times, while low B/M is associated with growth firms (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1995). The behavioralists argue that sorting firms on book-to-market ratios exposes investor overreaction to good and bad times. Investors overextrapolate past performance, resulting in stock prices that are too high for growth (low B/M) firms and too low for distressed (high B/M, so-called value) firms. When the overreaction is eventually corrected, the result is high returns for value stocks and low returns for growth stocks. Proponents of this view include DeBondt and Thaler (1987), Lakonishok, Shleifer and Vishny (1994) and Haugen (1995).

The second story for explaining the empirical contradictions of the CAPM is that they point to the need for a more complicated asset pricing model. The CAPM is based on many unrealistic assumptions. For example, the assumption that investors care only about the mean and variance of one-period portfolio returns is extreme. It is reasonable that investors also care about how their portfolio return covaries with labor income and future investment opportunities, so a portfolio's return variance misses important dimensions of risk. If so, market beta is not a complete description of an asset's risk, and we should not be surprised to find that differences in expected return are not completely explained by differences in beta. In this view, the search should turn to asset pricing models that do a better job explaining average returns.

Merton's (1973) intertemporal capital asset pricing model (ICAPM) is a natural extension of the CAPM. The ICAPM begins with a different assumption about investor objectives. In the CAPM, investors care only about the wealth their portfolio produces at the end of the current period. In the ICAPM, investors are concerned not only with their end-of-period payoff, but also with the opportunities

they will have to consume or invest the payoff. Thus, when choosing a portfolio at time $t - 1$, ICAPM investors consider how their wealth at t might vary with future *state variables*, including labor income, the prices of consumption goods and the nature of portfolio opportunities at t, and expectations about the labor income, consumption and investment opportunities to be available after t.

Like CAPM investors, ICAPM investors prefer high expected return and low return variance. But ICAPM investors are also concerned with the covariances of portfolio returns with state variables. As a result, optimal portfolios are "multifactor efficient," which means they have the largest possible expected returns, given their return variances and the covariances of their returns with the relevant state variables.

Fama (1996) shows that the ICAPM generalizes the logic of the CAPM. That is, if there is risk-free borrowing and lending or if short sales of risky assets are allowed, market clearing prices imply that the market portfolio is multifactor efficient. Moreover, multifactor efficiency implies a relation between expected return and beta risks, but it requires additional betas, along with a market beta, to explain expected returns.

An ideal implementation of the ICAPM would specify the state variables that affect expected returns. Fama and French (1993) take a more indirect approach, perhaps more in the spirit of Ross's (1976) arbitrage pricing theory. They argue that though size and book-to-market equity are not themselves state variables, the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns that are not captured by the market return and are priced separately from market betas. In support of this claim, they show that the returns on the stocks of small firms covary more with one another than with returns on the stocks of large firms, and returns on high book-to-market (value) stocks covary more with one another than with returns on low book-to-market (growth) stocks. Fama and French (1995) show that there are similar size and book-to-market patterns in the covariation of fundamentals like earnings and sales.

Based on this evidence, Fama and French (1993, 1996) propose a three-factor model for expected returns,

$$\text{(Three-Factor Model)} \quad E(R_{it}) - R_{ft} = \beta_{iM}[E(R_{Mt}) - R_{ft}] + \beta_{is}E(SMB_t) + \beta_{ih}E(HML_t).$$

In this equation, SMB_t (small minus big) is the difference between the returns on diversified portfolios of small and big stocks, HML_t (high minus low) is the difference between the returns on diversified portfolios of high and low B/M stocks, and the betas are slopes in the multiple regression of $R_{it} - R_{ft}$ on $R_{Mt} - R_{ft}$, SMB_t and HML_t.

For perspective, the average value of the market premium $R_{Mt} - R_{ft}$ for 1927–2003 is 8.3 percent per year, which is 3.5 standard errors from zero. The

average values of SMB_t, and HML_t are 3.6 percent and 5.0 percent per year, and they are 2.1 and 3.1 standard errors from zero. All three premiums are volatile, with annual standard deviations of 21.0 percent $(R_{Mt} - R_{ft})$, 14.6 percent (SMB_t) and 14.2 percent (HML_t) per year. Although the average values of the premiums are large, high volatility implies substantial uncertainty about the true expected premiums.

One implication of the expected return equation of the three-factor model is that the intercept α_i in the time-series regression,

$$R_{it} - R_{ft} = \alpha_i + \beta_{iM}(R_{Mt} - R_{ft}) + \beta_{is}SMB_t + \beta_{ih}HML_t + \varepsilon_{it},$$

is zero for all assets i. Using this criterion, Fama and French (1993, 1996) find that the model captures much of the variation in average return for portfolios formed on size, book-to-market equity and other price ratios that cause problems for the CAPM. Fama and French (1998) show that an international version of the model performs better than an international CAPM in describing average returns on portfolios formed on scaled price variables for stocks in 13 major markets.

The three-factor model is now widely used in empirical research that requires a model of expected returns. Estimates of α_i from the time-series regression above are used to calibrate how rapidly stock prices respond to new information (for example, Loughran and Ritter, 1995; Mitchell and Stafford, 2000). They are also used to measure the special information of portfolio managers, for example, in Carhart's (1997) study of mutual fund performance. Among practitioners like Ibbotson Associates, the model is offered as an alternative to the CAPM for estimating the cost of equity capital.

From a theoretical perspective, the main shortcoming of the three-factor model is its empirical motivation. The small-minus-big (SMB) and high-minus-low (HML) explanatory returns are not motivated by predictions about state variables of concern to investors. Instead they are brute force constructs meant to capture the patterns uncovered by previous work on how average stock returns vary with size and the book-to-market equity ratio.

But this concern is not fatal. The ICAPM does not require that the additional portfolios used along with the market portfolio to explain expected returns "mimic" the relevant state variables. In both the ICAPM and the arbitrage pricing theory, it suffices that the additional portfolios are well diversified (in the terminology of Fama, 1996, they are multifactor minimum variance) and that they are sufficiently different from the market portfolio to capture covariation in returns and variation in expected returns missed by the market portfolio. Thus, adding diversified portfolios that capture covariation in returns and variation in average returns left unexplained by the market is in the spirit of both the ICAPM and the Ross's arbitrage pricing theory.

The behavioralists are not impressed by the evidence for a risk-based explanation of the failures of the CAPM. They typically concede that the three-factor model captures covariation in returns missed by the market return and that it picks

up much of the size and value effects in average returns left unexplained by the CAPM. But their view is that the average return premium associated with the model's book-to-market factor—which does the heavy lifting in the improvements to the CAPM—is itself the result of investor overreaction that happens to be correlated across firms in a way that just looks like a risk story. In short, in the behavioral view, the market tries to set CAPM prices, and violations of the CAPM are due to mispricing.

The conflict between the behavioral irrational pricing story and the rational risk story for the empirical failures of the CAPM leaves us at a timeworn impasse. Fama (1970) emphasizes that the hypothesis that prices properly reflect available information must be tested in the context of a model of expected returns, like the CAPM. Intuitively, to test whether prices are rational, one must take a stand on what the market is trying to do in setting prices—that is, what is risk and what is the relation between expected return and risk? When tests reject the CAPM, one cannot say whether the problem is its assumption that prices are rational (the behavioral view) or violations of other assumptions that are also necessary to produce the CAPM (our position).

Fortunately, for some applications, the way one uses the three-factor model does not depend on one's view about whether its average return premiums are the rational result of underlying state variable risks, the result of irrational investor behavior or sample specific results of chance. For example, when measuring the response of stock prices to new information or when evaluating the performance of managed portfolios, one wants to account for known patterns in returns and average returns for the period examined, whatever their source. Similarly, when estimating the cost of equity capital, one might be unconcerned with whether expected return premiums are rational or irrational since they are in either case part of the opportunity cost of equity capital (Stein, 1996). But the cost of capital is forward looking, so if the premiums are sample specific they are irrelevant.

The three-factor model is hardly a panacea. Its most serious problem is the momentum effect of Jegadeesh and Titman (1993). Stocks that do well relative to the market over the last three to twelve months tend to continue to do well for the next few months, and stocks that do poorly continue to do poorly. This momentum effect is distinct from the value effect captured by book-to-market equity and other price ratios. Moreover, the momentum effect is left unexplained by the three-factor model, as well as by the CAPM. Following Carhart (1997), one response is to add a momentum factor (the difference between the returns on diversified portfolios of short-term winners and losers) to the three-factor model. This step is again legitimate in applications where the goal is to abstract from known patterns in average returns to uncover information-specific or manager-specific effects. But since the momentum effect is short-lived, it is largely irrelevant for estimates of the cost of equity capital.

Another strand of research points to problems in both the three-factor model and the CAPM. Frankel and Lee (1998), Dechow, Hutton and Sloan (1999), Piotroski (2000) and others show that in portfolios formed on price ratios like

book-to-market equity, stocks with higher expected cash flows have higher average returns that are not captured by the three-factor model or the CAPM. The authors interpret their results as evidence that stock prices are irrational, in the sense that they do not reflect available information about expected profitability.

In truth, however, one can't tell whether the problem is bad pricing or a bad asset pricing model. A stock's price can always be expressed as the present value of expected future cash flows discounted at the expected return on the stock (Campbell and Shiller, 1989; Vuolteenaho, 2002). It follows that if two stocks have the same price, the one with higher expected cash flows must have a higher expected return. This holds true whether pricing is rational or irrational. Thus, when one observes a positive relation between expected cash flows and expected returns that is left unexplained by the CAPM or the three-factor model, one can't tell whether it is the result of irrational pricing or a misspecified asset pricing model.

The Market Proxy Problem

Roll (1977) argues that the CAPM has never been tested and probably never will be. The problem is that the market portfolio at the heart of the model is theoretically and empirically elusive. It is not theoretically clear which assets (for example, human capital) can legitimately be excluded from the market portfolio, and data availability substantially limits the assets that are included. As a result, tests of the CAPM are forced to use proxies for the market portfolio, in effect testing whether the proxies are on the minimum variance frontier. Roll argues that because the tests use proxies, not the true market portfolio, we learn nothing about the CAPM.

We are more pragmatic. The relation between expected return and market beta of the CAPM is just the minimum variance condition that holds in any efficient portfolio, applied to the market portfolio. Thus, if we can find a market proxy that is on the minimum variance frontier, it can be used to describe differences in expected returns, and we would be happy to use it for this purpose. The strong rejections of the CAPM described above, however, say that researchers have not uncovered a reasonable market proxy that is close to the minimum variance frontier. If researchers are constrained to reasonable proxies, we doubt they ever will.

Our pessimism is fueled by several empirical results. Stambaugh (1982) tests the CAPM using a range of market portfolios that include, in addition to U.S. common stocks, corporate and government bonds, preferred stocks, real estate and other consumer durables. He finds that tests of the CAPM are not sensitive to expanding the market proxy beyond common stocks, basically because the volatility of expanded market returns is dominated by the volatility of stock returns.

One need not be convinced by Stambaugh's (1982) results since his market proxies are limited to U.S. assets. If international capital markets are open and asset prices conform to an international version of the CAPM, the market portfolio

should include international assets. Fama and French (1998) find, however, that betas for a global stock market portfolio cannot explain the high average returns observed around the world on stocks with high book-to-market or high earnings-price ratios.

A major problem for the CAPM is that portfolios formed by sorting stocks on price ratios produce a wide range of average returns, but the average returns are not positively related to market betas (Lakonishok, Shleifer and Vishny, 1994; Fama and French, 1996, 1998). The problem is illustrated in Figure 3, which shows average returns and betas (calculated with respect to the CRSP value-weight portfolio of NYSE, AMEX and NASDAQ stocks) for July 1963 to December 2003 for ten portfolios of U.S. stocks formed annually on sorted values of the book-to-market equity ratio (B/M).[6]

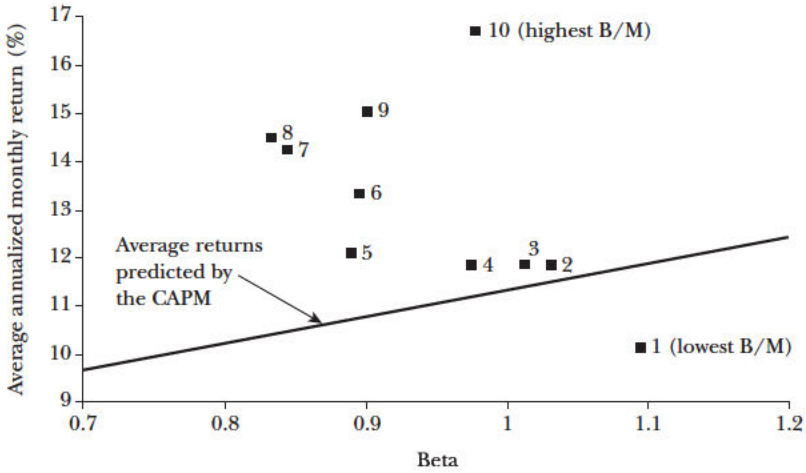
Average returns on the B/M portfolios increase almost monotonically, from 10.1 percent per year for the lowest B/M group (portfolio 1) to an impressive 16.7 percent for the highest (portfolio 10). But the positive relation between beta and average return predicted by the CAPM is notably absent. For example, the portfolio with the lowest book-to-market ratio has the highest beta but the lowest average return. The estimated beta for the portfolio with the highest book-to-market ratio and the highest average return is only 0.98. With an average annualized value of the riskfree interest rate, R_f, of 5.8 percent and an average annualized market premium, $R_M - R_f$, of 11.3 percent, the Sharpe-Lintner CAPM predicts an average return of 11.8 percent for the lowest B/M portfolio and 11.2 percent for the highest, far from the observed values, 10.1 and 16.7 percent. For the Sharpe-Lintner model to "work" on these portfolios, their market betas must change dramatically, from 1.09 to 0.78 for the lowest B/M portfolio and from 0.98 to 1.98 for the highest. We judge it unlikely that alternative proxies for the market portfolio will produce betas and a market premium that can explain the average returns on these portfolios.

It is always possible that researchers will redeem the CAPM by finding a reasonable proxy for the market portfolio that is on the minimum variance frontier. We emphasize, however, that this possibility cannot be used to justify the way the CAPM is currently applied. The problem is that applications typically use the same

[6] Stock return data are from CRSP, and book equity data are from Compustat and the Moody's Industrials, Transportation, Utilities and Financials manuals. Stocks are allocated to ten portfolios at the end of June of each year t (1963 to 2003) using the ratio of book equity for the fiscal year ending in calendar year $t - 1$, divided by market equity at the end of December of $t - 1$. Book equity is the book value of stockholders' equity, plus balance sheet deferred taxes and investment tax credit (if available), minus the book value of preferred stock. Depending on availability, we use the redemption, liquidation or par value (in that order) to estimate the book value of preferred stock. Stockholders' equity is the value reported by Moody's or Compustat, if it is available. If not, we measure stockholders' equity as the book value of common equity plus the par value of preferred stock or the book value of assets minus total liabilities (in that order). The portfolios for year t include NYSE (1963–2003), AMEX (1963–2003) and NASDAQ (1972–2003) stocks with positive book equity in $t - 1$ and market equity (from CRSP) for December of $t - 1$ and June of t. The portfolios exclude securities CRSP does not classify as ordinary common equity. The breakpoints for year t use only securities that are on the NYSE in June of year t.

Figure 3

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on B/M, 1963–2003



market proxies, like the value-weight portfolio of U.S. stocks, that lead to rejections of the model in empirical tests. The contradictions of the CAPM observed when such proxies are used in tests of the model show up as bad estimates of expected returns in applications; for example, estimates of the cost of equity capital that are too low (relative to historical average returns) for small stocks and for stocks with high book-to-market equity ratios. In short, if a market proxy does not work in tests of the CAPM, it does not work in applications.

Conclusions

The version of the CAPM developed by Sharpe (1964) and Lintner (1965) has never been an empirical success. In the early empirical work, the Black (1972) version of the model, which can accommodate a flatter tradeoff of average return for market beta, has some success. But in the late 1970s, research begins to uncover variables like size, various price ratios and momentum that add to the explanation of average returns provided by beta. The problems are serious enough to invalidate most applications of the CAPM.

For example, finance textbooks often recommend using the Sharpe-Lintner CAPM risk-return relation to estimate the cost of equity capital. The prescription is to estimate a stock's market beta and combine it with the risk-free interest rate and the average market risk premium to produce an estimate of the cost of equity. The typical market portfolio in these exercises includes just U.S. common stocks. But empirical work, old and new, tells us that the relation between beta and average return is flatter than predicted by the Sharpe-Lintner version of the CAPM. As a

result, CAPM estimates of the cost of equity for high beta stocks are too high (relative to historical average returns) and estimates for low beta stocks are too low (Friend and Blume, 1970). Similarly, if the high average returns on value stocks (with high book-to-market ratios) imply high expected returns, CAPM cost of equity estimates for such stocks are too low.[7]

The CAPM is also often used to measure the performance of mutual funds and other managed portfolios. The approach, dating to Jensen (1968), is to estimate the CAPM time-series regression for a portfolio and use the intercept (Jensen's alpha) to measure abnormal performance. The problem is that, because of the empirical failings of the CAPM, even passively managed stock portfolios produce abnormal returns if their investment strategies involve tilts toward CAPM problems (Elton, Gruber, Das and Hlavka, 1993). For example, funds that concentrate on low beta stocks, small stocks or value stocks will tend to produce positive abnormal returns relative to the predictions of the Sharpe-Lintner CAPM, even when the fund managers have no special talent for picking winners.

The CAPM, like Markowitz's (1952, 1959) portfolio model on which it is built, is nevertheless a theoretical tour de force. We continue to teach the CAPM as an introduction to the fundamental concepts of portfolio theory and asset pricing, to be built on by more complicated models like Merton's (1973) ICAPM. But we also warn students that despite its seductive simplicity, the CAPM's empirical problems probably invalidate its use in applications.

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[7] The problems are compounded by the large standard errors of estimates of the market premium and of betas for individual stocks, which probably suffice to make CAPM estimates of the cost of equity rather meaningless, even if the CAPM holds (Fama and French, 1997; Pastor and Stambaugh, 1999). For example, using the U.S. Treasury bill rate as the risk-free interest rate and the CRSP value-weight portfolio of publicly traded U.S. common stocks, the average value of the equity premium $R_{Mt} - R_{ft}$ for 1927–2003 is 8.3 percent per year, with a standard error of 2.4 percent. The two standard error range thus runs from 3.5 percent to 13.1 percent, which is sufficient to make most projects appear either profitable or unprofitable. This problem is, however, hardly special to the CAPM. For example, expected returns in all versions of Merton's (1973) ICAPM include a market beta and the expected market premium. Also, as noted earlier the expected values of the size and book-to-market premiums in the Fama-French three-factor model are also estimated with substantial error.

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The real-time price elasticity of electricity

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Abstract

The real-time price elasticity of electricity contains important information on the demand response of consumers to the volatility of peak prices. Despite the importance, empirical estimates of the real-time elasticity are hardly available. This paper provides a quantification of the real-time relationship between total peak demand and spot market prices. We find a low value for the real-time price elasticity, which may partly be explained from the fact that not all users observe the spot market price. If we correct for this phenomenon, we find the elasticity to be fairly low for consumers currently active in the spot market. If this conclusion applies to all users, this would imply a limited scope for government intervention in supply security issues.
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1. Introduction

Following several major black-outs around the Western world, security of electricity supply has gained an enormous amount of attention, both from academics and policy makers. For decades, the provision of electricity was characterized by centralized systems with vast overcapacity. Following the liberalization of electricity markets, producers rationalize their capacity, leading to a decrease in overcapacity. Although the reduction in overcapacity may be desirable from a cost efficiency point of view, it also increases the risk of excess demand, ultimately resulting in black-outs.

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Policy makers wishing to counteract black-outs often aim their focus on re-establishing the traditional situation of overcapacity, which is why the focus in many of the discussions is on measures on the supply side. Recent focus in the literature is on capacity markets (e.g. Hobs et al., 2001) and capacity payments (e.g. Ford, 1999; Oren, 2000).

Rather than increasing capacity, excess demand may also be counteracted by increasing the price responsiveness of demand. Most end-users do not observe real-time prices and hence cannot react to them. Policies aimed at providing price information as well as incentives to react may be much more cost effective than retaining large amounts of spare capacity. Mixed systems, combining spare capacity and demand response (e.g. Doorman, 2003), are currently being considered. Insight into the order of magnitude of demand reactions is useful to assess the effects of policy options aimed at demand response.

This paper focuses on the demand response in the electricity market, trying to empirically estimate the real-time elasticity of electricity. We define the real-time elasticity as the price elasticity of demand on an hour-to-hour basis.[1] The current literature regarding price elasticities focuses on quarterly (e.g. Beenstock et al., 1999), or annual data (e.g. Urga and Walters, 2003; Al Faris, 2002), or on elasticities of time of use pricing (e.g. Aigner et al., 1994; Filippini, 1995). Literature on real-time elasticities is very scarce however, Patrick and Wolack (1997) being the notable exception.

The remainder of this paper is organized as follows. The following section looks more closely into the role of demand elasticity in demand response. Section 3 provides a brief overview of recent empirical results regarding price elasticities of electricity, followed by a discussion of our framework. Data and empirical results are reported in Sections 5 and 6 concludes, presenting the implications and conclusions.

2. Demand response and price elasticity

The non-storability of electricity implies that electricity supply is capped in the short run. The combination of this feature with time-varying demand is often held responsible for the vulnerability of supply security in electricity markets. These characteristics of electricity markets do not constitute a novelty, the only difference is that the cap on supply was on a much higher level in the recent past, so that it was hardly ever binding.

This combination of characteristics is not unique to electricity markets. All services are non-storable and many of them have fluctuating demand over time. Let us turn to the very similar example of road transport.

Virtually every urban area in the world suffers from highway congestion during rush hours, a problem very similar to that of the electricity market, as supply is fixed in the short run by road capacity and demand fluctuates strongly over time. Congestion, both on highways and on electricity networks, may be viewed as an externality. Adding one unit of demand above a certain threshold level has a negative impact on the quality of the good for all users. The marginal customer is not charged for all the costs he incurs. In the case of electricity, an increase in demand beyond available capacity levels increases the probability of a black-out, thus imposing (expected) outage costs on all users.

Comparing policy proposals for security of supply with those for solving traffic congestion reveals that the implicit value of black-outs is much higher than that of traffic jams.

[1] Note that electricity is often traded at day ahead markets, so that the trade reaction is real-time, but the actual effect on load is not. This implies that these reactions cannot take into account unexpected events, such as power plant outages.

Table 1
Long and short run elasticity estimates

Source	Type of model	Type of data	Long term	Short term
Al Faris (2002)	Error correction model	Annual time series, 1970 1997	−0.82/−3.39	−0.04/−0.18
Beenstock et al. (1999)	Error correction model	Quarterly time series, 1973 1994	Households: −0.579 Industry: −0.311	Households: −0.124 Industry: −0.123
Bjørner and Jensen (2002)	Loglinear, fixed effects	Panel, 1983 1996		−0.479
Boonekamp (2007)	Bottom-up	Annual time series, 1990 2000	Households: −0.09/−0.13	
Brännlund et al. (in press)	AID-model	Quarterly time series, 1980 1997		Households: −0.24
Caloghirou et al. (1997)	Translog	Panel, 1980 1991	Industry: −0.77	Industry: −0.51
Elkhafif (1992)	Loglinear	Annual time series, 1963 1990	−0.697	−0.147
Filippini and Pachuari (2002)	Loglinear	Monthly household panel, 1993 1994		Households: −0.16/−0.39
Hesse and Tarkka (1986)	Translog	Panel, 1973 1980		−0.14/−0.49
Holtedahl and Loutz (2004)	Long term: loglinear Short term: error correction model	Annual time series, 1955 1996	Households: −0.16	Households: −0.15
Ilmakunnas and Törmä (1989)	Generalized Leontief	Annual time series, 1960 1981		−0.73
Jones (1995)	Loglinear Translog	Annual time series, 1960 1992	−0.207 −0.201	−0.05 −0.276
Roy et al. (in press)	Translog	Pooled country panel, 1980 1993	Industrial: −0.8/−1.76	
Taheri (1994), Urga and Walters (2003)	Translog Loglinear Translog	Panel, 1974 1981 Annual time series, 1960 1992[b]	−0.845 −0.2609 −0.1042	−0.888[a] −0.071 −0.101
Woodland (1993)	Translog	Panel, 1977 1985		−1.113
Zachariadis and Pashourtidou (2007)	Error correction model	Annual time series, 1960 2004	−0.3/−0.4	[a]

[a] Not significantly different from zero.
[b] Same data as Jones (1995).

Are these implicit valuations inaccurate, or may these differences be explained by a different starting point in looking for solutions? With traffic congestion, pricing policies become more and more popular, which raises the question whether pricing is also an option for securing electricity supply.

If all externalities are internal to the market at stake (i.e. users impose costs on each other, as is often the case with congestion), either tradable permits or peak load pricing will bring about the optimal outcome.[2] Many electricity markets already have a combination of peak load pricing and tradable permits in place, through spot markets and sometimes also through unbalance pricing mechanisms. One of the problems here is that many consumers do not observe real-time prices and hence cannot react to them.

[2] See e.g. Boiteux (1960) for formal proof and further discussion.

Increasing demand reactions to price fluctuations may be a more efficient way to increase supply security than simply retaining large amounts of unused spare generation capacity. In order to assess the costs and benefits of possible options aimed at increasing demand responsiveness, one first needs to have insight into the current level of demand response. The level of demand response is also important in assessing the efficient level of capacity related security of supply measures.[3]

3. Price elasticities of electricity

When looking at empirical estimates of elasticities of electricity, one can distinguish between long term elasticities, short term elasticities (i.e. 1 year or less) and elasticities from time-of-use studies. Long term elasticities often follow from the same study, simply by adding up lagged price effects of short term elasticities. Several authors have recently published empirical estimations of electricity elasticities. Table 1 summarizes the results of recent studies.[4]

Al Faris (2002) estimates separate error correction models for Saudi Arabia, UAE, Kuwait, Oman, Bahrain and Qatar, finding short term demand elasticities ranging from −0.04 to −0.18. Estimates by Elkhafif (1992), Holtedahl and Loutz (2004), Jones (1995, loglinear specification), Urga and Walters (2003) and Beenstock et al. (1999) lie within this range, although the latter also find much lower values using the Engle and Granger method (Engle et al., 1989). These results are however hard to compare to the other outcomes presented here. Several studies find somewhat higher (Brännlund et al. (in press), Filippini and Pachuari (2002), Hesse and Tarkka (1986)) or much higher own price elasticities for electricity.

The results in Table 1 suggest that panel data yield higher (absolute) results than aggregated time series. This may result from the causality problem in measuring demand reactions. If demand grows because of an exogenous reason, scarcity increases and prices rise, suggesting a positive relationship between the two. This positive relationship counteracts the negative relationship of price on demand and may dampen the price effect visible on an aggregated level. On a disaggregated level this problem does not arise, as demand growth of an individual consumer is unlikely to influence prices.

In the past decade, several publications on time-of-use (TOU) pricing of electricity have been published. These publications study the demand effect of price differentials between peak and off-peak prices for end-users and may also give some clue on price elasticities of electricity. Table 2 lists elasticities from recent studies on TOU-pricing.

Aigner et al. (1994) link price elasticities to the ratio of the peak price to the off-peak price for two- and three-price systems. For ease of comparison, we only show elasticities from the two-price system here. At higher peak prices, elasticities for peak and off-peak are closer to each other. Mountain and Lawson (1992) report fairly low values for time of use pricing elasticities, whereas the results found in Filippini (1995) are very high. The magnitude of the values found for own and cross price elasticities suggests that Fillipini's results may be influenced by misspecification. Ham et al. (1997) estimate elasticities for small commercial establishments, finding a range from −0.038 to −0.050 for off-peak own price elasticities and −0.069 to −0.091 for peak own price elasticities. They find that substitution between peak and off-peak does not differ significantly from zero for this group of users.

[3] See Lijesen and Vollaard (2004).
[4] For older studies, see the review in Taylor (1975).

Table 2
Elasticity estimates from recent studies on TOU-pricing

Source	Type of model	Own elasticity	Cross elasticity
Aigner et al. (1994)	Generalized Leontief	Off-peak: −0.013/−0.049 Peak: −0.054/−0.158	Not reported
Boisvert et al. (2004)	Generalized Leontief	Peak: −0.05/−0.0675	See main text
Filippini (1995)	Partial equilibrium model, loglinear demand	Off-peak: −2.30/−2.57 Peak: −1.25/−1.41	0.34/1.57
Ham et al. (1997)	Loglinear	Off-peak: −0.038/−0.050 Peak: −0.069/−0.091	Not significantly different from zero
Mountain and Lawson (1992)	Loglinear	Off-peak: −0.003/−0.036 Peak: −0.002/−0.138	0.003/0.037

Boisvert et al. (2004) estimate substitution elasticities for peak–off-peak price differentials of 0.2 to 0.27, and calculate that 75% of the change in electricity usage is due to shifting load. This implies that the own price elasticity of electricity is about one quarter of the substitution elasticity.

The only authors to address real-time elasticities explicitly are Patrick and Wolack (1997). They give a detailed empirical analysis of real-time demand response for 5 industrial sectors in the UK.[5] They find fairly low price elasticities, ranging from virtually zero to −0.05 for four of the five sectors. The water supply industry exhibits a wider range, with elasticities between zero and −0.27. For three out of five sectors, Patrick and Wolack find the absolute value of the elasticity to be relatively high at peak hours, late in the afternoon. As prices are higher during peak hours, this finding may support a more or less linear demand relationship.

Looking at hour-to-hour patterns of own and cross price elasticities, Patrick and Wolack (1997) conclude that "…most of the substitutability in electricity consumption within the day comes from substitution across adjacent load periods."[6] For continuously running production processes they find complementarity within production shifts. A demand reduction in a production shift decreases demand in that entire shift.

4. Framework

We determine the relationship between total demand and its determining factors, among which the spot market price. Electricity demand is influenced by a great deal of factors. As electricity is used as an input to many production processes, demand is partly determined by the characteristics of these processes, such as time of day, banking and religious holidays and the summer holidays. Economic growth and technical change are other determinants of production processes influencing electricity demand. Weather also affects electricity demand, particularly through the use of air conditioning on hot days and lighting equipment in the winter months of the year.

We estimate a function explaining total system load on an hourly basis from the spot market price and several other factors affecting energy demand. We limit our analysis to

[5] Water supply (BIC 17000), steel tubes (BIC 22200), copper, brass and other copper alloys (BIC 22460), ceramic goods (BIC 24890) and Hand tools and finished metal goods (BIC 31600).

[6] Op. cit., p. 40.

peak-load use only, as demand response during peak hours is relevant for security of supply. In order to capture the general daily demand pattern, we use time of day dummies as time-specific constants in the equation. We use a variable labeled 'maximum day temperature' to capture the influence of temperature on the energy use by air-conditioning equipment. We also constructed a cross term between maximum temperature and a 'noon to 4 PM' dummy to reflect the fact that air-conditioning units are used mainly during the hottest hours of the day.

Apart from its influence on air-conditioning equipment, the weather also affects the demand for lighting. We proxy this effect using a daylight variable, constructed as the quadratic difference from the longest day (measured in days). Cross terms with early and late hours are constructed in order to correctly represent their effect on electricity use, being the extra use of lights during dark morning and evening hours.

We constructed a trend variable, which counts days from January 1st, aiming to represent the combined effect of ongoing phenomena, such as economic growth (+) and technical progress (−) on electricity demand. Summer holidays also influence electricity use through reduced economic activity. In the Netherlands, summer holidays are differentiated over three regions; North, South and Centre. As the summer holidays in the Centre region overlaps with those in both other regions, no dummy is added here. A dummy for 'week 53' reflects that many companies are closed in the week between Christmas and New Year's day.

In order to understand the pricing mechanisms in the electricity market, let us devote some attention to how electricity is traded. Many European countries have a so-called spot market for electricity. Buyers and sellers of electricity bid their offers 24 h ahead of delivery. Prices are set on an hourly basis. After the spot market has closed, trade volumes for the following day are known. Note that suppliers at the spot market are not necessarily producers of electricity. Large users who have contracted a fixed amount of electricity may want to sell their electricity on the spot market if the price is high enough. A similar feature may be found on the demand side of the spot market. Producers who have sold more electricity in advance than they actually produce may purchase the deficit at the spot market. The above implies that trade volumes on the spot market do not represent demand.

The spot market often represents just a small part of all electricity trade. The lion's share of electricity is traded through bilateral contracts between users and suppliers. This is sometimes also referred to as the over-the-counter (OTC) market. The contents of bilateral contracts are in general undisclosed information. Some of those contracts have fixed prices, others may be linked to the spot market price, either real-time or based on averages over time. Small end-users are supplied by retailers, often on bilateral contracts with standardised terms and a fixed per unit price. They do not observe real-time prices and can therefore not respond to them.

It makes sense to look at the elasticity of total demand to the spot price. This approach captures both the effects in the spot market itself as well as the effects on the OTC contracts with prices linked to the spot price. Furthermore, we avoid the measurement problems related to distinguishing between demand and supply on the spot market. One should keep in mind however that the price elasticity found depends on the amount of demand that is subject to the spot price. If the relative importance of the spot market as a pricing mechanism increases, the demand elasticity will increase as well.

Estimating the relationship between prices and quantity constitutes a specific difficulty because demand fluctuates greatly under influences other than prices. This causes the demand curve to shift along the supply curve, causing correlation between the price variable and the error

Table 3
Descriptives

	Mean	S.D.	Min	Max
Load (MW)	14.24	1.21	9.75	17.87
Spot market price (€/MWh)	95.15	172.59	13.00	2000.00
Maximum temperature (°C)	10.31	7.00	−7.80	25.70
Daylight	10,957.09	9851.552	1	37,249

term. We solve this problem by estimating a two stage least square regression, using lagged price as an instrumental variable for price.[7]

5. Data and empirical results

Our data relate to 2003 energy use and price figures from the Netherlands. We proxy demand by the load figures published at the website of the Tennet, the Dutch TSO.[8] As stated before, we limit ourselves to peak load periods, defined here as working days from 9 AM to 6 PM. Load data are available on the basis of 15-min intervals, but we aggregate these figures to hourly data in order to use them in the same analysis as our other data. Spot market prices are published on an hourly basis at the website of the Amsterdam Power Exchange.[9] The variable 'maximum day temperature' is retrieved from the website of the Dutch meteorological institute, KNMI.[10] Table 3 below lists the descriptive of the most important non-dummy variables.

Table 4 presents the results from our empirical estimation, using both a linear and a loglinear approach.

Both equations give a similar image of energy demand, though the influence of the spot market price is quite different. The linear specification implies a price elasticity of −0.0014, whereas a price elasticity of −0.0043 follows from the loglinear specification.[11] In both cases the elasticity is low compared to the elasticities presented in Tables 1 and 2, and closer to the figures provided by Patrick and Wolack (1997), which is what was to be expected, as their results represent real-time elasticities, as do our results.

6. Implications and conclusions

The empirical literature suggests that demand elasticities for electricity are generally low. The real-time elasticity found in our analysis is even lower. Note that we look at total demand versus the spot market price. Keeping in mind that the trade volume at the spot market is approximately 15% of total load, we may get a rough idea of the order of magnitude of the price elasticity in the spot market by dividing the elasticity from our result by 0.15. The resulting figure of −0.029 (for the loglinear relationship) is still quite low, especially if we consider that users currently trading at the spot market are likely to be more price sensitive than users who voluntarily refrain from trading at the spot market.

[7] For optimal efficiency, all other explanatory variables are used as instruments as well.
[8] www.tennet.nl.
[9] www.apx.nl.
[10] www.knmi.nl.
[11] Computed standard deviations for these parameters are $1.54*10^{-3}$ and $1.59*10^{-3}$ respectively.

Table 4
Estimation results for load

Variable	Linear specification		Loglinear specification	
	Coefficient	*t*-Statistic	Coefficient	*t*-Statistic
Price (€/MWh) [a]	−0.000218	−2.3	−0.0043	−2.7
Trend [a]	0.0074	34.8	0.103	43.8
Time of day dummies, hour starting at:				
9 AM	12.203	134.1	2.044	113.8
10 AM	13.182	177.7	2.182	162.0
11 AM	13.329	179.5	2.192	162.0
Noon	13.176	173.6	2.180	158.5
1 PM	12.924	170.4	2.162	159.1
2 PM	12.995	171.3	2.167	159.0
3 PM	12.826	169.1	2.155	159.0
4 PM	12.581	165.8	2.137	158.6
5 PM	12.499	137.4	2.143	161.6
6 PM	11.907	130.9	2.010	114.7
Day of week dummies				
Thursday	0.1877	5.7	0.012	5.1
Friday	0.1734	5.2	0.010	4.2
Month of year dummies				
January	−0.7889	−11.0	0.075	11.2
February	−0.4442	−6.6	0.012	2.5
April	0.6621	12.5	0.043	11.3
July	−0.9966	−11.1	−0.079	−12.5
September	−0.5165	−10.2	−0.049	−13.7
October	−0.4053	−8.2	−0.037	−10.3
Weather variables				
Maximum day temperature	0.01264	3.4		
Maximum day temperature times noon 4 PM dummy [a]	0.02374	5.7	0.0018	7.5
Daylight times 9 AM dummy [a]	0.00002	5.3	0.0102	6.6
Daylight times 5 PM dummy	0.00002	3.4		
Daylight times 6 PM dummy [a]	0.00006	13.3	0.0150	9.6
Holiday dummies				
Summer holidays North (dummy)	−0.372	−4.2	−0.024	−4.0
Summer holidays South (dummy)	−0.176	−3.5	−0.023	−6.8
Week 53 (dummy)	−1.210	−9.8	−0.073	−8.3
Adjusted R^2		0.726		0.738
No. of observations		2500		2500

[a] Log of variable in loglinear specification.

If the result holds for the entire market, the following implications may be derived. First, a low (constant) elasticity implies that even small amounts of market power may lead to very high welfare transfers. On the other hand, welfare losses because of market power will be relatively small, as price increases have a limited real-time effect on electricity demand.

Note that this applies to short temporary increases, implying that the transfers from market power come in the form of scarcity rents. With low real-time elasticities, peak prices and scarcity rents may reach very high levels. Apart from the welfare transfers they create, high scarcity rents also give rise to profitable investments in spare capacity. This implies that government intervention on the supply side may not be necessary, and may even lead to substantial free riding.

If the real-time elasticity computed above applies to all users, it also implies that security of supply policies aimed at increasing the awareness of real-time prices (such as capacity subscriptions) may not be very effective, as customers may not be willing to react to real-time prices at all.

We would like to emphasize however that these conclusions are conditional on the assumption that the elasticity found here applies to all consumers. The validity of this assumption does not follow from our analysis and should be tested empirically, for instance through controlled experiments. The main policy implication is that the real-time elasticity of targeted users should be assessed before expensive demand response measures are taken on a large scale.

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Issuer Credit Rating							
Local Currency LT	A	02/19/2016	07/07/2020	A	CreditWatch/Outlook	Stable	08/22/2017
Local Currency ST	A-1	02/19/2016	07/07/2020	A-2	Upgrade		
Foreign Currency LT	A	02/19/2016	07/07/2020	A	CreditWatch/Outlook	Stable	08/22/2017
Foreign Currency ST	A-1	02/19/2016	07/07/2020	A-2	Upgrade		

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PacifiCorp
Moody's Org ID: 590000 LEI: SGY07Y7FNYBNLM6Z1M11 Market Segment: Infrastructure & Project Finance
Industry: UTILITY: REG - ELEC TR - INTEGRATED Peer Group: Regulated Electric and Gas Utilities Domicile: UNITED STATES

ANALYST
Analyst: Laura Schumacher

LONG TERM RATING
Rating: A3, Not on Watch
Type: LT Issuer Rating
Date: 20 Jun 2018

SHORT TERM RATING
Rating: P-2, Not on Watch
Type: Commercial Paper - Dom Curr
Date: 20 Jun 2018

OUTLOOK
Stable
Date: 20 Jun 2018

OTHER DEBTS ON WATCH?
No

Research | Ratings | Family Tree | Peer Group | Market Signals

Issuer Research | Industry Research | Family Tree Research | Methodology

Results 1 - 34 Of 34 | Page 1 Of 1

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Date	Document Type	Title	Source
25 Jun 2020	Credit Opinion	PacifiCorp: Update to credit analysis	Moody's Investors Service
04 Nov 2019	Announcement of Periodic Review	Moody's announces completion of a periodic review of ratings of Berkshire Hathaway Energy Company	Moody's Investors Service
27 Jun 2019	Credit Opinion	PacifiCorp: Update to credit analysis	Moody's Investors Service
22 Jun 2018	Credit Opinion	PacifiCorp: Update to credit analysis	Moody's Investors Service

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July 22, 2020
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RRA Regulatory Focus

Major Rate Case Decisions - January - June 2020

For Detailed Data
Click here to see supporting data tables.

The equity returns authorized electric and gas utilities nationwide edged downward in the first half of 2020. Several rate case decisions have been delayed until later this year due to the health and economic crisis triggered by the coronavirus outbreak that brought the U.S. economy to a near halt. Based on data gathered by Regulatory Research Associates, a group within S&P Global Market Intelligence, the average return on equity authorized electric utilities was 9.55% in all rate cases decided in the first half of 2020, below the 9.65% average for cases in full year 2019. There were 27 electric ROE determinations in the first half of 2020, versus 47 in full year 2019.

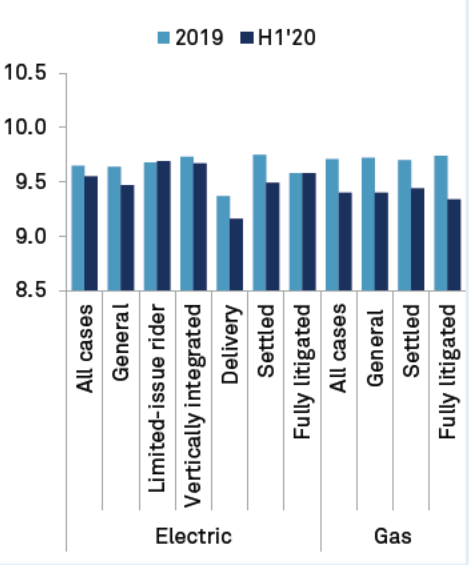
Included in those authorizations is a decision by the Maine Public Utilities Commission ordering a management inefficiency adjustment that reduced Central Maine Power Co.'s ROE by 100 basis points to 8.25% due to imprudence associated with a new billing system. The PUC ordered that this downward ROE adjustment be lifted when the utility meets all performance benchmarks for all service quality metrics for at least 18 consecutive months beginning March 1, 2020, and formally demonstrates to the commission that the problems have been resolved. Calculation of the average electric ROE without the penalty results in a 9.58% ROE for the first half of 2020.

This data includes several limited-issue rider cases. Excluding these cases, the average authorized ROE was was 9.47% in electric rate cases decided in the first half of 2020, versus 9.64% observed in full year 2019. The difference between the ROE averages including rider cases and those excluding the rider cases is driven by ROE premiums allowed in certain states for riders that address recovery of specific generation projects.

The average ROE authorized gas utilities was 9.40% in cases decided during the first half of 2020 versus 9.71% in full year 2019. There were 12 gas cases that included an ROE determination in the first six months of 2020 versus 32 in full year 2019.

The 2020 averages are hovering at the lowest levels ever witnessed in the industry, and with the recent rate cuts by the U.S. Federal Reserve and current pandemic induced recession, even lower authorized returns may be on the horizon.

Average authorized return on equity (%)
Dashboard



Electric average	2019	H1'20	
All cases	9.65	9.55	▼
General rate cases	9.64	9.47	▼
Limited-issue rider cases	9.68	9.69	▲
Vertically integrated cases	9.73	9.67	▼
Delivery cases	9.37	9.16	▼
Settled cases	9.75	9.49	▼
Fully litigated cases	9.58	9.58	
Gas average	**2019**	**H1'20**	
All cases	9.71	9.40	▼
General rate cases	9.72	9.40	▼
Settled cases	9.70	9.44	▼
Fully litigated cases	9.74	9.34	▼
U.S. Treasury	**2019**	**H1'20**	
30-year bond yield	2.58	1.62	▼

Data compiled July 20, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Lisa Fontanella, CFA
Research Director

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Sales_NorthAm@spglobal.com

Enquiries
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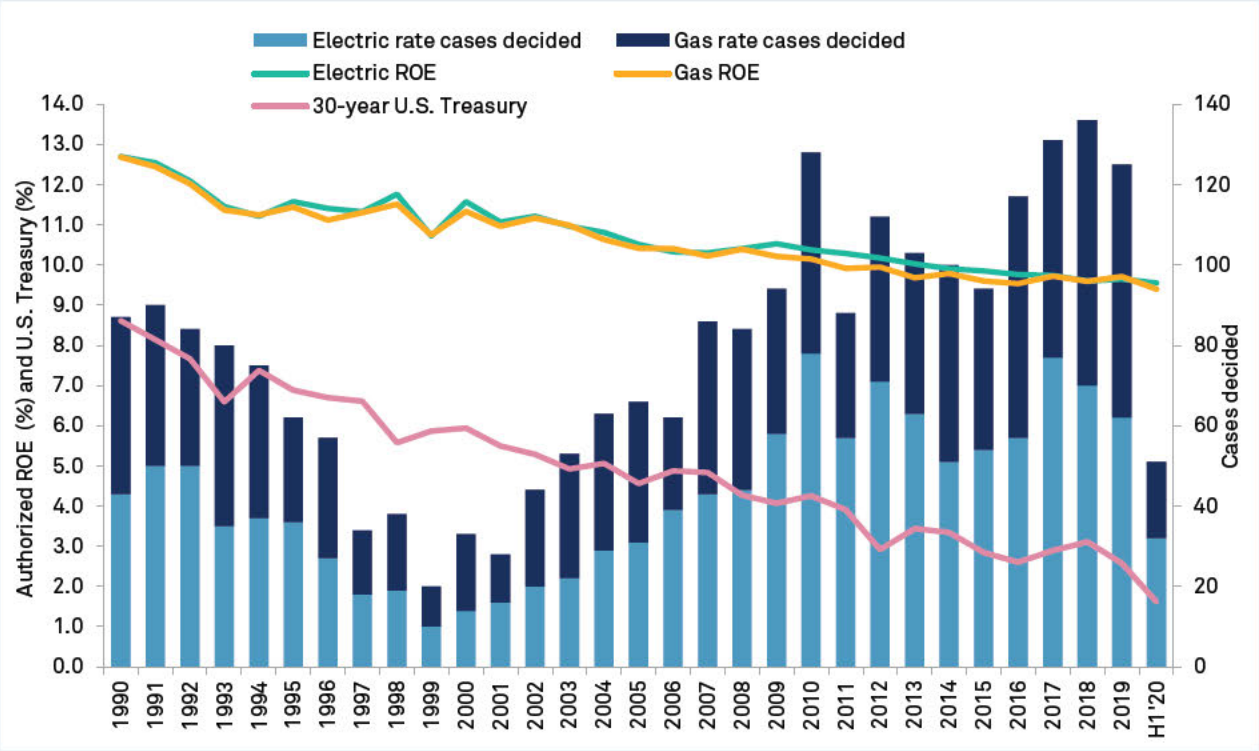
Average electric and gas authorized ROEs and number of rate cases decided



Data compiled July 20, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

In the first six months of 2020, the median ROE authorized in all electric utility rate cases was 9.45%, versus 9.60% in full year 2019; for gas utilities, the metric was 9.42% in the first half of 2020, versus 9.70% in full year 2019.

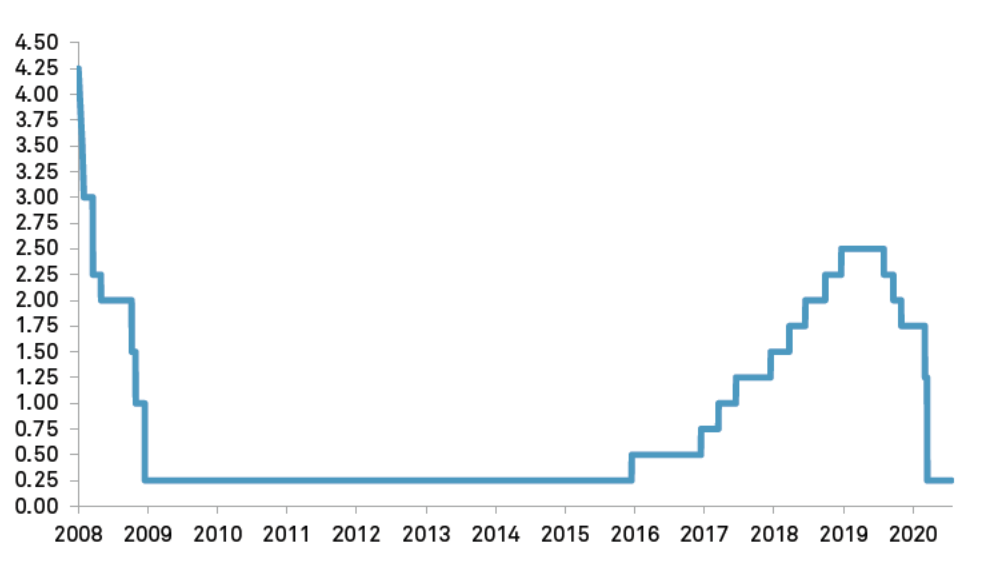
From a longer-term perspective, interest rates, as measured by the 30-year U.S. Treasury bond yield, fell almost steadily from the early 1980s until 2015 or so, placing downward pressure on authorized ROEs. Even though the decline has been less dramatic in the period since 1990, average authorized ROEs fell below 10% for gas utilities in 2011 and for electric utilities in 2014.

Since 2010, rate case activity has been robust, with 100 or more cases adjudicated in eight of the last ten calendar years. This count includes electric and gas cases where no ROEs have been specified; however, withdrawn cases are not included. After reaching an almost 30-year high in 2018, when almost 140 cases were decided, rate case activity moderated somewhat in 2019, with about 125 electric and gas cases resolved. Currently, there are about 90 rate cases pending; however, the current state of affairs due to COVID-19 has caused some companies to postpone rate case filings that were planned for this year. This backlog, coupled with the need to address COVID-19 pandemic-related costs and lost revenue may usher in an even more robust level of rate case activity in 2021 and beyond,

Absent the pandemic, increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity and employee benefits have contributed to an active rate case agenda over the last decade.

Rising interest rates over the past several years also likely contributed to the increased rate case activity. Beginning in 2015, the Federal Reserve began to gradually raise the federal funds rate, increasing them several times, up to 2.50% in December 2018. However, with concerns of slowing growth, fears of a global recession and the impact of U.S.-China trade tensions negatively weighing on the U.S. economy, the Fed, after more than a decade without a cut, lowered rates three times in 2019, the last reduction of which brought the federal funds rate to a range of 1.50% to 1.75%. Citing the economic fallout from the coronavirus outbreak, the Fed delivered two emergency rate cuts thus far this year, the first in early March, which cut rates by 50 basis points to 1.00% to 1.25%, and a second in mid-March, which slashed rates another 100 basis points to the current range of 0-0.25%.

Federal funds target rate, upper limit %



Data as of July 20, 2020.
Source: Federal Reserve

While changes in the federal funds rate do not move in lockstep with longer-term treasuries and authorized ROEs do not move in lockstep with interest rates, the expectation is that as interest rates change, authorized ROEs would also change in similar fashion. However, several factors impact the timing and magnitude of such a shift. Normal regulatory lag, i.e., the amount of time it takes for a utility to put together a rate case filing and tender it to the commission and then for the commission to process the case, would without any other influences delay a change in average authorized ROEs relative to interest rates.

It is also worth noting that while both interest rates and authorized ROEs have generally been declining since 1990, the gap between authorized ROEs and interest rates widened somewhat over this period, largely as a result of an often-unstated understanding by regulators that the drop in interest rates caused by Federal Reserve intervention was unusual.

Capital structure trends

To offset the negative cash flow impact of 2017 federal tax reform, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than the levels observed in 2018 and 2017. However, in cases decided during the first half of 2020, the average authorized equity ratio for electric utilities fell to 48.61%. For full years 2019, 2018 and 2017, the average equity ratios authorized in electric utility cases were 49.94%, 49.02% and 48.90%, respectively. The average allowed equity ratio for gas utilities

nationwide in cases decided in the first six months of 2020 was slightly higher than the levels observed in earlier full year periods. For the first six months of 2020, the average was 53.12%, versus 51.75% in 2019, 50.12% in 2018 and 49.88% in 2017.

Taking a longer-term view, equity ratios have generally increased over the last 15 years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis.

A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view based upon the types of proceedings/decisions in which these ROEs were established.

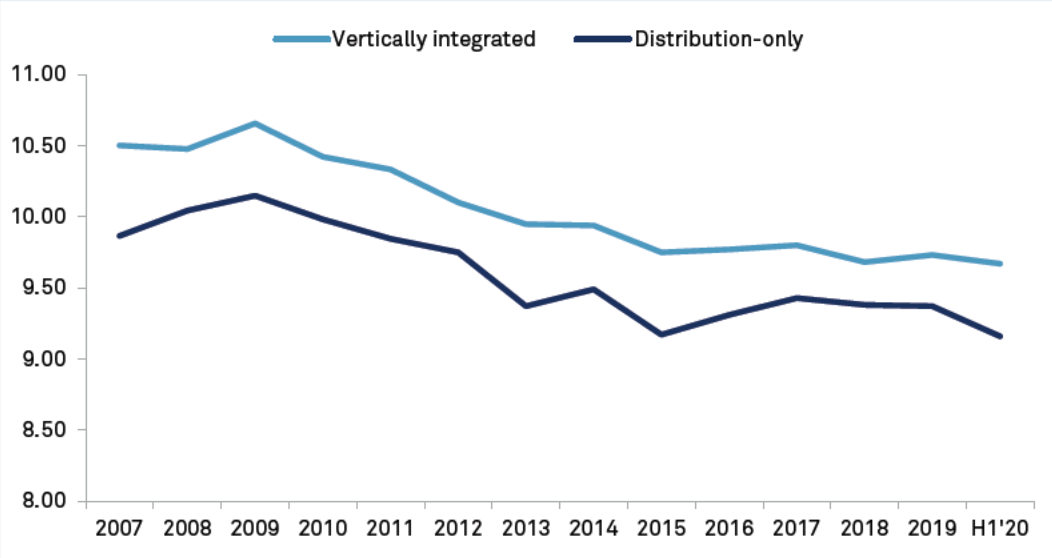
RRA has observed that there can be significant differences between the average ROEs from one subcategory of cases to another.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations.

Comparing electric vertically integrated cases versus delivery-only proceedings over the past several years, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are about 30 to 65 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.67% in cases decided during the first six months of 2020, just below the 9.73% average level posted in full year 2019. For electric distribution-only utilities, the industry average ROE authorized in the first six months of 2020 was 9.16%, versus 9.37% in full year 2019. Included within the distribution returns for the first half of 2020 is the previously mentioned penalty ordered by the Maine PUC for Central Maine Power. Absent that 100 basis point penalty, a 9.31% average ROE is calculated for distribution only utilities in the first half of 2020.

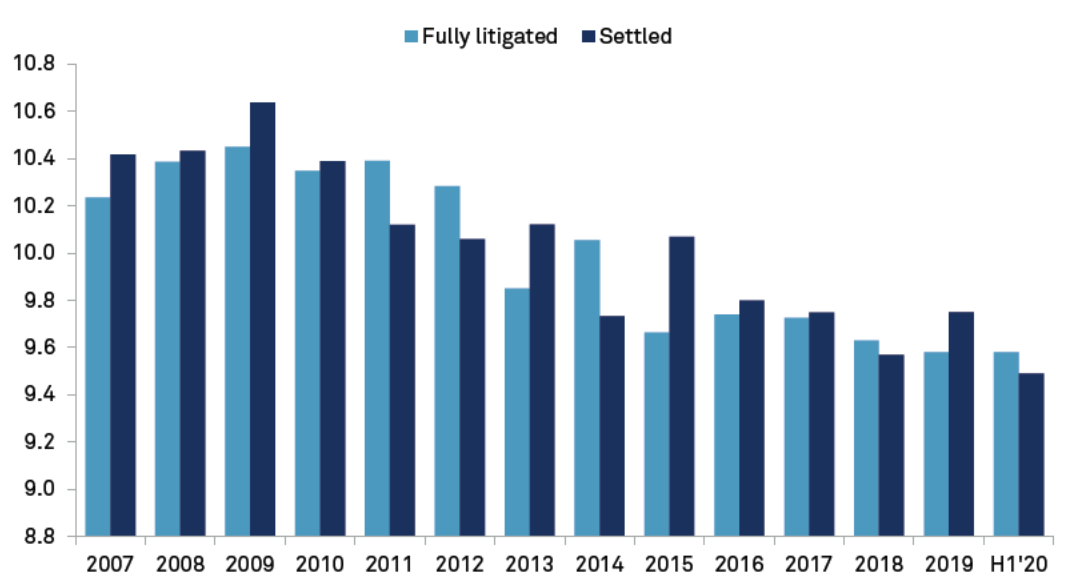
Average authorized electric ROEs (%)



Data compiled July 20, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

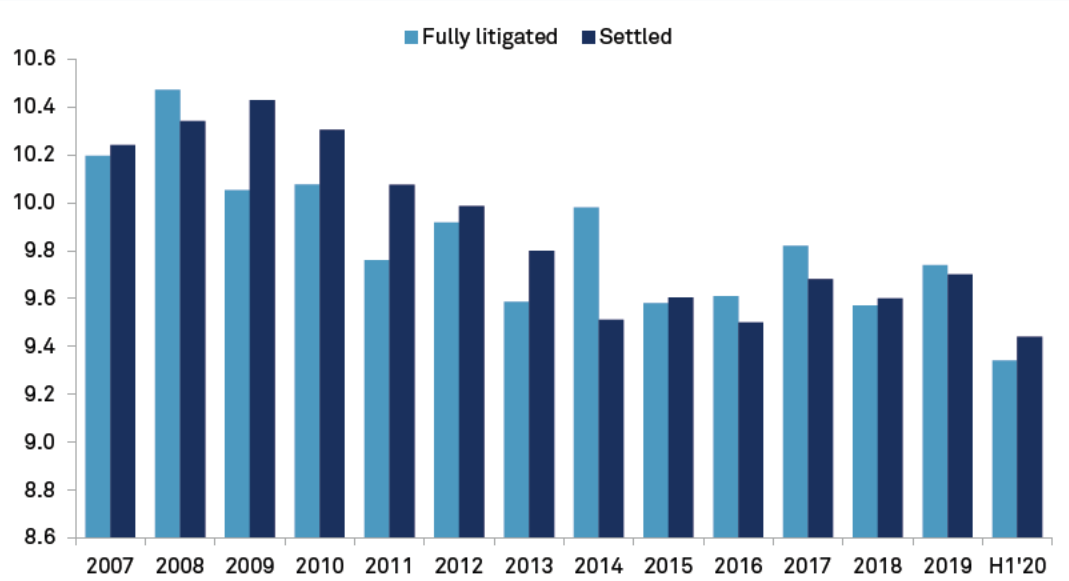
Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. However, some states preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

Average authorized electric ROEs, settled versus fully litigated cases (%)



Data compiled July 20, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Average authorized gas ROEs, settled versus fully litigated cases (%)



Data compiled July 20, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others, it was higher for settled cases, and in a handful of years, the authorized ROE was similar for both fully litigated and settled cases.

Over the last several years, the annual average authorized ROEs in electric cases that involve limited-issue riders were typically meaningfully higher than those approved in general rate cases, driven primarily by the ROE premiums authorized in generation-related limited issue rider proceedings in Virginia. Limited-issue rider cases in which a separate ROE is determined have had limited use in the gas industry, as most of the gas riders rely on ROEs approved in a previous base rate case.

The following discussion focuses on the corresponding tables available here.

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and by quarter since 2016, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and by quarter for the past six quarters.

Tables 3 and 4 provide comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in 2020 are listed in Table 5, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases that were decided during the specified time periods and are not necessarily representative of either the average currently authorized ROEs for utilities industrywide or the returns actually earned by the utilities.

Please note: In an effort to align data presented in this report with data available in S&P Global Market Intelligence's online database, earlier historical data provided in previous reports may not match historical data in this report due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed.

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CASE: UE 374
WITNESSES: MATT MULDOON-
MOYA ENRIGHT-
CURTIS DLOUHY

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1912
2020 Updates from Rating Agencies

Exhibits in Support of Rebuttal Testimony

July 24, 2020

Staff Exhibit 1912 is

Confidential

Subject to Protective Order 20-040

CASE: UE 374
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2000

Rebuttal Testimony

REDACTED
July 24, 2020

Q. Please state your name, occupation, and business address.

A. My name is Steve Storm. I am a Senior Economist employed in the Energy, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit Staff/801.

Q. What is the purpose of your testimony?

A. My testimony discusses certain issues related to the following topics:

- Repowered Wind in RAC Proceedings
- Energy Vision 2020 New Wind
- Foote Creek Repowered Wind
- Pryor Mountain New Wind
- Post-retirement Employee Benefit Plans other than Pension

Q. Did you prepare any exhibits for this docket?

A. Yes. I include Exhibit Staff/2001, consisting of one page, and Exhibit Staff/2002, also consisting of one page

Q. How is your testimony organized?

A. My testimony is organized as follows:

Summary of Recommendations 2
Issue 1, Repowered Wind in RAC Proceedings 5
Issue 2, Energy Vision 2020 New Wind and Foote Creek I Wind Repowering Projects 9
Issue 3, Pryor Mountain New Wind 19
Issue 4, Post-retirement Employee Benefit Plans other than Pension 37

SUMMARY OF RECOMMENDATIONS

Q. Please summarize the recommendations included in Staff's Rebuttal Testimony.

A. Regarding PacifiCorp's EV 2020 new wind projects and the Foote Creek I wind repowering project, Staff recommends the Commission:

1. Find PacifiCorp's decision to invest in the Ekola Flats, TB Flats I and II, and Cedar Springs II EV 2020 new wind projects and the Foote Creek I wind repowering project to be prudent, based on the assumptions and analysis performed by the Company in Docket No. LC 67, the Company's 2017 IRP, and Docket No. UM 1845, the Company's 2017R RFP proceeding associated with its renewable Action Item 1b in its 2017 IRP, if the project qualifies for 100 percent of production tax credits on its commercial operation date.
2. Cap the amount of rate base addition for each of the TB Flats 1 and II, Ekola Flats, and Cedar Springs II new wind projects and for the Foote Creek I wind repowering project to the respective amount shown for the project in Staff's Opening Testimony[1] for purposes of ratemaking in this proceeding.
3. Require PacifiCorp to provide a signed declaration from a Vice President of Pacific Power or Rocky Mountain Power attesting to each new or

[1] The value for each of the EV 2020 new wind projects is shown in confidential Table 1 at Staff/800, Storm/9 and the confidential value for the Foote Creek I wind repowering project is at Staff/800, Storm/5.

repowered wind facility having been placed in service and in commercial operation prior to its inclusion in rates.

4. Require PacifiCorp to confer with the parties to this proceeding regarding cost recovery of an EV 2020 new wind project or of the Foote Creek I wind repowering project if the project's COD, including that of necessary transmission infrastructure, is after June 30, 2021. If the project is in service on or prior to that date, but after December 31, 2020, Staff recommends allowing a rate effective date following the project's COD and receipt of a signed declaration from a Vice President of Pacific Power or Rocky Mountain Power attesting that the project has been placed in service and is in commercial operation.

Regarding PacifiCorp's Pryor Mountain new wind project, Staff recommends the Commission:

1. Find PacifiCorp's decision to invest in the Pryor Mountain new wind project to be prudent, based on the assumptions and analysis presented by the Company in this proceeding.
2. Cap PacifiCorp's investment in Pryor Mountain for purposes of ratemaking in this proceeding at no more than **[Begin Confidential]** [redacted] **[End Confidential]**.
3. Require PacifiCorp to provide a signed declaration from a Vice President of Pacific Power or Rocky Mountain Power attesting to the Pryor Mountain new wind project having been placed in service and in commercial operation prior to its inclusion in rates.

4. Require PacifiCorp to confer with the parties to this proceeding regarding cost recovery of the Pryor Mountain new wind project if the project's COD, including that of necessary transmission infrastructure, is after June 30, 2021. If Pryor Mountain is in service on or prior to that date, but after December 31, 2020, Staff recommends allowing a rate effective date following its COD and receipt of the associated attestation.

Regarding Schedule 272:

5. Open an investigation into Schedule 272 and the applicability of VRET conditions.
6. Suspend PacifiCorp's entering into new Schedule 272 individually negotiated agreements that include supplying RECs from utility-owned resources pending the outcome of such an investigation.

1 **ISSUE 1, REPOWERED WIND IN RAC PROCEEDINGS**

2 **Q. Did Staff provide a recommendation regarding the total of net book**
3 **values of the equipment replaced as part of the wind repowering**
4 **projects in UE 352?[2]**

5 A. Yes. Staff recommended the Commission:

6 Require PacifiCorp to use the lower of a) the total of net book values for
7 the replaced equipment in UE 352 as of each project's actual rate-effective
8 date or b) the approximate $157 million referenced in Order No. 19-304[3]
9 and its Appendix A to calculate the appropriate amount of the replaced
10 equipment's net book value for ratemaking purposes in this proceeding.

11 **Q. Did any Intervenor discuss this issue in Opening Testimony?**

12 A. No, although AWEC's Opening Testimony discussed a related issue. AWEC
13 asserted that PacifiCorp did not remove an approximate $157 million, which
14 value represents the aggregate net book value of the equipment replaced as
15 part of the wind repowering projects that were the subject of UE 352, as of the
16 time of each project's rate effective date, in calculating depreciation expense
17 for the purpose of ratemaking in the proceeding at hand.[4]

18 Staff's issue is related, but instead involves the actual amount used by
19 PacifiCorp as the aggregated net book balance of the replaced equipment, as
20 of the time of each project's rate effective date, as an offset to the non-

[2] UE 352 was PacifiCorp's 2019 Renewable Adjustment Clause (RAC) proceeding.
[3] Order No. 19-304 was the Order in UE 352 that adopted a stipulation amongst all parties.
[4] AWEC/100, Mullins/10-11.

1 protected EDIT balance for the purposes of ratemaking in the proceeding at
2 hand. A higher net book value for the replaced equipment means higher
3 customer rates as a result of this proceeding, as a higher net book value (an
4 amount customers owe to PacifiCorp) reduces the net amount PacifiCorp owes
5 to customers for non-protected excess deferred income taxes (EDIT) due to
6 the Tax Cut and Jobs Act, which was used to offset ("pay-off") the replaced
7 equipment's net book value.[5]

8 **Q. Did PacifiCorp discuss this Staff issue in the Company's Reply**
9 **Testimony?**

10 A. Yes. The Company asserted it "used the same net book value on a total-
11 company basis in Adjustment 8.13, Repowering Projects Capital Addition, as
12 the total-company amount filed in docket UE 352,"[6] and that this amount
13 equals the value in PacifiCorp's response to AWEC Data Request 009 in
14 UE 352,[7] "which is the basis for the $157 million Oregon-allocated amount."[8]

15 **Q. What does Staff calculate as the total of values by wind resource in**
16 **PacifiCorp's response to AWEC Data Request 009 in UE 352?**

17 A. Staff calculates this as $ 587,094,257 on a system basis.

18 **Q. What was the value of the SG factor used in UE 352 to allocate**
19 **generation costs to individual states?**

---

[5] See; e.g., Section 18 (lines 1 – 12 on page 4) of the Stipulation amongst Parties in UE 352.
[6] PAC/3100, McCoy/49.
[7] Staff includes PacifiCorp's response to AWEC's Data Request 009 as Exhibit Staff/2001.
[8] PAC/3100, McCoy/49.

1 A. The value of the SG factor PacifiCorp used in UE 352 to allocate generation
2 costs to Oregon was 26.7248 percent.[9] Using this value, Staff calculates the
3 amount of net book value to be allocated to Oregon as $156,899,766, or
4 approximately $156.9 million.
5 **Q. What did PacifiCorp say in Reply Testimony is the appropriate value of**
6 **the SG allocation factor to use for ratemaking in the proceeding at hand?**
7 A. PacifiCorp asserted the value SG factor it used to allocate generation costs to
8 Oregon in this proceeding is 26.023 percent.[10]
9 **Q. What is the result of multiplying the Oregon SG factor value PacifiCorp**
10 **used in this proceeding (26.023 percent) by the value Staff obtained from**
11 **aggregating the individual repowering project values above of**
12 **$156,899,766?**
13 A. Staff calculates this as approximately $152.8 million.
14 **Q. What did PacifiCorp say in Reply Testimony is the value it used for**
15 **ratemaking in this proceeding?**
16 A. PacifiCorp stated that the Oregon-allocated value, calculated using the same
17 value for the SG factor for Oregon used elsewhere in this proceeding for
18 purposes of ratemaking, was $153 million.
19 **Q. How does Staff view this value?**
20 A. Staff concurs with PacifiCorp's statement that the aggregate net book value for
21 the equipment replaced in the UE 352 wind repowering projects shown in

[9] Exhibit PAC/401, McDougal/1.
[10] PAC/3100, McCoy/50.

1 PacifiCorp's response to AWEC data request 009 in UE 352, multiplied by the
2 Oregon SG factor value used in UE 352, is approximately $157 million and
3 that, when multiplied by the Oregon SG factor value used in the current
4 proceeding, is approximately $153 million.[11] As a result, Staff withdraws its
5 recommendation regarding the appropriate balance to be used for ratemaking
6 in the proceeding at hand for the net book value of the replaced equipment in
7 the UE 352 wind repowering projects made in Staff's Opening Testimony.[12]

[11] PAC/3100, McCoy/50.

[12] See; e.g., Staff/800, Storm/5-6.

1 **ISSUE 2, ENERGY VISION 2020 NEW WIND AND FOOTE CREEK I WIND**
2 **REPOWERING PROJECTS**

3 **Q. Did Staff provide a recommendation regarding the Energy Vision 2020**
4 **New Wind (EV 2020 New Wind) projects and the Foote Creek I wind**
5 **repowering project?**

6 A. Yes. The EV 2020 New Wind projects included PacifiCorp's Ekola Flats,
7 TB Flats I and II, and Cedar Springs II EV 2020 new wind projects. Staff
8 provided recommendations for Foote Creek I separate from those associated
9 with the EV 2020 New Wind projects in its Opening Testimony.

10 **Q. What do these two sets of Staff's recommendations have in common?**

11 A. Staff's recommendations in Opening Testimony for each set of projects were
12 as follows:

13 • Find PacifiCorp's decision to invest in each of these projects to be prudent,
14 although on slightly different bases, assuming the projects qualify for
15 100 percent of production tax credits (PTC).
16 • Cap the investment for each individual project at a specified level specified
17 in Staff's Opening Testimony, which values reflect those provided by
18 PacifiCorp.[13]
19 • Require signed declarations from either a Vice President of Pacific Power
20 or Rocky Mountain Power attesting to each new or repowered wind project

[13] The maximum investment values ("cap") by project appear in Staff's confidential Table 1 at Staff/800, Storm/9 for the TB Flats I and II, Ekola Flats, and Cedar Springs II projects, and in the specific recommendation (e.g., Staff/800, Storm/5) for the Foote Creek I project (as a confidential value). See Staff's citation for the source of Table 1 values at Staff/800, Storm/9 and the citation for the source of the Foote Creek I capital cost at Staff/800, Storm/57.

having been placed in service and in commercial operation prior to January 1, 2021.

- Require PacifiCorp to refile for cost recovery of the EV 2020 new wind and associated transmission projects (such as the Aeolus-to-Bridger/Anticline transmission project) if any project's Commercial Operation Date (COD) is after December 31, 2020. Staff's analogous recommendation for the Foote Creek I wind repowering project recommended the Commission require PacifiCorp to refile for cost recovery of that project if its COD, including that of necessary transmission infrastructure, is after December 31, 2020.

Q. Did Parties other than Staff discuss either the EV 2020 new wind projects or the Foote Creek I wind repowering project in Opening Testimony?

A. Yes. AWEC discussed the Energy Vision 2020 (EV 2020) new wind projects in Exhibit AWEC/100.

Q. What was a key AWEC point regarding the EV 2020 new wind projects?

A. AWEC noted that these projects were selected through an RFP process that was originally proposed in PacifiCorp's 2017 IRP and that PacifiCorp did not identify a need for new resources throughout the IRP process, disclosing "a major effort to repower most of its existing wind resources, acquire substantial new wind resources, and accelerate the construction of a portion of its Energy Gateway West transmission line" in the public meeting held on March 2 and 3, 2017.[14]

[14] AWEC/100, Mullins/13.

1 **Q. Did AWEC support, in the 2017 RFP proceeding associated with**
2 **PacifiCorp's 2017 IRP renewable action items,[15] Commission**
3 **acknowledgment of the EV 2020 new and repowered wind projects?**
4 A. No. AWEC's Opening Testimony stated that, while it recommended the
5 Commission decline to acknowledge the final short list in the related RFP
6 proceeding,[16] AWEC's Opening Testimony restated in its "Comments of ICNU
7 on IE Report" that it would "likely support inclusion of [the IE's] conditions as
8 part of a prudency determination" in a latter rate case."[17]
9 **Q. What did AWEC recommend in its Opening Testimony?**
10 A. AWEC recommended the Commission:
11 1. Impose a minimum capacity factor for each EV 2020 [new wind] project at
12 their modeled capacity factors in the RFP. Additionally, after "several years
13 of performance, if average actual capacity factors exceed what was
14 modeled in the RFP, PacifiCorp would implement the higher capacity factor
15 in forecasting power costs in the Company's annual Transition Adjustment
16 Mechanism."[18]
17 2. Order a similar adjustment be applied in the Power Cost Adjustment
18 Mechanism, to apply over a rolling 5-year period.[19]

[15] PacifiCorp's 2017 IRP proceeding was docketed as LC 67.
[16] Docket No. UM 1845.
[17] AWEC/100, Mullins/18. ICNU was a predecessor organization to AWEC.
[18] AWEC/100, Mullins/19.
[19] Ibid.

1 AWEC stated that these recommendations addressed the risk of economic
2 benefits included in PacifiCorp's economic analysis of these projects, and that
3 AWEC continued to support the Oregon IE's recommended conditions in the
4 RFP proceeding, which addresses risks associated with the cost of the
5 EV 2020 projects.[20] AWEC asserted its recommendations, "as well as the
6 others associated with the cost of the EV 2020 projects," align with the
7 Commission's conditions on acknowledgement of the 2017 IRP.[21]

8 **Q. Did PacifiCorp address Staff's and AWEC's discussion and**
9 **recommendations regarding the EV 2020 new wind projects in its Reply**
10 **Testimony?**

11 A. Yes. The Company stated that "[t]he Commission should reject setting
12 individual cost caps for these projects," and asserted that capping costs of the
13 EV 2020 projects "would penalize the Company for any increase in costs, if
14 any, attributable to the COVID-19 pandemic, an event it could not have
15 foreseen."[22]

16 **Q. Did PacifiCorp, in its Reply Testimony, state that it would self-impose a**
17 **cost cap for each of these projects for purposes of ratemaking in the**
18 **proceeding at hand?**

19 A. Yes. The Company, while stating that it "should recover its full cost of service
20 related to the projects on which Mr. Storm and Mr. Mullins seek to impose cost

[20] AWEC/100, Mullins/18-20.
[21] AWEC/100, Mullins/20.
[22] PAC/2000, Wilding/22-23.

1 caps," included that "[i]n this case, PacifiCorp will not seek more than the
2 amounts included in its initial filing," and that recovery of any increase over
3 these costs would be part of a subsequent rate case and subject to a separate
4 prudence review.[23]

5 **Q. Did PacifiCorp, in Reply Testimony, identify each specific project for**
6 **which it was self-imposing a cost cap in this proceeding?**

7 A. Yes. The Company specifically identified the EV 2020 new wind projects,
8 which includes the TB Flats I and II projects, the Ekola Flats project, and the
9 Cedar Springs II project; the Pryor Mountain new wind project; the Foote
10 Creek I repowering project; and the "D.2 segment of the Energy Gateway
11 transmission project."[24, 25]

12 **Q. Did PacifiCorp's Reply Testimony discuss Staff's recommendation that**
13 **the Commission require the Company to refile for cost recovery of the**
14 **EV 2020 new wind projects and the Foote Creek I wind repowering**
15 **project, including each project's necessary transmission infrastructure,**
16 **if a project is not in service prior to January 1, 2021?**

17 A. Yes. The Company stated that this recommendation by Staff "seems punitive
18 in that the delays associated with the COVID-19 pandemic are out of the
19 Company's control and the Company is trying to mitigate any impacts."[26]

20 **Q. Does Staff believe its recommendation is punitive?**

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[23] PAC/2000, Wilding/23.
[24] PAC/2000, Wilding/21.
[25] Staff's Rebuttal Testimony discusses transmission projects in Exhibit Staff/2100.
[26] PAC/2000, Wilding/23-24.

A. No. Staff did not incorporate any potential impacts of the Internal Revenue Service's late May 2020 Notice 2020-41 regarding extension of Continuity Safe Harbor timeframes into its recommendations in Opening Testimony due to uncertainty regarding the applicability of such extensions to certain PacifiCorp new and repowered wind projects. Staff did and continues to believe a requirement that the Company refile for cost recovery for each EV 2020 new wind or Foote Creek I repowering wind project that does not qualify for 100 percent of PTC benefits is eminently reasonable, as the economics of the project would change substantially. PacifiCorp's Reply Testimony included the Company's assurance that "wind projects must be in service prior to *January 1, 2022*, in order to qualify for the full value of PTCs."[27]

Q. Did PacifiCorp identify the specific projects to which this portion of its Reply Testimony applies?

A. Yes. This assurance applies to the following "new wind" and repowered wind projects: the TB Flats I, TB Flats II, Ekola Flats, and Cedar Springs II new wind projects, and the Foote Creek I repowering project.[28]

Q. What is PacifiCorp's position regarding Staff's position that the prudence of these projects is contingent upon the facility qualifying for PTC benefits?

[27] PAC/2700, Hemstreet/8. Emphasis added by Staff.

[28] PAC/2700, Hemstreet/2.

1 A. PacifiCorp stated that "[t]he Company accepts Mr. Storm's recommendation
2 that the prudence of the New Wind Projects and Foote Creek I repowering
3 project is contingent upon the facilities qualifying for PTC benefits."[29]
4 **Q. Did PacifiCorp qualify that this statement refers to a facility qualifying**
5 **not just for PTC benefits, but specifically for 100 percent of PTC**
6 **benefits?**
7 A. No; it did not.
8 **Q. What did PacifiCorp propose regarding this issue?**
9 A. PacifiCorp proposed that, if an EV 2020 new wind project or the Foote Creek I
10 repowered wind project is "delayed beyond its rate effective date of January 1,
11 2021, the Company would be allowed to include [it] in rates once it reaches
12 commercial operating without affective the rate effective date for all other
13 components of this case," and that this could be accomplished with the use of
14 a tariff rider.[30]
15 **Q. Does Staff modify its recommendation regarding PacifiCorp having to**
16 **refile for cost recovery if an EV 2020 new wind project or the Foote**
17 **Creek I repowered wind project, including necessary transmission**
18 **infrastructure, is not in service prior to January 1, 2021?**
19 A. Yes. Staff believes there is a reasonable "middle ground," after which the
20 Company should be required to refile for rate recovery in order to address

[29] PAC/2700, Hemstreet/8.
[30] Ibid.

potentially changed costs and benefits, or at least confer with parties regarding their support for rate recovery that would begin later than June 30, 2021.

Staff now recommends the Commission require PacifiCorp to confer with the parties to this proceeding regarding cost recovery of an EV 2020 new wind project or of the Foote Creek I wind repowering project if the project's COD, including that of necessary transmission infrastructure, is after June 30, 2021. If the project is in service on or prior to that date, but after December 31, 2020, Staff recommends allowing a rate effective date following the project's COD and receipt of a signed declaration from a Vice President of Pacific Power or Rocky Mountain Power attesting that the project has been placed in service and is in commercial operation.

Q. Did PacifiCorp, in its Reply Testimony, commit to updating the COD for the EV 2020 new wind and the Foote Creek I wind repowering projects in its Surrebuttal Testimony?

A. Yes. PacifiCorp stated that the Company "will provide an update on any potential projects delays in [its] surrebuttal testimony."[31] Staff understands this as applying to the EV 2020 new wind projects and the Foote Creek I wind repowering project.

Q. What does Staff recommend to the Commission regarding the EV 2020 new wind projects and the Foote Creek I wind repowering project?

A. Staff recommends the Commission:

[31] PAC/2700, Hemstreet/7.

1. Find PacifiCorp's decision to invest in the Ekola Flats, TB Flats I and II, and Cedar Springs II EV 2020 new wind projects, and the Foote Creek I wind repowering project to be prudent, based on the assumptions and analysis performed by the Company in Docket No. LC 67, the Company's 2017 IRP, and Docket No. UM 1845, the Company's 2017R RFP proceeding associated with its renewable Action Item 1b in its 2017 IRP, if the project qualifies for 100 percent of production tax credits on its commercial operation date.
2. Cap the amount of rate base addition for each of the TB Flats 1 and II, Ekola Flats, and Cedar Springs II new wind projects, and for the Foote Creek I wind repowering project to the respective amount shown for the project in Staff's Opening Testimony[32] for purposes of ratemaking in this proceeding.
3. Require PacifiCorp to provide a signed declaration from a Vice President of Pacific Power or Rocky Mountain Power attesting to each new or repowered wind facility having been placed in service and in commercial operation prior to its inclusion in rates.
4. Require PacifiCorp to confer with the parties to this proceeding regarding cost recovery of an EV 2020 new wind project or of the Foote Creek I wind repowering project if the project's COD, including that of necessary transmission infrastructure, is after June 30, 2021. If the project is in

[32] The value for each of the EV 2020 new wind projects is in confidential Table 1 at Staff/800, Storm/9 and the confidential value for the Foote Creek I wind repowering project is at Staff/800, Storm/5.

1 service on or prior to that date, but after December 31, 2020, Staff
2 recommends allowing a rate effective date following the project's COD and
3 receipt of a signed declaration from a Vice President of Pacific Power or
4 Rocky Mountain Power attesting that the project has been placed in service
5 and is in commercial operation.

ISSUE 3, PRYOR MOUNTAIN NEW WIND

Q. Did Staff provide recommendations in its Opening Testimony regarding PacifiCorp's Pryor Mountain new wind project?

A. Yes. Staff's Opening Testimony recommended the Commission:

1. Find PacifiCorp's decision to invest in the Pryor Mountain new wind project to be prudent, based on the assumptions and analysis presented by the Company in this proceeding.
2. Cap PacifiCorp's investment in Pryor Mountain for purposes of ratemaking in this proceeding at no more than **[Begin Confidential]** [redacted] **[End Confidential].**
3. Require PacifiCorp to provide a signed declaration from a Vice President of Pacific Power or Rocky Mountain Power attesting to the Pryor Mountain new wind project having been placed in service and in commercial operation prior to January 1, 2021.
4. Require PacifiCorp to refile for cost recovery of the Pryor Mountain new wind project if the project's COD, including that of necessary transmission infrastructure, is after December 31, 2020.
5. Direct PacifiCorp to address why similar projects acquired to serve Schedule 272 customers are either not appropriately considered as part of a Voluntary Renewable Energy Tariff (VRET), or are consistent with applicable VRET guidelines, in any future ratemaking proceeding in which cost recovery for a Schedule 272 project is requested.

1 **Q. Did Intervenors discuss the Pryor Mountain new wind project in Opening**
2 **Testimony?**
3 A. Yes. The Oregon Citizens' Utility Board (CUB) discussed concerns it had
4 regarding two aspects of this project: customers' risk associated with the
5 project's modeled benefits, and whether the project represented a least
6 cost/least risk investment made on behalf of PacifiCorp's customers.
7 **Q. Please summarize CUB's concerns regarding customers' risk associated**
8 **with the project's modeled benefits.**
9 A. CUB's concerns regarding risk and Pryor Mountain's benefits to customers fall
10 into three areas: risk associated with realizing the forecasted level of
11 Production Tax Credits (PTC); risks associated with PacifiCorp's contract with
12 Vitesse for the Renewable Energy Credits (RECs); and risks associated with
13 realization of the terminal value of the facility modeled by PacifiCorp.
14 **Q. Please outline CUB's concern regarding customers' risk and realization**
15 **of PTC.**
16 A. This CUB concern involved the impact of potential construction delays beyond
17 December 31, 2020, and the Internal Revenue Service's (IRS) providing an
18 additional year by which wind projects meeting the Safe Harbor requirements
19 must be in service to realize 100 percent of the PTC value.[33] CUB noted that,
20 according to PacifiCorp, Pryor Mountain was "on schedule to be in service by
21 December 31, 2020,"[34] and stated that PacifiCorp faced a challenging

[33] CUB/100, Jenks/47-48.
[34] CUB/100, Jenks/48, citing PAC/700 Link/71.

1 timeframe in which to complete the Pryor Mountain project in the context of the
2 COVID-19 pandemic.[35]

3 **Q. Please outline CUB's concern regarding PacifiCorp's contract with**
4 **Vitesse.**

5 A. CUB asserted that, "[b]y locking in a contract for the sale of RECs to one party
6 for a period of 25 years, PacifiCorp is placing risk on its customers,"[36] and
7 noted that Facebook (the corporate parent of Vitesse) "has only existed for
8 16 years..."[37] In a nutshell, CUB's concern here is whether "the anticipated
9 benefit from the sale of RECs to Vitesse will be greater than the benefit
10 PacifiCorp could have received for customers absent the contract."[38]

11 **Q. Please outline CUB's concern regarding customers' realizing the**
12 **terminal benefit from Pryor Mountain projected by PacifiCorp.**

13 A. CUB acknowledged there may be a positive terminal value at the end of a
14 wind generating facility's economic life, but was concerned about the
15 magnitude of terminal benefit in PacifiCorp's modeling of the project.[39] CUB
16 stated its concern that "a large portion of projected customer benefits will not
17 be apparent until 2050."[40] Additionally, CUB noted that it is uncertain "whether
18 wind generation will even be valuable"[41] 30 years in the future.

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[35] CUB/100, Jenks/48.
[36] CUB/100, Jenks/50.
[37] Ibid.
[38] Ibid.
[39] CUB/100, Jenks/51.
[40] Ibid.
[41] CUB/100, Jenks/53.

1 **Q. Please outline CUB's concern regarding whether Pryor Mountain**
2 **represents a least cost/least risk investment.**
3 A. CUB noted that, with PacifiCorp selling all RECs associated with Pryor
4 Mountain's output, "other cost-of-service customers are essentially procuring a
5 brown resource with a variable load shape."[42] CUB noted that, as Pryor
6 Mountain has a 30-year depreciable life, and PacifiCorp's contract with Vitesse
7 is for 25 years, other cost-of-service customers will receive "bundled
8 renewable energy from the facility for its last five years,"[43] when the value of
9 the produced RECs is uncertain.
10 **Q. What did CUB recommend to the Commission regarding Pryor**
11 **Mountain?**
12 A. CUB's recommendation included that PacifiCorp should "put additional
13 evidence on the record in its Reply Testimony to justify its position that Pryor
14 Mountain will be operational by December 31, 2020, and address whether the
15 recent IRS Notice provides assurance of an extra year to capture PTC
16 benefits."[44]
17 CUB stated it "would like to see evidence that supports the REC sales as
18 optimizing value for the rest of the system."[45]
19 **Q. Did CUB recommend the Commission authorize cost recovery of**
20 **PacifiCorp's Pryor Mountain facility in this proceeding?**

[42] Ibid.
[43] CUB/100, Jenks/54.
[44] CUB/100, Jenks/49.
[45] CUB/100, Jenks/50.

A. CUB recommended against the Commission allowing PacifiCorp cost recovery for its Pryor Mountain investment and stated its desire for the Company to address the customer risks CUB identified, "discuss whether there are ways to mitigate these risks on behalf of customers," as well as provide "more analysis showing this is a least cost/least risk resource."[46]

As part of its recommendation to the Commission, CUB noted that Pryor Mountain was not selected in the IRP to meet the resource needs of the Company and that it does not include any RECs for the system for 25 years.[47]

Q. Did PacifiCorp address these CUB concerns in its Reply Testimony?

A. Yes. Regarding CUB's and Staff's[48] concern with Pryor Mountain qualifying for 100 percent of potential PTC benefits, PacifiCorp provided an update on construction timing and the COVID-19 pandemic as these impact Pryor Mountain's Commercial Operation Date (COD).

Q. What did PacifiCorp say in its Reply Testimony regarding risk to the planned COD on or prior to December 31, 2020?

A. The Company stated that, while some aspects of the project are on schedule, it had received *force majeure* notices "from various supplies and contractors providing materials to or working on the Pryor Mountain Wind Project that their performance may be affected by COVID-19."[49] Additionally, Vestas—the

[46] CUB/100, Jenks/55.

[47] Ibid.

[48] Staff cites its concern regarding construction delays and qualification for full PTC benefits, as raised in the LC 70 PacifiCorp 2017 IRP proceeding, at Staff/800, Storm/49.

[49] PAC/2400 Van Engelenhoven/7.

supplier of Pryor Mountain's wind turbine generator (WTG) equipment—had "advised the Company of delayed delivery of some of the WTG components."[50] PacifiCorp stated in Reply Testimony that it "continues to work to deliver an in-service date of December 2020,"[51] but—if the in service date moves into 2021—Pryor Mountain will still qualify for 100 percent PTCs and that, as long as the project is placed in service by December 31, 2021, it "will qualify for 100 percent PTCs," as a result of the May 2020 Continuity Safe Harbor extension.[52]

Staff notes that PacifiCorp stated in Reply Testimony that it "will provide another update on the construction status of [the Pryor Mountain and other New Wind and Transmission] projects in surrebuttal testimony.[53]

Q. Did PacifiCorp's Reply Testimony discuss Staff's recommendation that the Commission require the Company to refile for cost recovery if the Pryor Mountain project, including necessary transmission infrastructure, if the project is not in service prior to January 1, 2021?

A. Yes, stating that this recommendation by Staff "seems punitive in that the delays associated with the COVID-19 pandemic are out of the Company's control and the Company is trying to mitigate any impacts."[54]

Q. Does Staff believe its recommendation is punitive?

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[50] Ibid.
[51] Ibid.
[52] PAC/2400, Van Engelenhoven/8.
[53] PAC/2000, Wilding/23.
[54] PAC/2000, Wilding/23-24.

1 A. No. Staff believes a requirement that the Company refile for cost recovery if
2 Pryor Mountain does not qualify for 100 percent of PTC benefits is eminently
3 reasonable, as the project's economics would change substantially.
4 PacifiCorp's Reply Testimony provides assurance that, "even if the in-service
5 date of [Pryor Mountain][55] slips to 2021, the projects will continue to be eligible
6 for 100 percent of the [PacifiCorp-forecasted] PTCs."[56]
7 **Q. What did PacifiCorp propose regarding this issue?**
8 A. PacifiCorp proposed that, "if [Pryor Mountain[57]] is delayed beyond its rate
9 effective date of January 1, 2021, the Company would be allowed to include [it]
10 in rates once it reaches commercial operation without affecting the rate
11 effective date for all other components of this case," and that this could be
12 accomplished with the use of a tariff rider.[58]
13 **Q. Did PacifiCorp's Reply Testimony result in Staff changing its**
14 **recommendation regarding PacifiCorp having to refile for cost recovery**
15 **if the Pryor Mountain project, including necessary transmission**
16 **infrastructure, is not in service prior to January 1, 2021?**
17 A. Yes. Staff believes there is a reasonable "middle ground," after which the
18 Company should be required to refile for rate recovery in order to address

[55] PAC/2400, Van Engelenhoven/8.

[56] PAC/2000, Wilding/24.

[57] Staff considers this PacifiCorp statement to apply to its Pryor Mountain project as well as to the EV 2020 "New Wind and Transmission Projects," as the question does not specify EV 2020 projects, the answer references a discussion by Mr. Van Engelenhoven (regarding Pryor Mountain), and the following question is "Does Mr. Storm make an *additional* recommendation regarding the Pryor Mountain Wind Project" (emphasis here added by Staff).

[58] PAC/2000, Wilding/24.

potentially changed costs and benefits, or at least confer with parties regarding their support for rate recovery that would begin later than June 30, 2021.

Staff now recommends the Commission require PacifiCorp to confer with the parties to this proceeding regarding cost recovery of the Pryor Mountain new wind project if the project's COD, including that of necessary transmission infrastructure, is after June 30, 2021. If Pryor Mountain is in service on or prior to that date, but after December 31, 2020, Staff recommends allowing a rate effective date following its COD and receipt of the associated attestation.

Q. Did PacifiCorp, in its Reply Testimony, commit to updating the COD for the Pryor Mountain project in its Surrebuttal Testimony?

A. Yes. PacifiCorp stated that the Company "will provide an update on any potential delays in [its] surrebuttal testimony."[59]

Q. Did PacifiCorp's Reply Testimony address the issue of Terminal Value comprising a large portion of net customer benefits?

A. Yes. The Company discussed this issue, with which Staff shared CUB's concern,[60] by first noting that "even without the terminal value benefit, Pryor Mountain is forecasted to provide net customers benefits under both the medium and low natural-gas [price] scenarios."[61]

Q. Did PacifiCorp discuss the components of Pryor Mountain's terminal value?

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[59] PAC/2400, Van Engelenhoven/8.

[60] Staff/800, Storm/49-54.

[61] PAC/2300, Link/68.

A. Yes. The Company stated that the terminal value is comprised of "the value of the transmission assets remaining at the end of the assumed life for the generating resource," the value of the non-transmission assets at the time the generating resource is assumed to retire, and the value of development rights to the site.[62]

Q. How did PacifiCorp value these three components?

A. PacifiCorp performed its terminal valuation using specific assumptions for each of the three components. For the transmission assets, the Company used the remaining net book value of the transmission assets (i.e., after being depreciated for the estimated 30-year depreciable life of the generation assets), by its forecast of inflation over the same 30-year period.

Q. What is the impact of this cumulative inflation on the net book value of the transmission assets?

A. At the 2.28 percent annual estimated rate of inflation used by PacifiCorp in its economic analysis of Pryor Mountain,[63] this essentially doubles (196.7 percent) the remaining net book value of these assets at the estimated retirement date of the WTG equipment 30 years hence. If the transmission assets had a composite depreciable life of about 60 years, PacifiCorp is valuing them in 2050 at essentially their original cost in 2020.

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[62] PAC/2300, Link/69.

[63] See; e.g., cell C3 of spreadsheet "System Value" in the Excel workpaper used by the Company in support of its Opening Testimony regarding the economics of the Pryor Mountain project.

Q. What are the non-transmission assets and how did PacifiCorp value these assets?

A. PacifiCorp mentioned two examples in its Reply Testimony: roads and buildings.[64] The Company first acknowledged that these assets would—at the end of the estimated 30-year depreciable life of the WTG equipment—be fully depreciated, and asserts that they would have a terminal value "because the cost of these assets would not need to be incurred by a successor project."[65] However, PacifiCorp valued these assets by inflating the original cost (i.e., their cost in 2020) over the 30-year period, and then multiplying this amount by "the portion of the original life remaining (50 percent)."[66] As a result of math similar to that described above for the transmission assets, PacifiCorp's 2050 valuation is essentially the cost of these assets in 2020.

Q. What is Staff's take on these valuation methods used by PacifiCorp?

A. Staff first notes that—given Pryor Mountain's location—a positive value for either the transmission or non-transmission assets in 2050 likely depends on the site having economic value as a site for a generation resource in 2050; i.e., the market value of these assets may only be positive if the WTG equipment is replaced by another generation resource. Aside from this question, Staff finds PacifiCorp's valuation methods suspect, as they distill to PacifiCorp asserting that—aside from any value of the site *per se* in 2050—the Company could

[64] PAC/2300, Link/69.
[65] Ibid.
[66] Ibid.

walk away from the Pryor Mountain project in 2050 with the market value of the transmission and non-transmission assets approximately equal to the Company investment in 2020. While this may in fact be the specific future that occurs, it reinforces Staff's view that PacifiCorp should provide sensitivities around its terminal valuation.[67]

Q. How did PacifiCorp estimate the value of the Pryor Mountain site's development rights in 2050?

A. PacifiCorp's Reply Testimony on this indicated it escalated the current value of these development rights by the inflation it forecasts to occur between 2020 and 2050. In other words, the Company approximately doubled its 2020 investment in Pryor Mountain's development rights to estimate the marketable value of these rights in 2050. As above, while this may in fact be the specific future that occurs, this valuation method reinforces Staff's view that PacifiCorp should provide analysis of sensitivities regarding assumptions underlying its terminal valuation.

Q. Did Staff recommend in Opening Testimony that the Commission cap the amount of PacifiCorp's investment in Pryor Mountain at no more than [Begin Confidential] [redacted] [End Confidential]?[68]

A. Yes.

Q. Did PacifiCorp address this in its Reply Testimony?

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[67] See; e.g., Staff/800, Storm/51 – 53.

[68] See; e.g., Staff/800, Storm/54.

A. Yes. PacifiCorp asserted that "it is unlikely that all assumptions will be completely accurate,"[69] but stated that the Company "will not seek more than the amounts included in its initial filing" and that "[a]ny increase [over that amount] would be part of a subsequent rate case, and be subject to a separate prudence review."[70] The Company stated that it "continues to estimate the Pryor Mountain Wind Project costs to be **[Begin Confidential]** [redacted] **[End Confidential]**.[71]

Q. Have the costs of Pryor Mountain increased?

A. Yes. While a reasonable inference might be that costs will increase as a result of PacifiCorp receiving *force majeure* notices from the Company's suppliers and contractors, as noted above, and delayed delivery of WTG equipment, also as noted above,[72] PacifiCorp specifically stated an "incremental cost of approximately $2.8 million"[73] resulting from the substitution of "five Vestas 110-2.2 MW 40 percent safe harbor" WTGs for "five of the 21 Vestas Model 110-2.2 MW safe harbor" WTCs, while also asserting that "[t]he entirety of the Pryor Mountain Project remains eligible for 100 percent PTCs."[74]

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[69] PAC/2000, Wilding/23.
[70] Ibid.
[71] PAC/2400, Van Engelenhoven/6.
[72] PAC/2400, Van Engelenhoven/7.
[73] PAC/2400, Van Engelenhoven/9.
[74] PAC/2400, Van Engelenhoven/8-9.

1 PacifiCorp stated that it "is not including these costs for recovery in this
2 general rate case to the extent that those costs cannot be offset by the
3 reduction of other project costs."[75]

4 **Q. Did PacifiCorp's Reply Testimony result in Staff changing its**
5 **recommendation regarding a cost cap?**

6 A. No. In fact, the reasons Staff recommends a cost cap are now evident.
7 PacifiCorp's costs have increased—for a project that was not required at this
8 time[76] and for a project that places customers at risk—and the risk of cost
9 increases should be borne entirely by the Company, whether such increases
10 are or are not "out of the Company's control."

11 **Q. Did PacifiCorp's Reply Testimony result in Staff changing its**
12 **recommendation regarding an attestation of Pryor Mountain being in**
13 **service?**

14 A. No. Related to this Staff recommendation, Staff notes that Company "does not
15 oppose providing attestations executed by a Vice President of Pacific Power or
16 Rocky Mountain Power attesting that major projects are in service by
17 January 21 [*sic*], 2021."[77] Staff considers the Pryor Mountain project to be "a
18 major project."

19 **Q. Staff discussed its concerns the Pryor Mountain project and PacifiCorp's**
20 **Schedule 272 structure in Opening Testimony in the context of VRET**

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[75] PAC/2400, Van Engelenhoven/9.

[76] Staff/800, Storm/39-43.

[77] PAC/2000, Wilding/19. Staff includes as Exhibit Staff/2002 PacifiCorp's response to Staff Data Request 733, in which the Company states that the intended date here was January 1, 2021.

1 **guidelines. Did PacifiCorp respond to these concerns in its Reply**
2 **Testimony?**
3 A. PacifiCorp stated that Pryor Mountain and similar projects are not VRETs
4 because the energy produced is being supplied to all customers, and the
5 RECs are separated from the energy generated ("unbundled") and sold to
6 customers under Schedule 272.

Q. Is PacifiCorp's explanation of the difference between Schedule 272 and a VRET accurate?

A. No. The distinction that the Company draws between Schedule 272 and the VRET is inaccurate. Under both Schedule 272 and Portland General Electric's (PGE) VRET, the Company procures a new resource that supplies energy to all customers and the voluntary customer or customers receive the environmental attributes. PacifiCorp's argument suggests that the PGE VRET resources are somehow directly serving VRET participants with energy in a manner that is different than any other company PPA or owned resource. This is not the case. While one primary distinction between these two products is that in the PGE VRET the energy and environmental attributes are bundled and under PacifiCorp's Schedule 272 they are not, another is the transparency into the procurement decisions and the allocation of costs, risks, and benefits between cost of service customers and voluntary product customers. This includes VRET processes that control the program's expansion so that incremental costs and risks can be monitored as the program scales up. The

lack of oversight has the potential to harm both cost of service customers and Schedule 272 participants.

Q. Hypothetically, could PacifiCorp undertake to build (or acquire) a new renewable energy generation project every time a Schedule 272-eligible customer sought to obtain RECs?

A. Yes, and—if the timing of such an undertaking was such that the project was not proposed in an IRP, and did not go through the public RFP process—the first time Staff and other Parties would have opportunity to examine PacifiCorp's economic analysis on such a project would be in the context of a general rate case proceeding, as is the case for Pryor Mountain. Staff takes note of CUB's statement included above that, with Pryor Mountain, "other cost-of-service customers are essentially procuring a brown resource with a variable load shape."[78]

Q. What is Staff's concern with respect to Pryor Mountain, Schedule 272, and VRET conditions?

A. Staff's concern is that PacifiCorp may acquire additional resources on the basis of investments Schedule 272 contracts with customers, resulting in additional acquisition of CUB's "brown resource with a variable load shape"[79] and additional risk borne by other cost of service customers. Additionally, the Pryor Mountain project potentially should be operating under the VRET conditions. PacifiCorp's contract with Vitesse functionally operates very

[78] CUB/100, Jenks/53.

[79] Ibid.

similarly to PGE's Green Energy Affinity Rider (GEAR), by which PGE can obtain resource-specific RECs for customers of sufficient size. Both generally allow business customers to achieve their carbon-specific energy goals incremental to the utility's standard resource mix. Both allow the customer to receive the green benefit of the power while cost of service customers pay for the energy produced by the resource. Both can occur outside of least cost/least risk resource planning and may potentially have larger implications for RPS compliance and for the IRP process. Both could potentially create barriers to the competitive retail market. However, only PGE's GEAR is operating under a regulatory framework that ensures that these considerations are addressed in the design, procurement, and implementation of the program. It may be that, based on differing circumstances, Schedule 272 need not comply with the VRET conditions, but Staff has sufficient concern that the issue warrants a more thorough Commission review.

Q. Does Staff seek to "unwind" PacifiCorp's current contract with Vitesse for RECs from Pryor Mountain?

A. No. Given that this contract was already executed under the current Schedule 272 structure and the project is underway, on balance Staff does not believe that Pryor Mountain results in sufficient additional risk to cost of service customers or to the Company to warrant such action. However, PacifiCorp is potentially taking on unnecessary additional risk by operating a VRET-like program outside of the VRET conditions, which are exacerbated by the fact that Pryor Mountain is a utility-owned resource.

Q. Does Staff recommend the Commission prohibit PacifiCorp's future acquisition of utility-owned generation resources involving individually negotiated agreements with new or existing Schedule 272 customers pending the outcome of an investigation?

A. Yes. Given Staff's concerns about the function of Schedule 272 resources and the likely applicability of the VRET guidelines, Staff recommends the Commission stay PacifiCorp's ability to own resources that supply RECs to Schedule 272 customers pending the outcome of an investigation into PacifiCorp's Schedule 272 and application of the VRET conditions. Given the shift in Staff's position on this issue and the relatively lower risk to cost of service customers associated with non-utility owned resources, Staff does not seek a similar stay for non-utility owned resource acquisitions that would supply RECs to Schedule 272 customers pending a Commission investigation into whether Schedule 272 meets the VRET guidelines.

Q. What does Staff recommend?

A. Staff recommends the Commission:

1. Find PacifiCorp's decision to invest in the Pryor Mountain new wind project to be prudent, based on the assumptions and analysis presented by the Company in this proceeding.
2. Cap PacifiCorp's investment in Pryor Mountain for purposes of ratemaking in this proceeding at no more than **[Begin Confidential]** [redacted] **[End Confidential]**.

3. Require PacifiCorp to provide a signed declaration from a Vice President of Pacific Power or Rocky Mountain Power attesting to the Pryor Mountain new wind project having been placed in service and in commercial operation prior to its inclusion in rates.
4. Require PacifiCorp to confer with parties to this proceeding regarding cost recovery of the Pryor Mountain new wind project if the project's COD, including that of necessary transmission infrastructure, is after June 30, 2021. If Pryor Mountain is in service on prior to that date, but after December 31, 2020, Staff recommends allowing a rate effective date following its COD and receipt of the associated attestation.

Regarding Schedule 272:

5. Open an investigation into Schedule 272 and the applicability of VRET conditions.
6. Suspend PacifiCorp's entering into new Schedule 272 individually negotiated agreements that include supplying RECs from utility-owned resources pending the outcome of such an investigation.

1 **ISSUE 4, POST-RETIREMENT EMPLOYEE BENEFIT PLANS OTHER THAN**
2 **PENSION**

3 **Q. Did Staff provide a recommendation regarding the total of net book**
4 **values of the equipment replaced as part of the wind repowering**
5 **projects in UE 352?[80]**

6 A. Yes. Staff recommended the Commission:
7 Require PacifiCorp to reduce the annual cost of the Company's Other Post-
8 retirement Employee Benefit (OPEB) plan by $1.39 million.

9 **Q. Did Intervenors discuss the Pryor Mountain new wind project in Opening**
10 **Testimony?**

11 A. No.

12 **Q. Did PacifiCorp discuss this Staff issue in the Company's Reply**
13 **Testimony?**

14 A. Yes. PacifiCorp asserted the approach used in Staff's analysis was "flawed as
15 it is both unreasonable to rely on assumptions from others' plans and…is
16 unacceptable under Accounting Standards Codification Topic 715-60, Defined
17 Benefit Plants-Other Postretirement (ASC 715-60)."[81]

18 **Q. Did PacifiCorp provide further explanation?**

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[80] UE 352 was PacifiCorp's 2019 Renewable Adjustment Clause (RAC) proceeding

[81] PAC/2100, Kobliha/18.

1 A. Yes. The summary principle Staff points to here is, as stated by PacifiCorp,
2 "ASC 715-60 requires the use of explicit assumptions individually representing
3 the best estimate of future activity associated with the plan's obligations."[82]
4 **Q. Did Staff base its recommendation in Opening Testimony on its analysis**
5 **of the cash flows in each of the individual OPEB plans it used to derive**
6 **average EROA and discount rate values?**
7 A. No, and as a result, Staff withdraws its recommended adjustments to
8 PacifiCorp's OPEB expense in this proceeding.
9 **Q. Does this conclude your testimony?**
10 A. Yes.

[82] PAC/2100, Kobliha/19.

CASE: UE 374
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2001

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

UE 352 / PacifiCorp
February 13, 2019
AWEC Request 009

AWEC Data Request 009

Please identify the gross plant of property, by FERC account, that will be retired pursuant to PacifiCorp's repowering program for each of the following wind facilities: Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, Glenrock I, Goodnoe Hills, High Plains, McFadden Ridge, Marengo I and Marengo II.

Response to AWEC Data Request 009

The gross plant of property identified below is not being retired, but rather individual components are being replaced.

Please refer to the table provided below:

Facility	Original value being Replaced	Estimated Accumulative Reserve at Repower Date	Estimated Net Book Replaced at Repower Date	Estimated Replacement Cost
Glenrock I	$116,952,332	$ (44,899,854)	$ 72,052,477	$ 1,479,000
Seven Mile Hill I	$131,382,281	$ (46,539,318)	$ 84,842,963	$ 1,683,000
Seven Mile Hill II	$ 27,105,247	$ (9,586,572)	$ 17,518,675	$ 331,500
High Plains	$145,932,412	$ (51,308,936)	$ 94,623,476	$ 1,683,000
McFadden Ridge	$ 37,402,088	$ (13,257,969)	$ 24,144,119	$ 484,500
Leaning Juniper	$107,016,060	$ (45,289,711)	$ 61,726,349	$ 2,010,000
Marengo I	$167,445,463	$ (71,696,920)	$ 95,748,543	$ 2,340,000
Marengo II	$ 86,385,845	$ (34,956,430)	$ 51,429,415	$ 1,170,000
Goodnoe Hills	$135,844,803	$ (50,836,563)	$ 85,008,240	$ 1,410,000

These assets will be credited from FERC Account 101 (Electric Plant in Service) and debited to FERC Account 108.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

CASE: UE 374
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2002

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

UE 374/PacifiCorp
July 8, 2020
OPUC Data Request 733

OPUC Data Request 733

Date in PAC/2000
Please confirm or deny the accuracy of the January 21, 2021 date at PAC/2000, Wilding/17 Line 17. If the stated date is accurate, please explain the use of this date (as opposed to January 1, 2021).

Response to OPUC Data Request 733

PacifiCorp understands OPUC Data Request 733 is referring to PAC/2000, Wilding/19 Line 17. With this understanding, the use of January 21, 2021 was typographical error, the date should be listed as January 1, 2021.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

CASE: UE 374
WITNESSES: NADINE HANHAN,
YASSIR RASHID,
AND MATTHEW MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2100

Rebuttal Testimony

July 24, 2020

Q. Please each state your name and occupation.

A. My name is Nadine Hanhan. I am a Senior Utility Analyst employed in the Energy Resources and Planning (ERP) Division of the Public Utility Commission of Oregon (OPUC).

A. My name is Yassir Rashid. I am an Electrical Engineer and Senior Utility Analyst employed in OPUC's Safety, Reliability, and Security Division.

A. My name is Matt Muldoon. I am the Economic Analysis Program Manager within the Energy Rates, Finance, and Audit (ERFA) Division of the OPUC.

Q. What is your common business address?

A. 201 High Street SE, Suite 100, Salem, OR 97301.

Q. Please describe your educational background and work experience.

A. Our educational background and work experience are set forth in our respective Witness Qualification Statements, provided as Exhibits Staff/1401, Staff/1402, and Staff/201.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to AWEC's and PacifiCorp's testimony pertaining to transmission, prepare certain adjustments to revenue requirement based on evidence Staff has collected, describe the profound shortcomings of the data that Staff had to work with, and provide recommendations for cost recovery moving forward.

Q. What is your summary recommendation?

A. All projects considered, Staff recommends a total disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for PacifiCorp's transmission investments, which is approximately **[BEGIN CONFIDENTIAL]**

[redacted] **[END CONFIDENTIAL]** Oregon-allocated investments. This number includes both the projects in Mr. Vail's testimony and the projects in the confidential Pro Forma work paper Exhibit PAC/1309, McCoy/16.

Q. Did you prepare any exhibits for this testimony?

A. Yes. Please see we prepared Staff Exhibits 2101 through 2108.

Q. How is your testimony and analysis organized?

A. Our testimony is organized as follows:

Issue 1: Response to Other Parties' Testimony 3
Issue 2: Discovery Process 7
Issue 3: Project-by-Project Assessment 15
Issue 4: Unverifiable Projects 42
Issue 5: Recommendations 53

ISSUE 1 – RESPONSE TO OTHER PARTIES' TESTIMONY

Q. What other party submitted testimony in this case pertaining to transmission projects?

A. Other than Mr. Richard Vail on behalf of PacifiCorp, only Mr. Bradley Mullins of AWEC discussed transmission projects in this case.

Q. Could you summarize Mr. Mullins' testimony pertaining to transmission?

A. Yes. Mr. Mullins only discussed the transmission projects related to Energy Vision 2020. AWEC recommended that the Commission put customer protections in place for EV 2020 wind and related transmission projects as follows:

1) The Commission should impose a hard cap on capital and operations and maintenance (O&M) costs at the level assumed in the request for proposals (RFP) bids.
2) The Commission should impose a hard cap on costs for the D.2 segment of the Energy Gateway transmission project based on projections used in the RFP.
3) A guarantee of full production tax credits (PTC) and energy benefits regardless of the in-service date and regardless of delays resulting from contractors.
4) A minimum capacity factor for each resource at the level modeled in the RFP bids.

Q. Do you have any concerns with this position?

A. No. At its core, Mr. Mullins' position is consistent with Staff's Opening Testimony. Staff also recommended cost caps and agrees that PTC benefits should be secured to customers. Staff testimony Staff/800, Storm/37 recommended that new wind projects be found prudent under the condition that projected net benefits be found in the Transition Adjustment (TAM) proceeding and that the new wind projects qualify for 100 percent of production tax credits. In addition, Staff testimony Staff/1300, Gibbens/34 also explains that as part of the 2019 TAM stipulation, parties already agreed to hold the wind capacity factors at the P50 forecasts used to justify the investment.

Q. Could you summarize Mr. Richard Vail's testimony pertaining to transmission?

A. Yes. Mr. Vail provided a project-by-project response to Staff's testimony. Mr. Vail also addressed Staff's recommendations pertaining to officer attestations, cost caps, unrecovered balances, and how to treat cost recovery in the event that an Energy Vision 2020 project is not in service. In general, Mr. Vail proposed a modification regarding attestation (allowing a Vice President to sign an attestation in addition to an officer), stated that cost caps are not generally necessary or that Staff did not defend them appropriately, and reiterated the reliability purposes of the transmission projects. We provide further detail about Mr. Vail's responses under Issue 3 when we discuss the projects individually.

Q. How did Mr. Vail respond to Staff's concerns regarding cost overruns?

A. Mr. Vail indicated that PacifiCorp is not requesting a true-up to actual costs or recovery of any overages to anticipated costs in this rate case, meaning that

costs would be capped for purposes of this case at the amounts requested in the Company's initial filing. He indicated that any such increase to costs would be subject to a future prudence review in a subsequent rate case, and subsequently that Staff's concerns are not relevant.[1]

Q. Do you agree with this?

A. No. Staff identified significant cost overruns for a number of projects that are not yet in service. Some of these costs were indeed included in the estimates provided in Mr. Rick Vail's testimony. While additional overages of anticipated costs, relative to what is included in the Company's initial filing, might not be included in the rate case, this does not mean that cost overages incurred up to the point the rate case was prepared were not incorporated in the Company's cost estimates. Staff addresses cost overruns later on in testimony.

Q. Could you respond to Mr. Vail's statements about officer attestations of project in-service dates?

A. Yes. Mr. Vail responded to Staff's recommendation regarding requiring officer attestations that major projects are in-service by December 31, 2020. Mr. Vail agreed that an attestation is appropriate, but he also proposed to allow that the attestation be signed by either a Vice President or Officer and that threshold for major projects be greater than $5 million on an Oregon-allocated basis.

Q. Are you comfortable with this proposal?

A. For the attestations, yes. This is consistent with Staff's recommendation in Staff/800, Storm/3. Staff would be comfortable with a proposal that an

[1] PAC/2800, Vail/4.

1 attestation be signed by an officer or a Vice President of Pacific Power or
2 Rocky Mountain Power. As for the proposal that these attestations be limited
3 to projects over $5 million, Staff can accept this for the projects for which costs
4 in this case have been verified. This issue is discussed further below.

ISSUE 2 – DISCOVERY PROCESS

Q. Could you please summarize your experience with discovery in this docket?

A. Yes. Please see the following table, which summarizes the timing delays indicating when Staff has received late discovery. Staff has run into a number of pitfalls throughout this process that has made it challenging to produce recommendations. Some of those challenges have been in the form of significant delays from the Company, vague or inconsistent detail depending on the projects we asked about, failure to provide information for key discovery requests, and unresponsiveness. In addition to issuing follow-up data requests, Staff also engaged in informal phone calls to better understand information, conferring on discovery responses, and generally trying to work with the Company in getting the information necessary to analyze these projects and make recommendations to the Commission. Ultimately, this did not result in useful information.

1 *Table 1 – Discovery Delays*

Data Requests	Date Requested	Due Date	Received[2]	Days late/Quality of response	Total #[3]
143-175	3/19/2020	4/2/2020	4/10/20, 4/16/20 4/20/20, 7/9/20 (Suppl.)	7,14,18	33
225-228	4/3/2020	4/17/2020	4/17/2020	0, unanswered	4
444-462 (C)	5/5/2020	5/19/2020	5/20/2020	1	19
463-504	5/5/2020	5/19/2020	5/21/2020	2	42
525-533	5/14/2020	5/28/2020	5/29/2020	1, unanswered	9
Staff Internal Deadline	-	5/4/2020	-	-	-
Staff Opening Testimony	-	6/4/2020	-	-	-
Settlement	-	6/18/2020	-	-	-
Settlement	-	6/19/2020	-	-	-
Company Reply Testimony	-	6/25/2020	-	-	-
Q&A with Company	-	6/30/2020	-	-	-
734-749	7/2/2020	7/9/2020	7/9/20 – 7/17/20	0,1,2,3,4,8, unanswered	16
Second Q&A	-	7/15/2020	-	-	-
Staff Internal Deadline	-	7/17/2020	-	-	-
Staff Rebuttal Testimony	-	7/24/2020	-	-	-

2 **Q. Could you please explain the table above?**

3 A. Yes. As the table demonstrates, **no batch of data requests was fully**

4 **received on time**. "Unanswered" requests are those for which Staff is *still*

5 waiting for key information. For example Staff has still not received an itemized

6 breakdown of Pro Forma projects (DR 228), one-line diagrams of projects

[2] Indicates when responses were uploaded to Huddle, or in the case of highly confidential contracts, were received by Staff.
[3] This number does not include subparts.

under one million (DR 529), quality one line diagrams of Pro Forma projects (DR 531), quality one-line diagrams of the projects in Mr. Vail's testimony (DR 530), as well as all project contracts (DRs 745 and 746).[4] While the Company did provide this type of information for some projects, the information presented to Staff was inconsistent in kind and quality throughout.

Q. Did Mr. Vail address discovery delays in his testimony?

A. Yes. Mr. Vail acknowledged that there were delays.[5] Mr. Vail in his testimony also complained that Staff did not provide any prudence recommendations or discuss reliability benefits for the projects in the case, and that an opportunity for all parties to build a thorough record on the issue would now have to be done in only two rounds of testimony.[6]

Staff reiterates its statements from Opening Testimony that we did not receive discovery in a timely fashion, making it impossible to make final recommendations in its Opening Testimony. Upon receiving voluminous discovery mid-April, Staff only had two weeks to analyze the voluminous responses, as well as simultaneously submit follow-up requests and write Opening Testimony by the internal deadline of May 4. Given the delayed responses, there was not sufficient information of acceptable quality to be able to provide any reasonable recommendations with confidence.

[4] See Staff Exhibit 2101 for a list of Staff Data Requests and 2102 for a list of confidential requests.
[5] See PAC/2800, Vail/2.
[6] See PAC/2800, throughout.

Q. Earlier you stated that the information PacifiCorp sent you was inconsistent in kind and quality. Could you explain what you mean by this?

A. Yes. The quality of information provided to Staff varied greatly. For some projects, particularly the projects in Mr. Vail's testimony, Staff ultimately received enough information from testimony and discovery to be able to determine prudence and used and usefulness for this round of testimony. We discuss these projects later on in this testimony.

However, for other projects, particularly the ones in the Pro Forma confidential transmission spreadsheet,[7] Staff still does not have sufficient information to make conclusive recommendations, despite multiple attempts at discovery and collaborative technical workshops with the Company. For example, twice in the course of this case, Staff requested one-line diagrams of the projects in Rick Vail's testimony. Both times, the Company referred Staff to the lackluster one-line diagrams already provided in Mr. Vail's exhibits. Detailed one-line diagrams are a very basic component of transmission projects that would help to understand the fundamentals of a particular line's function. We asked for one-line diagrams of all projects in Mr. Vail's testimony, the Pro Forma spreadsheet in Ms. McCoy's testimony, and all projects under $1 million. On a technical workshop with the Company, Staff explained the type of maps and one-line diagram information that was sought to the Company. This information was still not consistently provided. While we received some

[7] Exhibit PAC/1309, McCoy/16.

1 detailed one-line diagrams, the quality of information throughout was
2 inconsistent and in some cases, not helpful in Staff's analysis.
3 Confidential Exhibit 2103 shows a variety of the types of one-line
4 diagrams Staff received. Compare these to the one-line diagrams provided in
5 Mr. Vail's Opening Testimony. A reasonable person doing a quick review of the
6 one-line diagrams provided by Mr. Vail can easily see that the level of detail is
7 inconsistent. The missing detail is material to Staff's analysis of these issues.
8 **Q. Did you run into any other inconsistency issues in your review?**
9 A. Yes. Cost detail was also inconsistent.
10 **Q. Could you explain what issues you ran into regarding estimating**
11 **costs?**
12 A. Yes. The costs provided by PacifiCorp in the Pro Forma spreadsheet[8] had
13 very little definition of what those costs represented, how they were developed,
14 or any further detail. Ultimately, some substantial cost line items were
15 unverifiable. See the top most projects in the confidential Pro Forma
16 Spreadsheet.[9]
17 **Q. Were you able to verify costs, and by extension, prudence?**
18 A. Not in every case, because cost detail was inconsistent. Staff asked for similar
19 information (one line diagrams, change orders, itemized details, contracts, etc.)
20 for three tiers of projects: the projects in Mr. Vail's testimony, the projects in the
21 Pro Forma spreadsheet, and projects under $1 million.[10] Staff also asked for

[8] Exhibit PAC/1309, McCoy/16.
[9] Exhibit PAC/1309, McCoy/16.
[10] See Staff Exhibit 2101.

1 narrative descriptions, and while the Company provided these, they were high
2 level.[11] To this day, the Company has not sent Staff all the information
3 requested in Data Request 529.

4 After over 300 data requests, some of which were asked multiple times
5 and in different forms, (for example, Staff asked for internal approval documents,
6 change orders, and initial budgets), and two phone calls, there is still additional
7 information that is needed to verify not only prudence but used and usefulness.
8 We elaborate more on this issue further in our testimony.

9 **Q. In what other ways did Staff attempt to verify cost, and by extension,**
10 **whether costs were prudently incurred?**

11 A. Staff asked about how the Company approached materials acquisition.
12 Specifically, we asked whether the Company ratcheted down costs when the
13 price of various metals decreased. PacifiCorp's initial response to Staff was
14 unsatisfactory. See Staff Exhibit 2101 (DR 151) for how the Company initially
15 answered this question. Staff did not get clear answers to the Company's
16 approach to materials acquisition until the phone call on June 30. However,
17 overall, Staff's general sense is that the Company did a good job at keeping
18 the costs of the bigger (i.e., Energy Gateway) projects under or at budget. The
19 smaller projects, conversely, were generally very difficult to verify. We go into
20 more detail about this below.

[11] See the first four pages of Confidential Exhibit 2103.

Staff also asked about hydrology, geology, and elevation changes, and how the Company treated these. See Staff Exhibit 2101 (DR 152) for the Company's unsatisfactory answer.

Q. Could you summarize what information you requested that was necessary for Staff to feel confident verifying costs, prudence, and used and usefulness?

A. Yes. One of the main shortcomings of the information provided to Staff is that few of the transmission project costs were initially supported with detail, and when Staff asked for that additional detail, it was inconsistent in form and quality, making it difficult to make comparisons across projects. It was therefore impossible to verify and conclude that these costs were appropriate or whether the projects were appropriately allocated as having system benefits. Below is some information that would have been more helpful to Staff:

1) The information requested in DR 529 c., which asked for all internal approval documents of these projects. This information is still outstanding. This information could have helped Staff determine the prudence of cost overruns, if any. The Company only referred Staff to an earlier data response, which only provided a project list. See Staff Exhibit 2101 for how the Company answered this question.
2) One-line diagrams of a sufficient level of detail beyond what was provided by Mr. Vail, which was described by Staff to the Company on the July 15 phone technical workshop.
3) A sufficient level of detail regarding how the Company determined what constituted a "system benefit" project and a "local benefit" project. See

Staff Exhibit 2101 for the Company's unsatisfactory answer to this question. We provide more detail about this under Issue 4.

4) Full project contracts in a timely fashion.

5) Any additional change orders or cost overrun information for all transmission projects in this case. Staff asked for all change orders in early March, but the Company only initially provided change orders for the projects discussed in Mr. Vail's testimony, which does not cover all projects. It was not until Staff re-asked the question in a different way that Staff obtained additional cost information for other projects.

Q. How many Data Requests did you end up making to try to verify costs?

A. Staff asked a total of 321 data requests (including subparts) in an attempt to verify prudently incurred costs and used and usefulness for transmission projects.[12] As we explained, some of this information was requested multiple times, and in various ways. Staff only received bits and pieces of this information throughout the case, with varying amounts of quality and detail. Often, Staff's requests were met with a request for extensions or special handling requirements.

Q. What were the overall impacts of these discovery challenges?

A. Discovery delays deterred Staff's ability to provide concrete recommendations in Opening Testimony. More importantly, the absence of material detail provided throughout this case also impeded Staff's ability to make concrete findings of prudence.

[12] See Staff Exhibit 2101 of all non-confidential discovery requested in this docket. Exhibit 2102 contains confidential requests.

ISSUE 3 – VERIFIABLE PROJECTS

Q. Please summarize this portion of your testimony.

A. In this portion of testimony, Staff will provide cost recovery recommendations for the following projects that had verifiable costs and purposes:

- Aeolus to Bridger/Anticline (A2B)
- Q707 TB Flats 1
- Q712 Cedar Springs Wind 1
- Wallula to McNary (W2M)
- Snow Goose Substation
- Vantage to Pomona Heights
- Sigurd to Red Butte (S2RB)
- Goshen-Sugarmill-Rigby
- NE Portland Upgrade
- SW Wyoming Silver Creek
- Threemile Canyon Farm
- Q0542 Pryor Mountain[13]
- **[BEGIN CONFIDENTIAL]** [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[13] Exhibit PAC/1302, McCoy/223.

- [redacted] **[END CONFIDENTIAL]**

Q. What approach did you take to verify the costs?

A. First, Staff reviewed Rick Vail's testimony and the data responses and attachments provided by the Company. If a project was under 200 kV, Staff took greater scrutiny in examining whether a project appeared to deliver system, or "primary grid" benefits. In general, higher-voltage lines are more likely to be associated with backbone transmission projects that provide energy across all the states that PacifiCorp serves. Lower voltage projects, such as 69 kV or 115 kV lines, are more likely to support local load. Staff also reviewed change orders to determine whether there were cost overruns for these projects, and what caused those cost overruns.

If a project was over 200 kV, Staff tried to identify whether cost overruns occurred and assessed the reasonableness of those cost overruns. Staff also tried to verify, depending on the information provided, whether the projects provided a system benefit.

Q. What projects from Mr. Vail's testimony do you believe the Company provided sufficient information to determine that costs were prudently incurred?

A. From Mr. Vail's testimony, these projects include

- Aeolus to Bridger/Anticline ($679.1 million, $176.7 Oregon allocated)
- Q707 TB Flats 1 ($30.6 million, $8.0 million Oregon-allocated)
- Q712 Cedar Springs Wind 1 ($61.7 million, $16.1 million Oregon-allocated)

- Snow Goose Substation ($42.5 million, $11.1 million Oregon allocated)
- Sigurd to Red Butte ($354 million, $92.1 million Oregon allocated)
- NE Portland Upgrade ($20.6 million, $5.4 million Oregon allocated)

Q. Why do you believe these projects were prudent?

A. Based on detailed project review of testimony, requested change orders,[14] original budgets,[15] and a phone call with the Company on June 30 that explained its acquisition approach, Staff is comfortable that costs for these projects were prudently incurred. Staff found that the Company is requesting cost recovery **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** thus, Staff did not identify cost overruns. Further, upon Staff's review of project function, Staff agrees that these provide reliability benefits for Oregon customers.

In addition, certain projects, such as the Sigurd-to-Red Butte project, came in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[16]

Q. Did Mr. Vail address Aeolus-to-Bridger in his testimony?

A. Yes. He restated the reliability benefits of the line[17] and restated that the economics of the line is improved due to associated wind PTCs.[18] The overall statements he made were in large part a restatement of his Opening

[14] See Staff Confidential Exhibits 1405, 2105, and 2107.
[15] See Staff Confidential Exhibit 2106.
[16] See Staff Confidential Exhibit 1405.
[17] PAC/2800, Vail/7-8.
[18] PAC/2800, Vail/11.

1 Testimony. He also proposed to modify or remove some of Staff's
2 recommendations.
3 **Q. What modifications did Mr. Vail propose?**
4 A. As mentioned earlier, Mr. Vail proposed a modification regarding attestation—
5 allowing a Vice President to sign an attestation in addition to an officer. He
6 also stated that cost caps are not generally necessary and challenged the idea
7 that Aeolus-to-Bridger should be disallowed in the event any Energy Vision
8 2020 wind projects are not in-service.
9 **Q. Do you agree with Mr. Vail's assessments?**
10 A. In part. Mr. Vail did clarify that the confidential, lower costs Staff had originally
11 identified[19] did not include the full anticipated costs. After additional discovery
12 and review, Staff was able to confirm that the estimated costs for this project
13 are consistent with what was estimated in the 2017 IRP and that there appears
14 to be no cost overruns associated with this project. After the June 30 phone
15 call, Staff was reassured that the Company had prudently incurred these costs
16 through its materials acquisition practices. Staff can also agree that the project
17 will provide backbone system reliability benefits as well as enable additional
18 wind generation. However, Staff still believes customer protections for this
19 project are appropriate.
20 **Q. What sort of customer protections are you referring to?**
21 A. We are referring to the recommendations provided in Opening Testimony,
22 which are repeated below:

[19] See Staff Confidential Exhibit 1405.

- The Company must file an officer attestation that all requested wind and transmission buildout is in-service by the time rates go into effect. Components of the project not in-service by the target date of December 31, 2020, should be removed from revenue requirement.
- There should be a cost cap for rate recovery.
- Any unrecovered balances should be subject to a future ratemaking proceeding. Staff reserves the right to address associated prudence issues in a future general rate case.
- Require PacifiCorp to refile for cost recovery of A2B if any EV 2020 new wind and transmission projects' Commercial Operation Date (COD) is after December 31, 2020. PacifiCorp must re-file for cost recovery for any projects that are not used and useful.

Q. Do you still maintain these customer protections are needed?

A. Yes. Staff still maintains the first three are necessary. As mentioned earlier in this testimony, Staff can agree to modify the first recommendation to include a Vice President of Rocky Mountain Power or Pacific Power. Though Mr. Vail insists that cost caps are not necessary because the Company is not requesting overruns in this project, Staff still believes there should be a cap for ratemaking purposes in this case in the event overruns do occur prior to the rate-effective date. The cost cap should be at the requested amount, $679.1 million. This recommendation is consistent with Mr. Mullins' testimony and is not unreasonable. Likewise, Staff finds the PacifiCorp maintains the right to

request rate recovery for any additional costs in a future ratemaking proceeding.

As for the final recommendation, upon further consideration, Staff concludes that if any energy flows across A2B by December 31, it could be deemed as used and useful by the Commission. However, Staff still maintains that cost recovery should not occur in the event it is not energized. Therefore, Staff modifies its original recommendation to the following:

- Require PacifiCorp to refile for cost recovery of A2B if its Commercial Operation Date (COD) is after December 31, 2020. PacifiCorp must re-file for cost recovery for any projects that are not used and useful.

Q. What about the other Energy Vision 2020 projects, Q707 TB Flats 1 Q712 Cedar Springs Wind 1? Did Mr. Vail's testimony discuss these?

A. Yes. Similar to Aeolus-to-Bridger, Mr. Vail restated the projects' functions, namely that both of those projects meet PacifiCorp's obligations under its Open Access Transmission Tariff (OATT) and provide for the interconnection of new renewable generation.[20] Mr. Vail also provided modifications to Staff's recommendations. Like with Aeolus-to-Bridger, he proposed allowing a Vice President to sign an attestation in addition to an officer. He also stated that cost caps are not generally necessary and challenged the idea that these projects should be disallowed in the event that A2B or the Energy Vision 2020 wind projects are not in-service.[21]

Q. Do you agree with Mr. Vail's modifications?

[20] PAC/2800, Vail/16.
[21] PAC/2800, Vail/13.

A. In part. After additional discovery and review, Staff was able to confirm that the estimated costs for these projects did not appear to incur any cost overruns. After the June 30 phone call, Staff was reassured that the Company had prudently incurred these costs through its materials acquisition practices. Staff can also agree that the projects will provide system benefits by enabling additional wind generation. However, Staff still believes customer protections for this project are appropriate, and that the projects should not receive cost recovery if they are not delivering power to the grid.

Q. Could you state your modified recommendations?

A. Yes. Staff recommends the following:

- The Company must file an attestation from an officer or a Vice President of either Pacific Power or Rocky Mountain Power that all requested wind and transmission buildout is in-service by the time rates go into effect. Components of the project not in-service by the target date of December 31, 2020, should be removed from revenue requirement.
- There should be a cost cap for rate recovery at $30.6 million and $61.7 million for Q707 TB Flats 1 and Q712 Cedar Springs Wind 1, respectively.
- Any unrecovered balances should be subject to a future ratemaking proceeding.
- Require PacifiCorp to refile for cost recovery of EV 2020 transmission projects' Commercial Operation Date (COD) is after December 31,

2020. PacifiCorp must re-file for cost recovery for any projects that are not used and useful.

Q. Did Mr. Vail address the Snow Goose substation project?

A. Mr. Vail indicated that because Staff had not yet identified a concern or recommendation, he could not respond to Staff's testimony.

Q. Do you have any recommendations about the Snow Goose substation project?

A. Yes. Staff discovered that the cost of this project is not $42.8 million as initially indicated by PAC/1000, Vail/11, but rather $42.5 million. The Company confirmed this via discovery.[22] Upon further discovery and review, Staff agrees that this project delivers system benefits. This project also did not incur cost overruns, but actually came in significantly under budget by over **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as compared to originally estimated costs.[23] After the phone call on June 30 and hearing about the Company's general materials acquisition practices, Staff believes the $42.5 million was prudently incurred and that the project will be used and useful to Oregon customers.

Q. Did Mr. Vail address the Sigurd-to-Red Butte transmission project?

A. Mr. Vail indicated that because Staff had not yet identified a concern or recommendation, he could not respond to Staff's testimony. He also reiterated

[22] See Staff Exhibit 2101. (Staff DR 748).
[23] Compare the $42.5 million to change orders in Staff confidential exhibit 1405.

the project's benefits as "an important piece in strengthening the Western Interconnection transmission infrastructure."[24]

Q. What is your recommendation for this project?

A. Upon further discovery and review, Staff agrees that this project delivers system benefits. This project also did not incur cost overruns, but actually came in well under budget by over **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[25] After the phone call on June 30 and hearing about the Company's general materials acquisition practices, Staff believes costs were prudently incurred and that the project will be used and useful to Oregon customers.

In addition, to address the Commission's concerns as explained in our Opening Testimony,[26] Staff examined the 2013 IRP load forecasts and compared them to actual SW Utah load. While the general load forecasts provided by the Company did overshoot actual load, on average, it did not appear to be unreasonably over-projecting average hourly loads. Staff can also agree with the Company that this project helps to strengthen Western Interconnection transmission infrastructure, and as Staff indicated in its Opening Testimony, this project was acknowledged by the Oregon Commission in the 2013 IRP.[27] Staff therefore believes that the $354.6 million for this project was prudently incurred and is used and useful.

Q. Did Mr. Vail discuss the NE Portland Upgrade project?

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[24] PAC/2800, Vail/26.
[25] Compare the $354 million to change orders in Staff confidential exhibit 1405.
[26] Order No. 14-252.
[27] Order No. 14-252.

A. Yes. Mr. Vail clarified two of Staff's concerns about this project: the actual in-service date and costs. The Company confirmed that the in-service date of May 2019 was accurate and also corrected another error in costs. Staff had been referring to PAC/1000, Vail/11, which mistakenly included the total cost of the project in the table summary. This led to adding an extra $20.6 million in table estimates. However, Mr. Vail's testimony clarified that this was an error and that the actual cost requested for this project was the number stated later on in his testimony, $20.6 million.[28] Staff appreciates these clarifications.

Q. What is your recommendation for the NE Portland project?

A. Upon further discovery and review, Staff agrees that this project delivers system benefits to Oregon customers. This project also did not incur cost overruns, but appears to have come in slightly under budget by **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[29] Staff believes the $20.6 million was prudently incurred and that the project will be used and useful to Oregon customers.

Q. What other projects do you believe the Company provided sufficient information for in order to receive cost recovery?

A. These were projects not identified in Mr. Vail's testimony and include items stated in Ms. Shelley McCoy's Confidential Pro Forma workpaper 8.5.[30] Staff reviewed projects for which it received information to understand the frequency of cost overruns and whether projects contribute to system benefits. Below are

[28] PAC/2800, Vail/27.
[29] Compare the $20.6 million to change orders in Staff confidential exhibit 1405.
[30] Exhibit PAC/1309, McCoy/16.

the projects for which Staff could reasonably agree with the Company. These projects total **[BEGIN CONFIDENTIAL]** [redacted][31]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

  [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted] **[END CONFIDENTIAL]**

Q. Why do you believe cost recovery is warranted with these projects?

A. Based on Staff's project review through discovery, requested change orders, and other documents, Staff is comfortable that these projects serve system benefits (and will therefore be used and useful) and also that there were no identifiable cost overruns. All of these projects are higher-voltage transmission projects and appear to deliver system benefits to Oregon customers. A summary of these projects, as well as their change orders and other documentation has been attached as Confidential Staff Exhibits 2103 and 2107.

Q. Are there any verifiable projects from the Company's testimony that you believe should receive disallowances?

[31] All projects retrieved from Confidential Spreadsheet 8.5 Pro Forma Plant Additions.

A. Yes. These include the following, for a total of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in total costs from the projects in Mr. Rick Vail's testimony, and a total of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in Pro Forma costs from Ms. Shelley McCoy's workpaper. This totals **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in total disallowances for verifiable projects. Staff explains its reasons for disallowance for each project below.

<u>Project disallowances from Mr. Vail's testimony (total system):</u>

- Wallula to McNary (W2M): **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**
- Vantage to Pomona Heights **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**
- Goshen-Sugarmill-Rigby (total project disallowance of $21.5 million)
- SW Wyoming Silver Creek (total project disallowance of $41.9 million)
- Threemile Canyon Farm **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

<u>Verifiable project disallowances from the Pro Forma workpaper (total system):</u>

- Q0542 Pryor Mountain **[BEGIN CONFIDENTIAL]** [redacted]
- [redacted]
- [redacted]
- [redacted] **[END CONFIDENTIAL]**

Q. What are your recommendations for the Wallula-to-McNary project?

A. Based on Staff's project review through testimony, discovery, requested change orders, original budgets, one-line diagrams, and other documents, Staff is comfortable that these projects serve system benefits (and will therefore be used and useful). However, Staff believes that this project incurred cost overruns, and that those should be disallowed.

Q. Did Mr. Vail address cost overruns for the Wallula-to-McNary project?

A. No. Mr. Vail indicated that because Staff has not yet identified a concern or recommendation, he could not respond.

Q. Why do you think the Wallula to McNary project should receive a disallowance?

A. According to documents obtained by Staff, this project has cost overruns of roughly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** that should be disallowed. The project was initially budgeted at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for a maximum project cost estimate of about **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[32] Requested cost recovery in this case is $42.6 million.[33] The reasons given for the cost overrun are several.

[BEGIN CONFIDENTIAL] [redacted]

[32] See Confidential Staff Exhibit Staff/1405.
[33] PAC/1000, Vail/11.

[redacted]. **[END CONFIDENTIAL]**[34] Overall, these project delays resulted in an overrun of **[BEGIN CONFIDENTIAL]**[redacted]**END CONFIDENTIAL]** compared to original cost projections, including an allowance for contingencies.

Q. Should the Company have known about these?

A. Yes, we believe so. The Company should have been aware of **[BEGIN CONFIDENTIAL]**[redacted] **[END CONFIDENTIAL]**[35] This is basic knowledge that the Company should have known and anticipated as a possibility for resource acquisition, especially as PacifiCorp has the resources to hire legal counsel to advise on such proceedings. Ratepayers should not be held responsible for these kind of errors that cause cost overruns, particularly to this magnitude, nor should they be held responsible for costs that are incurred due to **[BEGIN**

[34] See Confidential Staff Exhibit Staff/1405.
[35] See Confidential Staff Exhibit Staff/2102.

1 **CONFIDENTIAL]** [redacted]

2 [redacted]

3 [redacted]. **[END CONFIDENTIAL]**

4 **Q. What are your recommendations for the Vantage-to-Pomona Heights**

5 **project?**

6 A. Based on Staff's project review through testimony, discovery, requested

7 change orders, original budgets, one-line diagrams, and other documents, Staff

8 believes this project delivers system benefits to Oregon customers. However,

9 Staff believes that this project incurred cost overruns, and that those should be

10 disallowed.

11 **Q. Why do you think the Vantage to Pomona Heights should be subject to**

12 **a disallowance?**

13 A. According to documents obtained by Staff, this project has currently estimated

14 significant cost overruns of roughly **[BEGIN CONFIDENTIAL]** [redacted].

15 **[END CONFIDENTIAL]**[36] The project was initially budgeted at **[BEGIN**

16 **CONFIDENTIAL]** [redacted] **[END**

17 **CONFIDENTIAL]** resulting in a total maximum original estimated cost of

18 **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[37] Requested

19 cost recovery in this case in Mr. Rick Vail's testimony is $57.3 million, which

20 exceeds the original budget by **[BEGIN CONFIDENTIAL]** [redacted]. **[END**

21 **CONFIDENTIAL]** Staff also recently received **[BEGIN CONFIDENTIAL]** [redacted]

22 [redacted]

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[36] See Staff Confidential exhibits 1405 and 2105.
[37] See Confidential Staff Exhibit Staff/1405.

1 [redacted],
2 [redacted]
3 [redacted] **[END CONFIDENTIAL]**[38] If the
4 project costs the full **[BEGIN CONFIDENTIAL]** [redacted] **[END**
5 **CONFIDENTIAL]**, this would amount to a total overrun of at least **[BEGIN**
6 **CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

7 **Q. What is the cause of these cost changes?**

8 A. The Company cites several reasons, including **[BEGIN CONFIDENTIAL]**
9 [redacted]
10 [redacted]
11 [redacted], **[END CONFIDENTIAL]**[39] increased
12 labor costs due to labor shortages, an increase in the number of rock drillings,
13 weather, new line configurations, among other issues.[40] Recently, there was
14 also a falcon's nest discovered at the construction site that forced the
15 Company to temporarily cease construction.[41] While some of these issues
16 may have been outside of the Company's control, the magnitude of this
17 overrun and extent of complications experienced by the Company is
18 concerning to Staff. Therefore, Staff recommends allowing the Company to
19 only recover costs at the estimated contingency, which was **[BEGIN**
20 **CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in this case. Staff
21 believes the original project funds should be capped at these original costs,

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[38] See Confidential Staff Exhibit 2105 (DR 150 Supplement).
[39] See Confidential Staff Exhibit 1405.
[40] See Staff Exhibit 2101 (DR 460).
[41] See Staff Exhibit 2101 (DR 460).

resulting in a disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** relative to PacifiCorp's requested cost recovery in this case. PacifiCorp would not be precluded from seeking cost recovery for additional costs in a future ratemaking proceeding.

Q. Did Mr. Vail address any of these issues in his testimony?

A. Yes. Mr. Vail illuminated some of the reasons behind the project interruptions, but did not discuss cost overruns. Despite repeated delays in this project, Mr. Vail believes it will be in service July 2020. He also reiterated the same recommendation modifications as with the Energy Vision 2020 projects and expressed some concerns with a cost cap because Staff had not recommended one in Opening Testimony.

Q. Other than the disallowance, do you have any other recommendations for this project?

A. Yes, like the Energy Vision 2020 projects, Staff recommends the following:

- PacifiCorp must file an attestation from an officer or a Vice President of either Pacific Power or Rocky Mountain Power that all requested wind and transmission buildout is in-service by the time rates go into effect. Components of the project not in-service by the target date of December 31, 2020, should be removed from revenue requirement.
- There should be a cost cap for rate recovery. Staff is recommending a disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for a total cost cap of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

- Any unrecovered balances beyond the cost cap would be subject to a future ratemaking proceeding.
- PacifiCorp must re-file for cost recovery for any projects that are not used and useful by December 31, 2020.

Q. In your Opening Testimony, you indicated that the Goshen-Sugarmill-Rigby project potentially does not deliver system benefits to Oregon customers. Do you still believe this?

A. Yes. From documents reviewed by Staff, and upon further scrutiny and analysis of testimony and discovery, Staff believes this project could provide some benefits. However, those benefits are local. The Company failed to provide evidence that those benefits will carry on to Oregon ratepayers. The Company did not provide any sort of load flow analysis or modeling that concluded that absent this project, reliability to Oregon rate payers would be compromised. Further, it is Staff's understanding that this project is allocated to Oregon merely on the basis that its voltage is generally considered to be transmission. In other words, regardless of function, the Company allocates *any* transmission to all states due to the size of the line. This means that radial lines and "transmission" sized projects that provide a distribution function are allocated to Oregon, despite the fact that these projects do not provide a benefit to Oregon ratepayers.

Q. Did Mr. Vail provide any evidence that this project delivers system benefits?

A. No. Mr. Vail indicated that it is not reasonable for the existing line to be included in rates, while the upgraded line (Goshen-Sugarmill-Rigby) that

provides more reliability to PacifiCorp's transmission system as a whole would not be included in rates. He also indicated that PacifiCorp's transmission system "provides benefits to all customers by allowing access to load and markets across a large part of the West."[42]

Q. What are your recommendations for the Goshen-Sugarmill-Rigby project?

A. Staff recommends that the entirety of the project be disallowed ($21.5 million, $5.6 million Oregon-allocated).

Q. In your Opening Testimony, you were also concerned that the SW Wyoming Silver Creek project did not deliver system benefits. Do you still believe that?

A. Yes. For similar reasons as the Goshen-Sugarmill-Rigby project, the Company has not provided sufficient evidence that this project provides system benefits. From documents reviewed by Staff, and upon further scrutiny and analysis of testimony and discovery, Staff believes this project could provide some benefits. However, those benefits are local.

The Company failed to provide evidence that those benefits will carry on to Oregon ratepayers. The Company did not provide any sort of load flow analysis or modeling that concluded that absent this project, reliability to Oregon rate payers would be compromised. Staff still believes this project primarily benefits the SW Wyoming area, not the primary grid. Thus, this entire

[42] PAC/2800, Vail/26.

project should be removed from Oregon rate base for a total disallowance of $41.9 million and $10.9 million Oregon allocated.

Q. Did Mr. Vail provide any evidence that this project delivers system benefits in his testimony?

A. No. Mr. Vail claimed that this project, which is a line being rebuilt, has historically been included in Oregon rates, and therefore that this current upgrade should also be included in Oregon rates. Mr. Vail also characterized PacifiCorp's transmission system as a "broader system including elements at voltages of 161 kV and 138 kV," that it provides "benefits to all customers by providing access to markets and generation resources," and that "Staff's concerns would mark a significant deviation from Commission precedent."[43] However, Mr. Vail also indicated that these transmission "benefits" would be "impossible" to track by segment.[44]

Q. Do you agree with Mr. Vail's characterization of PacifiCorp's transmission system?

A. No. Staff does not agree with the idea that all lower-voltage lines deliver system-wide benefits. Staff is deeply concerned that the Company has been improperly categorizing local (situs) projects as transmission and allocating costs across all six states in its service territory (Utah, Oregon, Idaho, Wyoming, Washington, and California).

Furthermore, just because the Company has been improperly categorizing a particular project as transmission in the OATT for years does not

[43] See PAC/2800, Vail 28.
[44] See PAC/2800, Vail 29.

mean that this project delivers system benefits that it is used and useful for Oregon ratepayers, or that it is a prudent investment. The Oregon Commission alone remains responsible for establishing just and reasonable rates for PacifiCorp's Oregon customers.[45] Staff discusses this issue in further depth under Issue 4 – Unverifiable Projects.

Q. What are your recommendations for the Threemile Canyon Farm project?

A. Based on Staff's project review through testimony, discovery, requested change orders, original budgets, one-line diagrams, and other documents, Staff believes this project delivers benefits to Oregon customers. However, Staff also believes that this project incurred cost overruns and that those should be disallowed.

Q. Why do you think project costs for the Threemile Canyon Farm project should be disallowed?

A. Staff identified a cost overrun of about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This was discovered in a change order and Staff compared this to the cost presented in Mr. Vail's testimony.[46] The amount requested in Mr. Vail's testimony is $6.2 million.[47]

Q. What was the reason for the cost overrun?

A. The Company stated various reasons, including **[BEGIN CONFIDENTIAL]**

[redacted]

[45] See UM 1050, Order No. 20-024.
[46] See Confidential Staff Exhibit 1405.
[47] See PAC/1000, Vail/11.

[redacted]. **[END CONFIDENTIAL]**[48] Staff cannot identify a reason for why these costs should be borne by ratepayers. Given the fact that the Company's most recent change order over-forecasted the cost of the project at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** but originally approved costs were about **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** Staff believes this disallowance to be a fair compromise.[49] The Company would not be precluded from seeking cost recovery in a future ratemaking proceeding based on evidence that clearly supports the cost-overruns.

Q. Did Mr. Vail address this project in his testimony?

A. Yes, but Mr. Vail only stated that because Staff had not yet identified a concern or recommendation, he could not appropriately respond.[50]

Q. Why do you believe there should be disallowances for Q0542 Pryor Mountain?

A. While Staff can agree that this project delivers system benefits by enabling additional wind generation, it appears to have incurred a potential cost overrun of at least **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[51] Staff calculated this number by comparing original project costs to what was ultimately projected in Confidential Work Paper 8.5 Pro Forma Plant Additions.[52] This project is not expected to be in service until December 2020,

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[48] See Confidential Staff Exhibit 1405.
[49] See Confidential Staff Exhibit 1405.
[50] PAC/2800, Vail/29.
[51] See Exhibit PAC/1309, McCoy/16 and Exhibit 2107.
[52] Exhibit PAC/1309, McCoy/16.

so there is time for the Company to incur additional cost overruns from July to December.

Q. What was the reason for the cost overrun?

A. The reason provided for the current cost overrun is that **[BEGIN CONFIDENTIAL]** [redacted][53] [redacted][54] [redacted][55] **[END CONFIDENTIAL]** Ratepayers should not be held responsible for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** A cost cap at the original budget approval is appropriate.

Q. What are your recommendations for this project?

A. Staff's recommendation for this project is the following:

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[53] See Staff Exhibit 2107.
[54] See Staff Exhibit 2107.
[55] See Staff Exhibit 2107.

- PacifiCorp must file an attestation from an officer or a Vice President of either Pacific Power or Rocky Mountain Power that requested transmission buildout is in-service by the time rates go into effect. Components of the project not in-service by the target date of December 31, 2020, should be removed from revenue requirement.
- There should be a cost cap for rate recovery. Staff is recommending a cap of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and a disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
- Any unrecovered balances beyond the cost cap would be subject to a future ratemaking proceeding.
- PacifiCorp must re-file for cost recovery for any projects that are not used and useful by December 31, 2020.

Q. Why do you believe there should be disallowances for the [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]?**

A. We do not believe this project provides system benefits. In reviewing the project details provided by the Company,[56] Staff learned that **[BEGIN CONFIDENTIAL]** [redacted][57] [redacted]

[56] See Staff Exhibit 2107.
[57] See Staff Exhibit 2107.

b[redacted].[58] **[END CONFIDENTIAL]** While the project does seem like it will provide load support for this particular customer, the Company has failed to demonstrate its value to the broader system, so to Staff it only appears to be a **[BEGIN CONFIDENTIAL]** [redacted] and thus, should be situs-assigned to Utah. **[END CONFIDENTIAL]** Thus, Staff does not believe this project is useful to Oregon ratepayers and recommends that these costs be disallowed. The Pro Forma cost provided by the Company is **[BEGIN CONFIDENTIAL]** [redacted].[59] **[END CONFIDENTIAL]**

Q. Why do you believe there should be disallowances for the [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]?**

A. Simply, this project seems to have costs above its original budget. The Company explains that **[BEGIN CONFIDENTIAL]** [redacted].[60] [redacted].[61] **[END CONFIDENTIAL]** This project appears to be a small part of a larger transmission project.

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[58] See Staff Exhibit 2107.
[59] Exhibit PAC/1309, McCoy/16.
[60] See Staff Exhibit 2107.
[61] See Staff Exhibit 2107.

While Staff agrees with the reliability benefits, the project seems to have incurred cost overruns of about **[BEGIN CONFIDENTIAL]** [redacted][62] **[END CONFIDENTIAL]** Staff arrived at this number by comparing the project approval given to Staff and what is estimated in the confidential Pro Forma spreadsheet. No reason for the cost overrun is given. Staff recommends that there be a cost cap at the originally estimated budget request of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. Why do you believe there should be disallowances for the [BEGIN CONFIDENTIAL] [redacted]. [redacted] **[END CONFIDENTIAL]?**

A. Staff requested original budgets, approval documents, change orders, and one-line diagrams for this project, but we never received them. However, the Company did send Staff system impact studies.[63] From these documents, the project seems to be similar to the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the sense that there is a singular customer with an expected load increase. In particular, **[BEGIN CONFIDENTIAL]** [redacted].[64] **[END CONFIDENTIAL]** Similar to the **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** it only appears to be a reinforcement project for a local **[BEGIN**

[62] See Staff Exhibit 2107.
[63] See Staff Exhibit 2108.
[64] See Staff Exhibit 2108.

1 **CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Thus, Staff
2 does not believe this project is useful to Oregon ratepayers and recommends
3 that it be disallowed. The Pro Forma estimate is **[BEGIN CONFIDENTIAL]**
4 [redacted][65] **[END CONFIDENTIAL]** Staff believes this cost should not be
5 borne by Oregon ratepayers.

[65] Exhibit PAC/1309, McCoy/16.

ISSUE 4 – UNVERIFIABLE PROJECTS

Q. What do you mean by "unverifiable projects?"

A. Unverifiable projects are those which Staff did not receive enough information of a sufficient quality to be able to verify function and/or cost. These projects make up the Pro Forma projects in Confidential Work Paper 8.5 – Pro Forma Plant Additions.[66] In addition, there were over **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** projects under one million dollars that totaled over **[BEGIN CONFIDENTIAL]** [redacted].[67] **[END CONFIDENTIAL]** The total disallowance for Pro Forma projects (excluding Goshen-Sugarmill Rigby and Vantage-to-Pomona Heights as these were already described as verifiable projects) is **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. What are your concerns with these projects?

A. Without providing the necessary, quality information to verify function and/or cost, the Company was unable to prove that the full list of Pro Forma projects were 1) appropriately categorized as system benefit projects, and 2) did not incur cost overruns. Staff was able to verify a few of these, as explained under Issue 3 above, but Staff did not receive one-line diagrams, change orders, interconnection studies, maps, approval documents, or contracts of consistent and detailed quality for all projects that would allow Staff to verify cost and function. Staff participated in two phone calls with the Company in an attempt

[66] Exhibit PAC/1309, McCoy/16.
[67] See Staff Exhibit 2104.

to verify function and cost, and while these helped for some of the projects, they did not help for all of them.

Q. Did Staff receive adequate information in order to verify costs and prudence for these Pro Forma projects?

A. No. As discussed above, Staff has been highly disappointed with the quality and consistency of information presented to us. For example, on May 14, Staff requested approval/budget documents for all projects under one million dollars in Data Request 529, subpart c. Staff never received these; instead, the Company re-sent a list of projects under $1 million that it had already sent in an earlier data request.[68] Further, the Company's delays, particularly during the months of March and April, made it difficult for Staff to make preliminary recommendations and do follow up discovery early enough to make recommendations in Opening Testimony.

Over **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** line items were presented by the Company in the Pro Forma work paper, including projects under $1 million. But the Company only provided Staff with appropriate documentation[69] for a select few of these projects. Staff has had to piece together a wide variety of disorganized information of inconsistent, and oftentimes, poor quality to make determinations about function and cost. For many projects, it was literally impossible to verify function. For example, a substantial portion of the Pro Forma costs **[BEGIN CONFIDENTIAL]** ([redacted]

[68] See Staff Exhibit 2101.
[69] "Appropriate documentation" includes one-line diagrams, budgets, approval documents, contracts, interconnection studies, maps, and other documents.

[redacted]) **[END CONFIDENTIAL]**[70] were categorized under various "buckets" that included various voltages and were located in various states.

Q. What did you ask the Company to get additional details for these buckets and other projects?

A. On April 3, 2020, Staff referred the Company to the Pro Forma spreadsheet and asked the Company to provide an itemized breakdown, including costs and in-service dates, of all Pro Forma projects.[71]

Q. What sort of information did the Company provide?

A. The Company provided nothing. Instead, the Company referred Staff to the very same Pro Forma spreadsheet Staff referenced in the data request.[72]

Q. What did you do next to get additional information about these projects?

A. In an effort to get more detailed information, Staff asked for one-line diagrams; all internal approval documentation, narrative descriptions including voltages, primary function of the project, and why each project is needed; and Staff also asked the Company to include all projects under one million dollars as part of its response.[73]

Q. What sort of information did the Company provide?

A. The Company provided high-level descriptions of most, but not all, of the projects. The Company only provided one-line diagrams and approvals for some projects, but not all. Overall, Staff did not receive the sort of granular

[70] See Exhibit PAC/1309, McCoy/16 for bucketed costs.
[71] See Staff Exhibit 2101.
[72] See Staff Exhibit 2101 (DR 226).
[73] See Staff Exhibit 2101.

information needed in order to be able to appropriately verify all investments. At this point, three months had passed after the Company filed its testimony on February 14, and Staff was still needing quality information about the Company's investments. Very notably, Staff never received any approval documents for any projects under one million. Instead, the Company referred Staff back to an earlier data request that contained a list of these projects when Staff asked for this information.[74]

Q. What did you do next to get additional information about these projects?

A. Staff asked for contracts of all projects in the Pro Forma spreadsheet and all projects under one million. Staff notes that we also asked for such contracts at the very beginning of the case, before the Company even filed testimony.

Q. What sort of information did the Company provide?

A. Initially, the Company objected to this request as being unduly burdensome.[75] Further, PacifiCorp told Staff that if we wanted to see the contracts, we would only have the option of reviewing them in-person as Oregon coronavirus cases were on the rise.[76] At this point, it was about a week before Staff's internal deadline for testimony, so Staff pressed to see electronic copies. This took several days. When we received the project contracts at last, these were primarily in the form of project orders, not master contracts that would have explained the purposes of the projects. Further, the number of projects in the

[74] See Confidential Staff Exhibits 2101, 2103, and 2107.
[75] See Staff Exhibit 2101 (DRs 745 and 746).
[76] See Staff Exhibit 2101 (DRs 745 and 746).

1 Pro Forma work paper, including projects under one million outnumber the
2 projects we received contracts for, so it is still unclear to whether the Company
3 provided all information requested. The final batch of contracts was not
4 received until Staff's testimony was due internally.

5 **Q. What did you do next to get additional information about these**
6 **projects?**

7 A. Staff scheduled a highly confidential phone call with Company experts on
8 July 15 to verify the purposes of projects.

9 **Q. Did the phone call help?**

10 A. In some ways. Staff was able to gain additional detail regarding the general
11 type of projects included in the Pro Forma list, as well as projects under $1
12 million. However, in other ways, it confirmed Staff's deep concerns that the
13 Company is including in its rate base projects that are rated under 100 kV as
14 beneficial to its overall transmission system when they are really local benefit
15 or situs projects for other states. The phone call helped clarify the purposes of
16 some projects, but Staff still needs to see the quality documentation we have
17 been requesting for months in order to be able to make any determination for
18 cost recovery.

19 **Q. Is there any other information that Staff requested to get a sense of**
20 **project functions?**

21 A. Yes. Staff plainly asked the Company how it determined what was situs and
22 what was system allocated.[77]

[77] See Staff Exhibit 2101 (DR 742).

Q. What was the Company's response?

A. The Company only indicated that "in accordance with the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol, distribution assets are situs assigned to the state where they are located and transmission assets are system allocated."[78]

Q. Is transmission a defined term in the 2020 Protocol?

A. No, not based on our review.

Q. So what does PacifiCorp consider transmission assets generally?

A. To Staff's knowledge, PacifiCorp considers "transmission" to be generally anything above 46 kV,[79] regardless of function within the utility's system. This understanding was confirmed on the July 15 technical workshop with the Company.

Q. Is there any other information that Staff requested to get a sense of project functions?

A. Yes. Staff asked PacifiCorp if it had performed a Seven-Factor test on all projects considered in this case.[80] This includes the projects in Mr. Vail's testimony, the Pro Forma work paper projects, and all projects under one million dollars.

Q. What is the Seven-Factor test?

A. In Order No. 888, FERC formulated a Seven-Factor test to determine whether certain facilities should be classified as transmission and therefore subject to

[78] See Staff Exhibit 2101 (DR 742).
[79] See PacifiCorp FERC Form No. 1 (ED. 12-87), Page 422.8.
[80] See Staff Exhibit 2101.

FERC jurisdiction, or whether they should be classified as local distribution and subject to state jurisdiction.[81] In general, FERC will defer to state Commissions if they perform the Seven-Factor test. The "seven factors" are:

1. Local distribution facilities are normally in close proximity to retail customers.
2. Local distribution facilities are primarily radial in character.
3. Power flows into local distribution systems; it rarely, if ever, flows out.
4. When power enters a local distribution system, it is not reconsigned or transported on to some other market.
5. Power entering a local distribution system is consumed in a comparatively restricted geographical area.
6. Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
7. Local distribution systems will be of reduced voltage.

Q. What was the Company's response to your question? That is, had the Company performed Seven-Factor tests on any projects in this case?

A. No. The Company indicated that it had not performed a Seven-Factor test on any projects at issue in this case.[82] Rather, it stated that the projects "are treated consistently with current usage and treatment of assets in PacifiCorp's Open Access Transmission Tariff [OATT]."[83]

Q. In light of all of this, what is your recommendation?

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[81] See FERC Order No. 888.
[82] See Staff Exhibit 2101. (DRs 740-741).
[83] See Staff Exhibit 2101. (DRs 740-741).

A. The Company has failed to prove that many of its "transmission" projects are, in fact, functioning as transmission such that they provide a benefit to the system, rather than an individual state or customer. Staff must therefore make the following recommendations:

1) Staff recommends disallowance for all projects Staff could not verify. This results in a disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for unverifiable Pro Forma projects. If Staff had the appropriate information, Staff would recommend disallowance of all projects under 100 kV that are outside the state of Oregon until the Company provides information that can be used to verify the function of the line. However, because many of the Pro Forma projects were grouped together in buckets of various voltages and locations, Staff was unable to calculate this cost. Anything under 100 kV is unlikely to deliver system benefits. For example, Staff is highly skeptical of the idea that a 46 kV upgrade delivering power to a Southwest Wyoming ammunition manufacturer, for example, could realistically deliver system benefits that would serve Oregon purposes. This position is consistent with the one Staff took in Portland General Electric's transmission asset reclassification case, UM 2031, in which the Oregon Commission determined that lower-voltage lines (e.g., under 100 kV) were not transmission assets.[84]

2) Staff recommends that an investigation be opened to examine the Company's categorization of transmission. All transmission above 100 kV should be subject to an investigation. As indicated above, all

[84] See Order No. 19-400.

transmission below 100 kV outside of Oregon should be automatically disallowed.

3) Given the magnitude of the disallowance, the Commission could consider authorizing a deferral in which annual revenue requirement costs for unverifiable transmission assets subject to the investigation could be tracked pending the outcome of the investigation. The verifiable projects that incurred cost overruns should be left out of this deferral bucket, which amounts to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** worth of disallowances outlined under Issue 3 – Verifiable Projects.

Q. Why do you believe that the voltage rating threshold for out-of-state projects that the Commission should deem appropriate for rate recovery in Oregon should be 100 kV?

A. Staff believes that the Commission should follow the 100 kV Bright Line Test. The 100 kV Bright Line is a North American Reliability Council (NERC) reliability and Bulk Electric System (BES) designation, not technically a FERC one.

In 2005, Congress expanded FERC's regulatory authority by enacting the Electricity Modernization Act of 2005 authorizing FERC to adopt and enforce mandatory technical reliability standards on facilities that comprise "bulk-power system." The bulk-power system includes "facilities and control systems necessary for operating an interconnected electric energy transmission network,"[85] but does not include facilities used in the local

[85] Pub. L. No. 109-58, tit. XIII, 119 State. 594, 941-86 (2005).

1 distribution of electric energy."[86] In 2007, and through assignment from
2 FERC, NERC developed BES Standards. On November 18, 2010, FERC
3 further directed NERC to revise the definition of the bulk electric system to
4 include all facilities necessary for operating the BES reliably.

5 **Q. Did the OPUC participate in this process?**

6 A. Yes. The OPUC authorized a team of Staff to work on the NERC drafting
7 team developing and improving a bright line core criteria for the BES. Our
8 designated Primary Team Leader was staff electrical engineer Jerry Murray,
9 supported by Matt Muldoon.

10 While the electrical generation resources, transmission lines,
11 interconnections with neighboring systems and associated essential
12 equipment operated at voltages of 100 kV or higher were included in the BES,
13 this did not include radial transmission facilities serving only load, nor those
14 transformers and substation equipment, which if unavailable would not take
15 out of service any 100 kV line segment.

16 **Q. Would you then recommend inclusion of out-of-state transmission**
17 **projects that are rated above 100 kV in rate base?**

18 A. Not necessarily. Unless the Company can provide evidence those projects are
19 necessary for the reliability of its BES in Oregon, those projects should be
20 considered local projects in their respective states, and should not be part of an
21 Oregon rate case. That is why Staff is recommending an investigation of all

[86] Id. Sec. 824o (a)(1)

projects that are rated above 100 kV, and automatic disallowance of projects under 100 kV.

ISSUE 5 – RECOMMENDATIONS

Q. What do you recommend?

A. Staff recommends the following:

Aeolus to Bridger

The Commission find Aeolus-to-Bridger (Segment D.2 of Energy Gateway) prudent, subject to the following recommendations:

- The Company must file an attestation from an officer or Vice President from Rocky Mountain Power or Pacific Power that all requested transmission buildout is in-service by the time rates go into effect. Components of the project not in-service by the target date of December 31, 2020, should be removed from revenue requirement.
- There should be a cost cap for rate recovery of $679 million.
- Any unrecovered balances should be subject to a future ratemaking proceeding.
- Require PacifiCorp to refile for cost recovery of A2B if its Commercial Operation Date (COD) is after December 31, 2020. PacifiCorp must re-file for cost recovery for any projects that are not used and useful.

For Q707 TB Flats 1 and Q712 Cedar Springs Wind 1

The Commission find Aeolus-to-Bridger prudent, subject to the following recommendations:

- The Company must file an attestation from an officer or a Vice President of either Pacific Power or Rocky Mountain Power that all transmission buildout is in-service by the time rates go into effect. Components of the

project not in-service by the target date of December 31, 2020, should be removed from revenue requirement.

- There should be a cost cap for rate recovery at $30.6 million and $61.7 million for Q707 TB Flats 1 and Q712 Cedar Springs Wind 1, respectively.
- Any unrecovered balances should be subject to a future ratemaking proceeding.
- Require PacifiCorp to refile for cost recovery of EV 2020 transmission projects' Commercial Operation Date (COD) is after December 31, 2020. PacifiCorp must re-file for cost recovery for any projects that are not used and useful.

Snow Goose Substation Project

Staff recommends that the Commission find this investment prudent.

Sigurd-to-Red Butte

Staff recommends that the Commission find this investment prudent.

NE Portland Upgrade Project

Staff recommends that the Commission find this investment prudent.

Pro Forma Projects:

Staff recommends that the Commission find the following projects prudent:

- **[BEGIN CONFIDENTIAL]** [redacted]
- [redacted]
- [redacted]
- [redacted]

1 • [redacted]

2 • [redacted]

3 • [redacted]

4 **[END CONFIDENTIAL]**

5 Wallula to McNary

6 Staff recommends that the Commission disallow **[BEGIN CONFIDENTIAL]**

7 [redacted] **[END CONFIDENTIAL]** in Oregon-allocated.

8 Vantage to Pomona Heights

9 Staff recommends that the Commission disallow **[BEGIN CONFIDENTIAL]**

10 [redacted] **[END CONFIDENTIAL]** in Oregon-allocated

11 costs. Any unrecovered balances beyond the cost cap would be subject to a

12 future ratemaking proceeding.

13 Goshen-Sugarmill-Rigby

14 Staff recommends that the Commission disallow $21.5 million, or $5.6 million

15 in Oregon-allocated costs. Any unrecovered balances beyond the cost cap

16 would be subject to a future ratemaking proceeding.

17 SW Wyoming Silver Creek

18 Staff recommends a total project disallowance of $41.9 million, or $10.9

19 million in Oregon-allocated costs.

20 Threemile Canyon Farm

21 Staff recommends the Commission disallow **[BEGIN CONFIDENTIAL]** [redacted]

22 [redacted] **[END CONFIDENTIAL]** in Oregon-allocated costs.

23

1 For the following Pro Forma projects, Staff recommends disallowance:

2 *Q0542 Pryor Mountain*: **[BEGIN CONFIDENTIAL]** [redacted]

3 **[END CONFIDENTIAL]** in Oregon-allocated costs. Staff also recommends

4 the following:

5 • PacifiCorp must file an attestation from an officer or a Vice President of

6 either Pacific Power or Rocky Mountain Power that requested

7 transmission buildout is in-service by the time rates go into effect.

8 Components of the project not in-service by the target date of

9 December 31, 2020, should be removed from revenue requirement.

10 • There should be a cost cap for rate recovery. Staff is recommending a

11 cap of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

12 • Any unrecovered balances beyond the cost cap would be subject to a

13 future ratemaking proceeding.

14 • PacifiCorp must re-file for cost recovery for any projects that are not

15 used and useful by December 31, 2020.

16 **[BEGIN CONFIDENTIAL]** [redacted]: **[END**

17 **CONFIDENTIAL]** Staff recommends the Commission disallow **[BEGIN**

18 **CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in

19 Oregon-allocated costs.

20 **[BEGIN CONFIDENTIAL]** [redacted]: Staff

21 recommends the Commission disallow [redacted] **[END**

22 **CONFIDENTIAL]** in Oregon-allocated costs.

[BEGIN CONFIDENTIAL] [redacted] : **[END CONFIDENTIAL]** Staff recommends the Commission disallow **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in Oregon-allocated costs.

Unverifiable Projects and Transmission Investigation

- Staff recommends disallowance for all projects Staff could not verify. This results in a disallowance of **[BEGIN CONFIDENTIAL]** [redacted] or [redacted] **[END CONFIDENTIAL]** in Oregon-allocated costs for unverifiable projects.
- Staff recommends that an investigation be opened to examine the Company's categorization of transmission. All transmission above 100 kV should be subject to an investigation. As indicated above, all transmission below 100 kV outside of Oregon should be automatically disallowed.
- Given the magnitude of the disallowance, the Commission could consider authorizing a deferral in which annual revenue requirement costs for unverifiable transmission assets subject to the investigation could be tracked pending the outcome of the investigation. The verifiable projects that incurred cost overruns should be left out of this deferral bucket, which amount to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** worth of disallowances outlined under Issue 3 – Verifiable Projects.

Q. Does that conclude your testimony?

A. Yes.

CASE: UE 374
JOINT STAFF WITNESSES: HANHAN-RASHID-MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2101

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Oregon
Kate Brown, Governor

Public Utility Commission
3930 Fairview Industrial Dr SE
Salem, OR 97302-1166
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: 503-378-6600
Administrative Services
503-373-7394

March 19, 2020

DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 2000
PORTLAND, OR 97232
datarequest@pacificorp.com

RE:	Docket No.	OPUC Request Nos.	Response Due By
	UE 374	OPUC 143-175	April 2, 2020

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

Topic or Keyword:

143. See PAC/1000, Vail/5-6.

   a. Please provide all annual and two year system assessments the Company is relying on for this rate case.

   b. Please explain how the Company identified system deficiencies.

   c. Are there any system deficiencies the Company has identified that it is asking for cost recovery in this rate case?

   d. Regarding part c., please provide a list of such system deficiencies and any work papers, with costs broken down by line item, of these investments.

   e. Please identify whether each transmission project segment and associated substation has been acknowledged in a specific OR IRP and if each condition therein was met.

   f. What transmission projects and/or related transmission substations or upgrades thereto are incomplete at the moment and not now in service.

g. Please show the target in-service date for each element identified in part f.

144. See PAC/1000, Vail/11, Table 1. For each of the projects the Company is requesting cost recovery for:

a. Please provide a project timeline from start to finish.

b. Please provide the costs, by line-item, of each project in Excel format with cell formulae intact.

c. Please indicate which of these projects have been previously acknowledged or not in an Oregon IRP, and in which Commission Order it was acknowledged or not acknowledged.

d. If any of these projects were acknowledged in an IRP, please provide the difference in costs between what was projected in an IRP and what actual costs the Company is asking recovery for.

e. Please itemize and provide a narrative justifying each loading associated with a cost escalation in part d.

f. Has the Company obtained all the required approvals for each of these projects (i.e., CPCNs and land use permits)? If not, please provide a list of approvals still required for construction of each of these projects and the anticipated timeline for a decision.

g. Please provide any and all interconnection studies associated with these projects (e.g., System Impact Study, Feasibility Study, and Facilities Study).

145. See PAC/1000, Vail/8. The Company states, “The Aeolus to Bridger/Anticline 500 kV Transmission Project and 230 kV Network Upgrades are needed to support interconnection of the new Energy Vision 2020 Wind Projects.” Does the Company intend to say that, but for the wind projects, the Company would not have moved forward with the Aeolus to Bridger/Anticline transmission line and associated Network Upgrades? If yes, explain why. If not, explain why not.

146. See PAC/1000, Vail/8.

a. What is the transfer capability of the Wallula to McNary transmission line?

b. Please provide the hourly historic flows across the Wallula to McNary 230 kV line since its energization date.

c. Please clarify whether this line segment has been acknowledged by the Commission, and if not, on what basis the Company is proceeding.

147. See PAC/1000, Vail/15, lines 10-14.

a. Please explain how the Aeolus to Bridger project supports the Company’s “short-term” energy demands as referenced in testimony.

b. Please explain how the Aeolus to Bridger project supports the Company’s “long-term” energy demands as referenced in testimony.

c. How does this project serve the overall reliability of the Wyoming transmission system? Please provide all studies, engineering studies, both internal and external supporting this conclusion.

d. How does this project serve the overall reliability of PacifiCorp's transmission system? Please provide all studies, engineering studies, both internal and external supporting this conclusion.

e. How does this project support the PacifiCorp system in ways other than reliability? Please provide all studies, engineering studies, both internal and external supporting this conclusion.

148. See PAC/1000, Vail/15, lines 15-21.

a. What is the Company's justification for making an "economic connection" between the wind resources and the Aeolus to Bridger transmission line? That is, what is the Company's justification for "buying down" the cost of the transmission line with production tax credits from a generation resource?

b. In the potential event that the wind generation fails to be constructed or is uneconomic, how will this affect the cost-effectiveness of the Aeolus to Bridger transmission project?

c. See part b of this question. Is the Company aware of any other utility that has employed this economic approach to estimating transmission costs?

149. For each transmission line and associated build for which the Company is asking for cost recovery in this case, what cost estimators from the Western Governors Association or other sources did the Company use to consider whether cost estimates to build these transmission resources were costed correctly?

150. For each transmission line and associated build for which the Company is asking for cost recovery in this case, please provide all change orders and a narrative explaining the cause for the change. This is an **ongoing request** – please send additional change orders and associated narrative as additional change orders occur.

151. For each transmission line and associated build for which the Company is asking for cost recovery in this case, do or will the contracts for construction both reduce as well as ratchet up or increase costs for build based on changes in the costs of each of a) steel, b) structural steel, c) copper and d) aluminum? If not please explain why not.

152. For each transmission line and associated build for which the Company is asking for cost recovery in this case, please explain each escalation in cost due to a) different than expected hydrology, b) different than expected geology or rock hardness, c) different than expected elevation changes and d) different than expected direction changes.

153. For each transmission line and associated build for which the Company is asking for cost recovery in this case, please explain whether lightning lines or similar technology will be used by the Company or third parties to provide internet or other fiber optic connectivity, and b) whether cash flows therefore are applied to reduce the cost of build to electric utility ratepayers.

154. See PAC/1000, Vail/17, lines 7-10. Please explain how the Company arrived at the 1510 MW number. Please provide any studies, reports and analysis supporting this number.

155. See PAC/1000, Vail/17. The Company states, "…the Aeolus to Bridger/Anticline 500 kV Transmission Project is not specifically mandated by the Company's obligations under its OATT…"

   a. Please elaborate on why the Company is not mandated to build Aeolus to Bridger under the OATT.

   b. How does this lack of obligation compare with Gateway South?

156. See PAC/1000, Vail/20-21. For the question starting on line 10, please provide a map or graphical representation for **each** of the examples demonstrating how Aeolus to Bridger benefits outages on 230 kV lines.

157. See PAC/1000, Vail/22, lines 8-18. Please provide a map or graphical representation for **each** of the examples demonstrating how Aeolus to Bridger helps meet NERC standards.

158. Please provide the WECC path rating study for Aeolus to Bridger.

159. See PAC/1000, Vail/26, lines 14-16. Please provide an update to this question.

160. Please explain the difference between "mechanical completion" and "substantial completion" as listed on PAC/1000/Vail/28.

161. See PAC/1000, Vail/29, lines 5-8.

   a. Please elaborate on this paragraph.

   b. Please clarify what is meant by, "The Company expects that transmission customers will contribute to the cost of the 230 kV transmission interconnections."

   c. Referencing part b above, how are transmission customers going to contribute to these transmission interconnection costs? Please provide an estimate of this number and any workpapers used to calculate these contributions.

   d. Please clarify what is meant by, "The 230 kV transmission facilities identified to integrate the Aeolus to Bridger/Anticline single-circuit 500 kV line with the existing Wyoming transmission system are considered network upgrades." Why are they considered network upgrades?

162. See PAC/1000, Vail/30. PacifiCorp states that "the Company would treat a completed and functional wind turbine as being placed in-service regardless of any transmission constraints affecting a wind project." Does this mean that if a turbine is complete, but the Aeolus to Bridger project is not, that the Company will still consider the wind turbine "in-service?" If so, why?

163. Does the Company have a forecast of third-party revenues for transmission service, along with third-party revenues for ancillary services? If so, please provide these. Please also provide any work papers estimating third party revenues from expected

transmission service, including ancillary service revenues, for the Aeolus to Bridger transmission project.

164. See PAC/1000, Vail/33, 6-8.

   a. Please provide all TPL standards that the Company is relying on to justify the Snow Goose transmission project.

   b. Please provide additional detail as to how the Snow Goose project will allow the Company to meet TPL standards.

165. See PAC/1000, Vail/36-37.

   a. Please provide the internal studies referenced on line 6.

   b. Please provide the 2007 study referenced in line 7.

   c. Please provide the NERC screening studies referenced in lines 7-10.

   d. Were the outages and deficiencies referenced in this section observed/historical outages and deficiencies, or were they anticipated based on the internal, NERC, and Northwest Transmission Assessment Committee (NTAC) or similar studies?

   e. Were the eight combinations of outages and deficiencies identified in lines 13-15 observed/historical outages or were they anticipated ones based on NERC, NTAC, and internal studies?

   f. Has the Company ever had to shed Yakima area load as identified in line 22, page 36? If so, please provide documentation of such circumstances and specific contingencies identified.

   g. Regarding the question directly above, please also indicate whether these contingencies, if any, are among the eight identified on line 1, page 37.

166. See PAC/1000, Vail/37, lines 15-18. How many years is the Vantage-Pomona project expected to mitigate deficiencies?

167. Please provide the 2016 Goshen Area Planning Study referenced on PAC/1000, Vail/39, line 7.

168. Has the Company historically experienced overloads or other contingencies on the Goshen to Sugarmill 161 kV line? If so, please provide documentation of such circumstances.

169. See PAC/1000, Vail/44, lines 12-14. The Company states, “Further, in order to provide low-cost energy, the Company must have the ability to acquire power from numerous generation sources in order to negotiate the most competitive pricing.”

   a. Please elaborate on this statement.

   b. What is meant by “low-cost energy?”

   c. What is meant by “ability to acquire power from numerous generation sources in order to negotiate the most competitive pricing?”

170. See PAC/1000, Vail/44, line 9. What is meant by “increased and unacceptable risk?”

171. See PAC/1000, Vail/51, lines 14-15. Please further elaborate on the statement, “It should be noted that the required energy output greatly exceeded the available energy input.”

172. Regarding the Threemile Canyon Farm Project:

    a. Is Threemile Canyon Farm, LLC assisting with the cost of this project? If so, what percentage of the cost is it contributing?

    b. What is the Electric Services Study Agreement process referenced on PAC/1000, Vail/55, line 1? How does it differ from regular interconnection processes and studies?

    c. Please provide the Electric Services Study Agreement.

173. Please identify and provide a narrative for each piece of transmission substation equipment valued over $1 million that the Company has or will arrange to install directly rather than rely on turnkey contractors who assume liability for mishandling crane lifts or installation failures.

174. Please provide the Company’s risk mitigation and cost control guidelines and a narrative on how each of the builds seeking cost recovery complied with said guidelines to control cost and risk for ratepayers.

175. What wildfire enhancements or other resilience features are part of the transmission and associated builds or upgrades, and what was the incremental cost for said enhancements?

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the “Sharing” feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

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Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to puc.datarequests@state.or.us.

/s/ Marianne Gardner, E-RFA, Manager Rates and Accounting

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April 3, 2020

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RE:	Docket No.	OPUC Request Nos.	Response Due By
	UE 374	OPUC 225-228	April 17, 2020

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

Topic or Keyword: Transmission and Distribution

225. Please refer to Confidential Workpaper Pro Forma Plant Additions_CONF, tab 8.5.21_CONF, cell E61. Please provide:
    a. An itemized breakdown of all the projects that make up this dollar amount.
    b. The in-service date of each project.
    c. The location of each project.
    d. Any and all interconnection studies associated with these projects (e.g., System Impact Study, Feasibility Study, and Facilities Study).
226. Please refer to Confidential Workpaper Pro Forma Plant Additions_CONF, tab 8.5.21_CONF, column A.
    a. Please provide an itemized breakdown, including costs and in-service date, of all projects in Column A.
    b. Please provide a narrative description of the all the projects in cells A8 **through** A24.

c. Were any of these projects acknowledged in an IRP? If so, please provide the difference in costs between what was projected in an IRP and what actual costs the Company is asking recovery for.
d. Please provide any and all interconnection studies associated with these projects (e.g., System Impact Study, Feasibility Study, and Facilities Study).

227. Please refer to Confidential Workpaper Pro Forma Plant Additions_CONF, tab 8.5.22 – 8.5.23, cells A9, A13, A16, and A29. Please provide narrative descriptions of each of these projects.
228. Please refer to Confidential Workpaper Pro Forma Plant Additions_CONF, tab 8.5.22 – 8.5.23, cell A105. Please provide:
    a. An itemized breakdown, including cots, of all the projects that make up this dollar amount.
    b. The in-service date of each project
    c. The location of each project.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the “Sharing” feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

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Questions regarding the use of Huddle should be directed to puc.datarequests@state.or.us.

/s/ Marianne Gardner, E-RFA, Manager Rates and Accounting

Staff Initiator: Nadine Hanhan Nadine.hanhan@state.or.us (503) 931-0161

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May 5, 2020

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RE:	Docket No.	OPUC Request Nos.	Response Due By
	UE 374	OPUC 444-462	May 19, 2020

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

Topic or Keyword: Transmission

DR 444 TO DR 461 ARE CONFIDENTIAL

462. Please see Company response to Staff DR 150, Attachment labeled "Wallula-McNary_PCN 94008745 04-11-18.pdf.
    a. Please explain the discrepancy in the estimated number from 2018 and the $42.6m requested in PAC/1000/Vail/11.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

You must mark confidential responses as such and post them to Huddle in the appropriate "Confidential" folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to puc.datarequests@state.or.us.

/s/ Matt Muldoon, E-RFA, Manager Economic Analysis

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May 5, 2020

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RE:	Docket No.	OPUC Request Nos.	Response Due By
	UE 374	OPUC 463-504	May 19, 2020

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

Topic or Keyword: Transmission

463. For each project listed in PAC/1000/Vail/11, please identify:
    a. Whether the Company evaluated or considered non-wires alternatives. This includes, but is not limited to, battery storage, conservation measures, construction of one or more lower-voltage single or multi-circuit lines, or an agreement to allocate territory or customers to another electric service provider.
    b. What non-wires alternatives the Company considered.
    c. Why the non-wires alternatives were rejected and why the Company opted to proceed with the project.
464. For all projects listed in PAC/1000/Vail/11, please identify:
    a. Any affiliates that would be associated with providing any services related to these projects.
    b. Any affiliated interest contracts approved by the Commission through which any of these projects were purchased.
465. Please explain whether for each project for which cost recovery is requested in this general rate case, another division of Berkshire Hathaway (other than PacifiCorp) has

an ownership stake in or rights to capacity of that new or upgraded facility, identifying said share.

466. Please explain whether for each project for which cost recovery is requested in this general rate case, BPA has an ownership stake in or rights to capacity of that new or upgraded facility, identifying said share.

467. Please explain whether for each project for which cost recovery is requested in this general rate case, an entity other than a Division of BRK or BPA has an ownership stake in or rights to capacity of that new or upgraded facility, identifying said entity and share.

468. For all projects listed in PAC/1000/Vail/11, please identify:
   a. Whether any internal audits were conducted as it pertains to any of these projects.
   b. Please provide the internal audits, if any.

469. For all projects listed in PAC/1000/Vail/11, please identify:
   a. Any RFPs associated with these projects.
   b. Please provide all RFP documents associated with any of these projects, including but not limited to initial request for proposal, shortlists results, final selection, and justification for why the winning bid was selected.

470. For all projects listed in PAC/1000/Vail/11, please provide:
   a. All internal decision-making documents that approved each of these projects, including but not limited to reports to senior management and internal memos.

471. For all projects listed in PAC/1000/Vail/11, please identify:
   a. Whether there were any studies performed assigning reliability costs.
   b. Please provide all such studies.

472. For all projects listed in PAC/1000/Vail/11, please provide:
   a. Average expected capacity utilization at the time the decision to proceed with the project was made. In your answer, please provide a date at which decisions to proceed were made.
   b. Current average capacity utilization for the project if in service.
   c. Future average expected capacity utilization for projects not yet in service.
   d. All past, current, and expected transmission customers and their utilization of each transmission line, if any.

473. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. See tab Q712. Throughout this spreadsheet tab, the Company references the Windstar substation and associated costs.
   a. Is this Windstar substation upgrade related to Cedar Springs the same upgrade needed for Segment D.1 of Energy Gateway?
   b. Is the Company still intending on building the Windstar-to-Aeolus transmission line (Segment D.1 of Energy Gateway)? If so, please explain why. If not, please explain why not.
   c. Is transmission line Segment Windstar-to-Aeolus needed to export Cedar Springs wind power to load?

d. Will transmission Segment Windstar-to-Aeolus be needed to export Cedar Springs power to load at any point in the future?
e. Please provide all interconnection studies related to the Windstar substation and Windstar-to-Aeolus transmission line.

474. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs.
   a. Please provide a narrative explanation of the "WBS Element" tabs.
   b. Please provide a narrative explanation of the "Object" tabs. Why are some "Objects" numbers and why do others correspond identically to the "WBS Element" tabs?

475. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. For each of the transmission projects listed in PAC/1000/Vail/11, please explain the discrepancies between what the Company is requesting in Table 1 of Rick Vail's testimony and the Project Costs "Grand Totals" on each project tab. For example, Table 1 in testimony asks for $679.1 million in cost recovery, but the Aeolus to Bridger tab shows a grand total of only $528,060,948.76.

476. Please see each transmission project listed in PAC/1000/Vail/11. Please provide:
   a. All original project budgets.
   b. Any updated project budgets.
   c. Any communications, internal memos, work papers and presentations reported to the Company's VP of Transmission and Distribution justifying every projects. If projects were not presented to the VP of Transmission and Distribution, please provide the same documentation delivered to the next-highest level of management approving the project.
   d. For all projects that had a change order, please provide any communications, internal memos, work papers and presentations reported to the Company's VP of Transmission and Distribution justifying each change order. If projects were not presented to the VP of Transmission and Distribution, please provide the same documentation delivered to the next-highest level of management approving the project.

477. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Aeolus to Bridger Anticline" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any workpapers in Excel format with cell formulae intact:
   a. Aeolus Substation Construction (note: spreadsheet spells it "Constuction.")
   b. Jim Bridger Substation Construction
   c. Latham Substation Statcom
   d. Permitting and Environmental
   e. Preconstruction Substation
   f. Preconstruction TLine
   g. Right of Way

h. TLine Aeolus-Anticline 500kV

478. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Aeolus to Bridger Anticline" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Capital Accruals - Not in AFUDC Base
   b. Capital Surcharge Manual Adjustments
   c. Consulting/Technical Services
   d. Contract Construction - Spec Apprv Reqd
   e. Contract Line Construction/Maintenance
   f. Environmental Services
   g. Interest Exp-AFUDC Auto Calc - Equity
   h. Rights of Way Expense

479. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Q707" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Q707 TBF1 Shirley Basin-Aeolus #2 TLine
   b. Q707 TBF1 Shirley Basin Substation

480. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Q707" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Capital Surcharge Manual Adjustments
   b. Contract Line Construction/Maintenance

481. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Q712" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Q712 Aeolus-Freezeout-Standpipe TLine
   b. Q712 Freezeout Substation
   c. Q712 Shirley Basin - Aeolus #1 Tline
   d. Q712 Windstar Substation

482. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Q712" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Capital Surcharge Manual Adjustments
   b. Engineering Services
   c. Environmental Services

d. Contract Line Construction/Maintenance

483. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "w2ula McNary" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Walla Walla - McNary ROW
   b. Sub work – Wallula
   c. Wallula - McNary - Transmission Line
   d. MCNARY - WALLULA 230kV NEW LINE (OREGON)
   e. MCNARY-WALLULA 230KV NEW LINE (OREGON)
   f. MCNARRY-WALLULA 230KV (WASHINGTON)
   g. MCNARY-WALLULA 230KV (WASHINGTON)
   h. Walla Walla - McNary Permitting
   i. Wallula - McNary 230kV Ln Permitting

484. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Wallula McNary" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Contract Line Construction/Maintenance
   b. Interest Exp-AFUDC Auto Calc - Debt
   c. Interest Exp-AFUDC Auto Calc - Equity
   d. Miscellaneous Contracts & Services
   e. Rights of Way Expense

485. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Snow Goose" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Snow Goose 500kV Substation
   b. Snow Goose 230kV Substation
   c. Snow Goose 500kV Engineering

486. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Snow Goose" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any workpapers in Excel format with cell formulae intact:
   a. Contract Line Construction/Maintenance
   b. Transformers

487. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Vantage Pomona" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any work papers in Excel format with cell formulae intact:

a. Vantage Pomona Hghts 230kV Permit/Constr
b. Pomona Sub Ph3 Vantage Ln Installation
c. POMONA-VANTAGE 230 KV LINE.

488. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Vantage Pomona" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any workpapers in Excel format with cell formulae intact:
a. Contract Line Construction/Maintenance
b. Miscellaneous Contracts & Services
c. Interest Exp-AFUDC Auto Calc – Equity
d. Environmental Services

489. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Goshen-Sugrml-Rigby" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any work papers in Excel format with cell formulae intact:
a. Goshen-Sugarmill 69-161kV Upgrade

490. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Goshen-Sugrml-Rigby" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any work papers in Excel format with cell formulae intact:
a. Capital Accruals - Not in AFUDC Base
b. Contract Line Construction/Maintenance

491. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Sigurd-Red Butte" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any work papers in Excel format with cell formulae intact:
a. SIGURD-RED BUTTE 345 KV LINE SEGMENT #1
b. SIGURD-RED BUTTE 345 KV LINE SEGMENT #2
c. SIGURD-RED BUTTE 345 KV LINE SEGMENT #3
d. SIGURD-RED BUTTE 345 KV LINE SEGMENT #4
e. SIGURD-RED BUTTE 345 KV LINE SEGMENT #5
f. Red Butte Substation Modification
g. Right of Way Sigurd-Red Butte 345kV
h. Sigurd Substation Modification

492. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Sigurd-Red Butte" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr."

column. In your answer please include any work papers in Excel format with cell formulae intact:

a. Capital Surcharge Manual Adjustments
b. Consulting/Technical Services
c. Contract Construction - Spec Apprv Reqd
d. Contract Line Construction/Maintenance
e. Engineering Services
f. Environmental Services
g. Interest Exp-AFUDC Auto Calc - Debt
h. Interest Exp-AFUDC Auto Calc - Equity
i. Journeyman
j. Permits & Licenses
k. Property Tax

493. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "NE_PDX Upgrade" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any work papers in Excel format with cell formulae intact:

a. Parkrose Substation
b. Columbia Substation, Sub
c. Albina Substation Phase 1, Sub
d. Albina Substation Phase 2, Sub
e. Vernon Sub, Sub
f. Sub work - Parkrose Substation

494. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "NE_PDX Upgrade" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any workpapers in Excel format with cell formulae intact:

a. Breakers and Switches
b. Construction Overheads
c. Contract Line Construction/Maintenance
d. Journeyman P&D
e. Transformers

495. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "SW WY-Slvr Crk Bld" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any workpapers in Excel format with cell formulae intact:

a. Croydon: New 138-46kV Sub Transmission
b. Coalville Substation
c. COALVILLE-SILVERCREEK 138KV SEC 120-190

d. COALVILLE-SILVERCREEK 138KV SEC 210-230

496. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "SW WY-Slvr Crk Bld" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any workpapers in Excel format with cell formulae intact:
   a. Constr & Maint Contracts-Other
   b. Contract Line Construction/Maintenance
   c. Engineering Services
   d. Interest Exp-AFUDC Auto Calc - Equity

497. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Threemile Wind Canyon" tab. Please provide **a detailed narrative** and breakdown of costs of the following cell data listed under the "CO object name" column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Threemile Canyon Farm 2,500 HP Incr ESSA

498. Please see PacifiCorp's Response to Staff DR 144, Attachment OPUC 144-1, Project Costs. Please see the "Threemile Wind Canyon" tab. Please provide a detailed narrative and breakdown of costs of the following cell data listed under the "Cost element descr." column. In your answer please include any work papers in Excel format with cell formulae intact:
   a. Contract Line Construction/Maintenance

499. Regarding current events pertaining to the novel coronavirus and transmission project completions:
   a. Is the Company aware of any supply chain challenges due to the novel coronavirus that will impact any transmission and generation projects requested in this rate case? For example, if a transformer with an anticipated delivery date of 6/10/2020 is likely to be held up due to international global supply chain issues.
   b. If the Company is aware of any current challenges that would impact the in-service date of any transmission or generation project, please provide all internal memos, analytics, presentations, work papers, and communications identifying these challenges. This is an ongoing request, that is not terminated until each applicable project is energize and in service.

500. For all projects listed in PAC/1000, Vail/11, please provide all communications, presentations, internal memos, and any associated work papers presented to PacifiCorp's VP of Transmission and Distribution justifying these projects. In your answer please include any budget updates over time, explanations of any cost escalations or de-escalations, and a narrative explanation of changes in project costs.

501. For **each** project listed in PAC/1000, Vail/11:
   a. Please provide all primary engineering construction build cost amounts.
   b. Please provide the fully loaded costs of the projects.
   c. If there are any discrepancies between costs requested in PAC/1000/Vail/11 and fully loaded costs, please explain these discrepancies.
   d. Please provide the cost difference between primary engineering construction build costs and fully loaded final costs for the Mona to Oquirrh transmission project. Please provide this in Excel format with clear demarcation of cost overruns (or lack thereof).
   e. Please provide the cost difference between primary engineering construction build costs and fully loaded final costs for the Populus-to-Terminal transmission project. Please provide this in Excel format with clear demarcation of cost overruns (or lack thereof).
   f. Where the delta between "a." and "b." exceeds the delta between "d." and "e," please provide a narrative of the cost differentials.
   g. Where the delta between "a." and "b." as a percentage of primary engineering construction build cost exceeds the delta between "d." and "e," as a percentage of primary engineering build cots, please provide a narrative of the cost differentials.

502. Regarding building contracts for projects referenced in PAC/1000, Vail/11:
   a. Please describe what type of build contracts the Company relied on for each project in which PAC/1000/Vail/11 (i.e., EPC or BTO or otherwise).
   b. Wherever the Company relied on a third party contractor, are there any penalties or reductions if the third party does not meet the contract terms? If so, please describe and provide any penalties.
   c. Please provide a list of all contract violations, if any, and how they were addressed. This is an ongoing data request in effect until PacifiCorp has accepted each pertinent project from contractors and it is energized and in service.

503. Given the linked Executive Order, what delays and cost overruns will PAC incur to comply with US-made control and communication systems for all US Bulk Power System components down to 69 kV?

504. Regarding the Sigurd-to-Red Butte project:
   a. Please provide the hourly, average, and aggregate southwest Utah load projections made in the 2013 IRP.
   b. Please provide all actual hourly, average, and aggregate loads in southwest Utah since the 2013 IRP to present day.
   c. Please provide all transmission customer transactions since the Sigurd-to-Red Butte energization date.
   d. To where, and from where, does power from Sigurd-to-Red Butte generally flow? In your answer, please provide a current narrative assessment of capacity utilization over the Sigurd-to-Red Butte transmission line.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the “Sharing” feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

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Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.
Questions regarding the use of Huddle should be directed to puc.datarequests@state.or.us.

/s/ Matt Muldoon, E-RFA, Manager Economics Analysis

Staff Initiator: Nadine Hanhan Nadine.hanhan@state.or.us (503) 931-0161

Oregon

Kate Brown, Governor

Public Utility Commission
3930 Fairview Industrial Dr SE
Salem, OR 97302-1166
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: 503-378-6600
Administrative Services
503-373-7394

May 14, 2020

DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 2000
PORTLAND, OR 97232
datarequest@pacificorp.com

RE:	Docket No.	OPUC Request Nos.	Response Due By
	UE 374	OPUC 525-533	May 28, 2020

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

Topic or Keyword: Transmission

525. Please see PacifiCorp Attachment 146. Please provide further detail on what the columns represent.
    a. In your answer, please explain to where, and from where, the flows are going.
    b. What do the positive values in the Wallula-Hat Rock (Interstate Line) column represent?
    c. What do the negative values in the Wallula-Hat Rock (Interstate Line) column represent?
    d. Please define what the column headings mean (i.e., Wallula-Hat Rock (Interstate Line), Column2, Column3, Wallula-McNary Line #2, Column4, Column5).
526. Please refer to PacifiCorp response to Staff DR 158, Attachment Aeolus West (3-30-18)Trans Asmt.pdf. Please see page 3 of this attachment, where the Company states, "The analyses identified two outages with poor voltage performance, and another outage identified a wind turbine modeling problem. These issues are all attributed to the wind turbine models at the Q0706, Q0707 and Q0708 projects. PacifiCorp is working with the wind turbine manufacture to resolve these issues."

a. Please provide additional detail as to these turbine issues. What are the issues? What has the Company done or is doing to rectify these issues?
b. Have these turbine issues been resolved? If so, please explain. If not, please explain why not, and when these issues expect to be resolved.

527. Please see PacifiCorp response to Staff DR 169. Please refer to subpart b.
    a. Is the Company still considering purchases of natural gas as an energy resource at the Harry Allen Emery hub? If yes, please explain. Please also explain when the Company foresees it will acquire this resource.
    b. If it is not considering Harry Allen Emery hub prices, please explain why not.
    c. Has PacifiCorp indeed acquired the "low-cost energy" from energy providers that have access to the Eldorado Valley (California Independent System Operation, Los Angeles Department of Water and Power, Western Area Power Administration, Arizona Public Service Company, SRP, etc.) and/or NV Energy?
    d. Please explain how construction of S2RB has advanced these developments **in the present**?
    e. If S2RB has not advanced these developments, please explain why.
528. Please see PacifiCorp response to Staff DR 225. See the Company's confidential attachment OPUC 225-1 CONF. For all projects listed in this spreadsheet, please provide all internal approval documents as listed on pages 5-8 in PacifiCorp's confidential Corporate Governance and Approvals Process (See Attach OPUC 174-1 CONF).
529. Please refer to Confidential Workpaper Pro Forma Plant Additions_CONF, tab 8.5.21_CONF, column A.
    a. For all projects listed in Column A, please provide all internal approval documents as listed on pages 5-8 in PacifiCorp's confidential Corporate Governance and Approvals Process (See Attach OPUC 174-1 CONF).
    b. In your answer, please also indicate which projects in Column A, if any, are associated with/correspond with the projects outlined in PAC/1000, Vail/11.
    c. In your answer, please include all individual projects that make up the dollar amount in cell E61.
530. Please provide one-line diagrams of all projects listed in PAC/1000, Vail/11. For projects in which the Company has already provided Staff with one-line diagrams, please refer Staff to the appropriate discovery attachments and responses.
531. Please refer to Confidential Workpaper Pro Forma Plant Additions_CONF, tab 8.5.21_CONF, column A.
    a. Please provide one-line diagrams for all projects in Column A.
    b. Please provide a narrative description of all projects in Column A.
    c. Please provide a narrative description of each of these projects in Column A. In your answer, please include voltages of the projects if applicable, primary function of the project, and why each project is needed.
    d. In your answer, please also include all individual projects that make up the dollar amount in cell E61.

532. Regarding construction for any transmission lines in the Walla Walla, Wallula, or McNary areas for which PacifiCorp wants cost recovery in this rate case:
    a. Has PacifiCorp had to halt construction in these areas due to COVID-19 challenges, or for any other reason?
    b. Has any other capital spending for projects located in Washington been affected?
    c. If capital spending has been affected, what are new project in-service dates?
533. Were there construction pauses in other states due to State or Federal COVID-19 related restrictions, or for any other reason?

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the “Sharing” feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

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Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to puc.datarequests@state.or.us.

/s/ Matt Muldoon, E-RFA, Manager Economics Analysis

Staff Initiator: Nadine Hanhan Nadine.hanhan@state.or.us (503) 931-0161

Oregon
Kate Brown, Governor

Public Utility Commission
3930 Fairview Industrial Dr SE
Salem, OR 97302-1166
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: 503-378-6600
Administrative Services
503-373-7394

July 2, 2020

DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 2000
PORTLAND, OR 97232
datarequest@pacificorp.com

RE:	Docket No.	OPUC Request Nos.	Response Due By
	UE 374	OPUC 734-749	July 9, 2020

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

Topic or Keyword: Transmission

DR 734 TO DR 736 ARE CONFIDENTIAL

737. Please see the Company's response to Staff DR 463, regarding the Goshen-Sugarmill-Rigby project. The Company states, "The Company has employed the use of interruptible rates with farmers, which enables the reduction of loads during certain peak periods when necessary, but participation in these programs is a partial driver for the project."

    a. Please further explain what is meant by "participation in these programs is a partial driver for the project."

738. In general, how does the Company determine contingency percentages for transmission projects?

739. Please see PAC/1000, Vail/11. For any projects in which the Company assigns contingency percentages for cost estimation, please explain what the basis is for arriving at these percentages?

740. Did the Company perform a 7-factor test on any of the projects in PAC/1000, Vail/11? If so, please provide the results of the 7-factor tests.

741. Has the Company performed a 7-factor test on any of the following transmission projects:
    a. The projects in Confidential Work paper Pro Forma Plant Additions CONF, tab 8.5.21 CONF, column A?
    b. The projects that make up Confidential Work paper Pro Forma Plant Additions CONF, tab 8.5.21 CONF, column A, Cell E61?
    c. If the answer to questions "a." or "b." is yes, please provide the data (e.g. one-line diagrams and other such documents) on which a 7-factor test was performed.

742. Please see Company's response to Staff DR 458. How did the Company determine what was situs and what was system allocated?

743. For the Goshen-Sugarmill Rigby project in PAC/1000, Vail/11, please provide all contracts signed to complete the project.

744. For the SW Wyoming Silver Creek project in PAC/1000, Vail/11, please provide all contracts signed to complete the project.

745. For all projects in Confidential Work paper Pro Forma Plant Additions CONF, tab 8.5.21 CONF, column A, please provide all contracts signed to complete the projects.

746. For all projects that make up Confidential Work paper Pro Forma Plant Additions CONF, tab 8.5.21 CONF, column A, Cell E61, please provide all contracts signed to complete the projects.

747. For each of the projects listed in Exhibit PAC/1000, Vail/11, please provide the following:
    a. One line diagram.
    b. Explanation on whether and how the project serves local need or whether it serves PacifiCorp's overall transmission network, and the basis for that conclusion.
    c. A system map that depicts the project in relation to the overall transmission network.

748. Please see the Company's response to Staff DR 475. The Company states, "The amount indicated in PAC/1000/Vail/11 was stated in error. The plant in-service amount for this project was $42.5 million which was the amount used in the preparation of the rate filing." Please confirm that the total cost of this project for which the Company seeks cost recovery is $42.5 million and not $42.8 as outlined in testimony?

749. Please confirm that the total cost of the NE Portland Upgrade project is $20.6 million and not $41.2 million as implied by PAC/1000, Vail/11.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.
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the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to puc.datarequests@state.or.us.

/s/ Matt Muldoon, E-RFA, Manager Economic Analysis

Staff Initiator: Nadine Hanhan nadine.hanhan@state.or.us (503) 931-0161

OPUC Data Request 151

For each transmission line and associated build for which the Company is asking for cost recovery in this case, do or will the contracts for construction both reduce as well as ratchet up or increase costs for build based on changes in the costs of each of a) steel, b) structural steel, c) copper and d) aluminum? If not please explain why not.

Response to OPUC Data Request 151

PacifiCorp's contracting approach on these major projects is risk averse. Market competition is used to reach qualified low cost contractors. The executed contracts limit upside price exposure and including provisions that benefit PacifiCorp in the event of price reductions on metal commodities.

OPUC Data Request 152

For each transmission line and associated build for which the Company is asking for cost recovery in this case, please explain each escalation in cost due to:

(a) a) different than expected hydrology,
(b) different than expected geology or rock hardness,
(c) different than expected elevation changes, and
(d) different than expected direction changes.

Response to OPUC Data Request 152

PacifiCorp's contracting approach on these major projects is risk averse. Market competition is used to reach qualified low cost contractors. The executed contracts include contractor subsurface risks (subparts (a), (b) and (c)). An unforeseen direction change (subpart (d)) would be covered under the unit rate structure of the contract as a change notice.

OPUC Data Request 226

Please refer to Confidential Workpaper Pro Forma Plant Additions_CONF, tab 8.5.21_CONF, column A.

(a) Please provide an itemized breakdown, including costs and in-service date, of all projects in Column A.

(b) Please provide a narrative description of the all the projects in cells A8 through A24.

(c) Were any of these projects acknowledged in an IRP? If so, please provide the difference in costs between what was projected in an IRP and what actual costs the Company is asking recovery for.

(d) Please provide any and all interconnection studies associated with these projects (e.g., System Impact Study, Feasibility Study, and Facilities Study).

Response to OPUC Data Request 226

(a) Please refer to the Confidential Workpaper Pro-Forma Plant Additions, tab 8.5.21 for a breakdown of costs and in-service dates per project.

(b) Please refer to Confidential Attachment OPUC 226-1 for narrative descriptions on projects in cells A8 through A24.

(c) No.

(d) Please refer to Confidential Attachment OPUC 226-2 which provides studies for the Oregon New Large Load Network Upgrades, and please refer to Attachment OPUC 226-3 which provides studies for Q0542 Pryor Mountain.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 374/PacifiCorp
May 19, 2020
OPUC Data Request 460

OPUC Data Request 460

Transmissio n
CONFIDENTIAL REQUEST - Plea se see Company response to Staff DR 150, Attachment labeled "Vantage Pom ona PCN 94008750 8-16-2018. df." The Com an states **CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

(a) Please explain these cost increases.

(b) Please provide an update as to the status of completion of this project.

(c) Is this project on track to be complete by May 2020 as indicated by PAC/l 000N ail/11?

(d) **[CONFIDENTIAL BEGINS]** [redacted] **ONFIDENTIAL ENDS].**

(e) **CONFIDENTIAL BEGINS]** [redacted] **CONFIDENTIAL ENDS].** If so, please provide documentation. If not, please explain why not.

(f) Please explain the discrepancy in fmal chan e order costs for **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL END S]**, and the cost as reque sted by PAC/IO00N ail/ 11.

(g) In your answer to a-d above, please include any internal memos, analytics, presentations, work papers, and communications justifying the cost changes.

Response to OPUC Data Request 460

(a) The cost increases are due to various unanticipated constrnction issues such as an increase in the number of rock drilling for foundations and holes for dirnct buried poles. Additionally, there were numerous weather impacts to construction schedules that could not be planned for or estimated ahead of the construction work , and the labor costs were significantly higher than n01mal due to west coast labor sh01tages. There were increased pe1mitting costs because of the much longer than expected timeframe to complete the federal National Environmental Policy Act (NEPA) process. All NEPA

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any pri\<il eged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

documentation are publicly available from the United States Bureau of Land Management (BLM) website at:

https://eplanning.blm.gov/epl-front-office/eplanning/planAndProjectSite.do?methodName=dispatchToPatternPage&currentPageId=83572

Bonneville Power Administration (BPA) determined a more detailed plan of development and scope of work were required after their review of the final design. The main driver of this was a change to the new line configuration into the Vantage substation from the original plan that was required to meet changes in the permitting requirements. The new scope included BPA's cost increases due to a larger dead end structure at the substation

(b) The line is constructed up to the last two spans connecting into the Vantage substation. Prior to starting the work to complete these spans an active falcon nesting site was discovered that stopped all work until the fledglings leave the nest. The construction of the line is expected to be completed by the end of June 2020.

(c) No the project is currently on track for a June 2020 completion.

(d) The Company was fully aware of the relevant sage grouse regulations which is fully evidenced by the amount of coordination and work effort applied to resolving the concerns related to the sage grouse population in the Yakima Valley.

The process for resolving the sage grouse related issues are clearly documented in the various federal requirements for developing and reviewing, for comparative purposes, alternate routes for the new transmission line. Sage grouse issues were one of many considerations the federal government, through the project lead agency (the BLM) was required to review prior to issuing their decision on the preferred route in the Environment Impact Statement and ultimately give the Notice to Proceed with construction of the line. The time frame to negotiate through these reviews for all issues was arduous and required multiple state and federal, as well as tribal, agency consultation all as required and therefore directed by the BLM.

(e) Yes, please refer to Attachment OPUC 460 which provides a copy of the interconnection agreement.

(f) Please refer to the Company's response to subpart (a) above.

(g) Please refer to Attachment OPUC 460 for a copy of the interconnection agreement. The documents provided with the Company's response to OPUC Data Request 150, specifically Confidential Attachment OPUC 150, are the communication of cost changes. Please also refer to the Company's confidential response to OPUC Data Request 470 for the investment appraisal documents associated with this project.

OPUC Data Request 529

Transmission
Please refer to Confidential Workpaper Pro Forma Plant Additions_CONF, tab 8.5.21_CONF, column A.

(a) For all projects listed in Column A, please provide all internal approval documents as listed on pages 5-8 in PacifiCorp's confidential Corporate Governance and Approvals Process (See Attach OPUC 174-1 CONF).

(b) In your answer, please also indicate which projects in Column A, if any, are associated with/correspond with the projects outlined in PAC/1000, Vail/11.

(c) In your answer, please include all individual projects that make up the dollar amount in cell E61.

Response to OPUC Data Request 529

(a) Please refer to Confidential Attachment OPUC 529.

(b) The following projects are outlined in PAC/100, Vail/11:
- Vantage-to-Pomona Heights 230 kilovolt (kV) line
- Goshen-to-Sugarmill-to-Rigby 161 kV transmission line

(c) Please refer to Confidential Attachment OPUC 225-1.

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OPUC Data Request 740

Transmission
Did the Company perform a 7-factor test on any of the projects in PAC/1000, Vail/11? If so, please provide the results of the 7-factor tests.

Response to OPUC Data Request 740

The Company did not perform 7-factor tests for any of the projects in PAC/1000. The projects are treated consistently with current usage and treatment of assets in PacifiCorp's Open Access Transmission Tariff.

OPUC Data Request 741

Transmission
Has the Company performed a 7-factor test on any of the following transmission projects:

a. The projects in Confidential Work paper Pro Forma Plant Additions CONF, tab 8.5.21 CONF, column A?
b. The projects that make up Confidential Work paper Pro Forma Plant Additions CONF, tab 8.5.21 CONF, column A, Cell E61?
c. If the answer to questions "a." or "b." is yes, please provide the data (e.g. one-line diagrams and other such documents) on which a 7-factor test was performed.

Response to OPUC Data Request 741

The Company has not performed 7-factor tests for any of the listed projects. The projects are treated consistently with current usage and treatment of assets in PacifiCorp's Open Access Transmission Tariff.

OPUC Data Request 742

Transmission
Please see Company's response to Staff DR 458. How did the Company determine what was situs and what was system allocated?

Response to OPUC Data Request 742

In accordance with the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol, distribution assets are situs assigned to the state where they are located and transmission assets are system allocated.

OPUC Data Request 745

For all projects in Confidential Work paper Pro Forma Plant Additions CONF, tab 8.5.21 CONF, column A, please provide all contracts signed to complete the projects.

Response to OPUC Data Request 745

PacifiCorp objects to this request as overly burdensome. Without waiving these objections, the Company responds as follows:

Please refer to Confidential Attachment OPUC 745 for a list of projects from tab "8.5.21 CONF," column A, of the referenced workpaper. The attachment identifies contracts gathered to date that are responsive to this request. Please note that several line items are blanket projects that provide the means of allocating capital funds for a category of work. These blanket projects may include up to 200 individual work orders. Individual contracts have not been gathered for these work orders. See the "Notes" column of the attachment for a brief summary of the purpose of the blanket projects.

Disclosure of all of the contracts, if released in bulk as requested here, would allow vendors to understand standard provisions of the agreements. Such a release would put the Company at a competitive disadvantage in the market, which would negatively impact customers. Therefore, the Company considers the contracts to be commercially sensitive and highly confidential. If individual contracts are needed for testimony or exhibits, PacifiCorp will agree to treatment of the individual agreements as either confidential or public, depending on the individual terms of the agreement and number of contracts requested. The Company request special handling. Please contact Matt McVee at (503)-813-5585 to make arrangements for review.

The Company will supplement this response as additional responsive materials are gathered.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Highly Confidential information is designated as Highly Protected Information under the modified protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 746

For all projects that make up Confidential Work paper Pro Forma Plant Additions CONF, tab 8.5.21 CONF, column A, Cell E61, please provide all contracts signed to complete the projects.

Response to OPUC Data Request 746

PacifiCorp objects to this request overly burdensome. Without waiving these objections, the Company responds as follows:

Please refer to Confidential Attachment OPUC 746 for a list of projects from tab "8.5.21 CONF," column A, Cell E61, of the referenced workpaper. The attachment identifies contracts gathered to date that are responsive to this request. Please note that several line items are blanket projects that provide the means of allocating capital funds for a category of work. These blanket projects may include up to 200 individual work orders. Individual contracts have not been gathered for these work orders.

Disclosure of all of the contracts, if released in bulk as requested here, would allow vendors to understand standard provisions of the agreements. Such a release would put the Company at a competitive disadvantage in the market, which would negatively impact customers. Therefore, the Company considers the contracts to be commercially sensitive and highly confidential. If individual contracts are needed for testimony or exhibits, PacifiCorp will agree to treatment of the individual agreements as either confidential or public, depending on the individual terms of the agreement and number of contracts requested. The Company request special handling. Please contact Matt McVee at (503)-813-5585 to make arrangements for review.

The Company will supplement this response as additional responsive materials are gathered.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Highly Confidential information is designated as Highly Protected Information under the modified protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 747

Transmission
For each of the projects listed in Exhibit PAC/1000, Vail/11, please provide the following:

a. One line diagram.
b. Explanation on whether and how the project serves local need or whether it serves PacifiCorp's overall transmission network, and the basis for that conclusion.
c. A system map that depicts the project in relation to the overall transmission network.

Response to OPUC Data Request 747

a. The one-lines and system maps for each project were previously provided as exhibits to Mr. Vail's direct testimony.

b. While recognizing that each project that benefits the overall transmission system may also provide benefits to customers in the local vicinity of those transmission facilities, the primary driver of each project is listed in the table below.

c. Please refer to the Company's response to subpart (a) above.

Project	Serves Local Need / Overall	Comments
Aeolus to Bridger/Anticline 500 kV line	Transmission	Supports the Company's short- and long-term energy demands for serving customers across the entire PacifiCorp system, and will strengthen the overall reliability of the existing Wyoming transmission system and therefore PacifiCorp's entire transmission system.
Q707 TB Flats 1	Transmission	Required to serve customer Generation Interconnection request
Q712 Cedar Springs Wind 1	Transmission	Required to serve customer Generation Interconnection request
Wallula to McNary 230 kV New Transmission Line	Transmission	Required to serve customer Transmission Service Request. Enhances reliability in area 230 kV transmission system.
Snow Goose 500-230 kV New Substation Project	Transmission	Mitigates NERC TPL-001-4 transmission system performance criteria deficiencies. Reinforces southern Oregon 500 kV and 230 kV transmission systems.
Vantage to Pomona Heights 230 kV New Transmission Line Project	Transmission	Mitigates NERC TPL-001-4 transmission system performance criteria deficiencies. Reinforces Yakima, Washington area 230 kV and 115 kV transmission systems.
Goshen-Sugarmill-Rigby 161kV Transmission Line Project	Transmission	Alleviates operational limitations and reliability impacts necessary to meet NERC TPL-001-4 transmission system performance criteria. Reinforces Goshen, Idaho area 161 kV transmission system.

Project	Serves Local Need / Overall	Comments
Sigurd-Red Butte 345kV Line	Transmission	Alleviates operational limitations and reliability impacts necessary to meet NERC TPL-001-4 transmission system performance criteria and strengthens backbone 345 kV main grid transmission system in central and southern Utah.
NE Portland Transmission Upgrade	Transmission	Mitigates NERC TPL-001-4 transmission system performance criteria deficiencies. Reinforces Portland, Oregon area 115 kV and 69 kV transmission systems.
Southwest WY Silver Creek 138kV Ln- (In-Service)	Transmission	Alleviates operational limitations and reliability impacts necessary to meet NERC TPL-001-4 transmission system performance criteria. Reinforces Park City, Utah area 138 kV transmission systems.
Threemile Canyon Farm 2,500 HP Increase- (In-Service)	Local Need	Required to serve customer load interconnection request on local 34.5 kV distribution system.

OPUC Data Request 748

Transmission
Please see the Company's response to Staff DR 475. The Company states, "The amount indicated in PAC/1000/Vail/11 was stated in error. The plant in-service amount for this project was $42.5 million which was the amount used in the preparation of the rate filing." Please confirm that the total cost of this project for which the Company seeks cost recovery is $42.5 million and not $42.8 as outlined in testimony?

Response to OPUC Data Request 748

The Company is seeking cost recovery of $42.5 million for the Snow Goose 500-230 kV New Substation Project.

CASE: UE 374
WITNESSES: NADINE HANHAN-YASSIR RASHID-MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2102

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Staff Exhibit 2102 is confidential subject to Protective Order No. 20-040.

CASE: UE 374
WITNESSES: NADINE HANHAN-YASSIR RASHID-MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2103

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Staff Exhibit 2103 is confidential subject to Protective Order No. 20-040.

CASE: UE 374
WITNESSES: NADINE HANHAN-YASSIR RASHID-MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2104

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Staff Exhibit 2104 is confidential subject to Protective Order No. 20-040.

CASE: UE 374
WITNESSES: NADINE HANHAN-YASSIR RASHID-MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2105

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Staff Exhibit 2105 is confidential subject to Protective Order No. 20-040.

CASE: UE 374
WITNESSES: NADINE HANHAN-YASSIR RASHID-MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2106

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Staff Exhibit 2106 is confidential subject to Protective Order No. 20-040.

CASE: UE 374
WITNESSES: NADINE HANHAN-YASSIR RASHID-MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2107

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Staff Exhibit 2107 is confidential subject to Protective Order No. 20-040.

CASE: UE 374
WITNESSES: NADINE HANHAN-YASSIR RASHID-MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2108

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Staff Exhibit 2108 is confidential subject to Protective Order No. 20-040.

CASE: UE 374
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2200

Rebuttal Testimony

July 24, 2020

Q. Please state your name, occupation, and business address.

A. My name is Rose Anderson. I am a Senior Economist employed in the Resource Planning Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1501.

Q. What is the purpose of your testimony?

A. I present Staff's reply to PacifiCorp's Reply Testimony regarding:

1. Oregon coal Exit Orders and Exit Dates, as defined in the 2020 Multi-State Protocol Sections 3 and 4 adopted by the Commission in Order No. 20-024, for PacifiCorp's Hunter, Huntington, and Wyodak coal units; and
2. PacifiCorp's proposal for a Generation Plant Removal Adjustment tariff.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Coal Exit Orders and Exit Dates 2
Issue 2. Generation Plant Removal Adjustment 8

ISSUE 1. COAL EXIT ORDERS AND EXIT DATES

Q. Please Summarize your Opening Testimony regarding coal exit orders and exit dates.

A. My Opening Testimony recommends the Commission issue Exit Orders for coal units as recommended by PacifiCorp, except for the units at Hunter, Huntington, and Wyodak. While Staff agreed in the 2020 Protocol to support the issuance of Exit Orders for units at these three plants by December 31, 2023, the issuance of Exit Orders in the current General Rate Case would be much earlier and would take away some options and potential cost savings from Oregon ratepayers.

Q. Please summarize PacifiCorp's Rebuttal Testimony regarding coal exit dates and exit orders.

A. Mr. Wilding's testimony implies that Staff has diverged from what parties agreed to in the MSP settlement agreement. Mr. Wilding states that Staff has not made an argument which represents "changed or unforeseen circumstances that would justify positions contrary to the commitments… made under the 2020 Protocol."[1] Mr. Wilding also states that there are benefits to customers from issuing Exit Orders at this time, including "certainty as to when coal-fired resources are removed from rates," and that the Company will benefit from the certainty of Exit Orders issued now.[2]

Q. Does your testimony depart from the 2020 Protocol?

[1] PAC/2000, Wilding/31.
[2] PAC/2000, Wilding/32.

A. No. This is not an accurate representation of Staff's position. In the 2020 Protocol, parties agreed to support the issuance of Exit Orders for units at Hunter, Huntington, and Wyodak by December 31, 2023. Staff continues to support the issuance of these Exit Orders by December 31, 2023. Staff does not, however, support the early issuance of these Exit Orders in the current General Rate Case. The 2020 Protocol specifies that, "A Commission may issue an Exit Order specifying an Exit Date in a proceeding for approval of this Agreement, a depreciation docket, a rate case, or any other appropriate proceeding." Therefore, the Commission will have other opportunities to issue Exit Orders closer to the December 31, 2023 date, which Staff supports as a reasonable date to provide notice to other parties regarding Oregon's intentions to exit units at Hunter, Huntington, and Wyodak.

Q. Has PacifiCorp provided evidence of any benefits to Oregon ratepayers that would be lost absent the issuance of exit orders for Hunter, Huntington and Wyodak?

A. No. Mr. Wilding's testimony states that Oregon customers will "receive certainty as to when coal-fired resources are removed from rates." [3] However, it is unclear how this certainty might benefit ratepayers, while it is clear that early issuance of Exit Orders will reduce flexibility to potentially achieve better outcomes for Oregon ratepayers.

Q. Is PacifiCorp's position in this case consistent with the 2020 Protocol?

[3] PAC/2000, Wilding/32.

A. No. PacifiCorp advocates for the Commission to take early action in issuing Exit Orders for Hunter, Huntington and Wyodak, as is clear from the plain language of the 2020 Protocol. Staff is disappointed and concerned that at the first opportunity to implement the MSP agreement in Oregon rates, the Company is advocating for positions that are not only contrary to the agreement, but potentially detrimental to Oregon ratepayers. As explicitly stated in Section 4.1.2., "The Parties, representing diverse and varied interests, have worked in good faith to create a process that allows for States to pursue differing resource portfolios in the future, including decisions to transmission out of coal-fueled Interim Period Resources while mitigating resulting effects to the Company and other States." Further, the Oregon parties, including Staff, negotiated the 2020 Protocol as an integrated document, and evaluated the risks and benefits of the agreement based on the whole agreement, including areas that remain unsettled in the Framework Issues section.[4] Advocating in this General Rate Case for different treatment of the Implemented Issues is inappropriate and erodes the value of the 2020 Protocol negotiated by all parties to the agreement.

Q. What do ratepayers stand to lose by the Issuance of Exit Orders for Hunter, Huntington, and Wyodak in this General Rate Case?

A. The effects of PacifiCorp's proposal to ratepayers is unknown, because it affects other provisions of the future cost allocations that have not been resolved by the parties to the MSP process, nor by any state commission.

[4] Framework Issues are discussed in the 2020 Protocol, Section 6.

Specifically, the issuance of Exit Orders is meaningful and used for more purposes than simply providing notice to other parties. Section 4.1.2 of the 2020 Protocol provides that "An Exit Order establishes the Exit Date that PacifiCorp will use to propose the allocation of Decommissioning Costs, allocation of capital additions costs, and any other associated costs related to the exit from a coal-fueled Interim Period Resource as outlined in the 2020 Protocol." While decommissioning cost allocations have been fully negotiated and known pursuant to Section 4.3, allocation of capital additions costs and other issues are not settled by the 2020 Protocol and remain open areas of negotiation currently.

Thus, the Exit Order triggers additional process that is not yet settled in the Framework agreement. Issuing an Exit Order for these units early will eliminate the possibility for ratepayers and other parties to benefit from any new information that could come to light between this rate case and the end of 2023. And as stated above, this could create additional costs for Oregon customers.

Additionally, if Exit Orders are issued in this General Rate Case, the December 31, 2029, Exit Dates for these units will become a more powerful focal point of discussions of potential economic retirements. This could influence any early retirement decisions of plant owners or operators. Issuing Exit Orders early in this General Rate Case could unnecessarily influence conversations around retirement dates, and should be avoided.

Staff is concerned that issuing exit orders prematurely may also chill the opportunity for early economic retirements at these units.

Q. Does Staff find that the Commission's delay in issuing Exit Orders for Hunter, Huntington, and Wyodak would be unfair or inappropriate to other states under the 2020 Protocol?

A. No. PacifiCorp's argument that other states will be provided with more notice if the Commission issues exit orders for these units now is groundless. Per the terms of the 2020 Protocol, other states know with certainty that Oregon will, under any and all circumstances, be out of Hunter, Huntington and Wyodak no later than December 31, 2029. Further, pursuant to Section 4.1.2, the parties agreed to attempt to provide at least four years of notice from the issuance date of the Exit Order to the Exit Date. Issuing an Exit Order for these plants with nearly nine years advance notice only serves to potentially limit Oregon's flexibility in these resources and provide the potential for the allocation of additional costs to Oregon.

Q. In summary, what does Staff recommend regarding Exit Orders for Hunter, Huntington, and Wyodak?

A. The Commission should not issue Exit Orders for these units in the current General Rate Case. Instead, the Commission should wait to see if new information becomes available and issue Exit Orders for units at Hunter, Huntington, and Wyodak by December 31, 2023, as was negotiated by the parties to the 2020 Protocol including PacifiCorp. This will allow PacifiCorp, OPUC Staff, and other parties more time to consider cost allocation and

1 economic retirement dates for these units without being influenced by the
2 existence of Exit Orders at this early date.

ISSUE 2. GENERATION PLANT REMOVAL ADJUSTMENT

Q. Please summarize Staff's recommendation regarding the proposed Generation Plant Removal Adjustment (GPRA) tariff.

A. Staff recommends that to ensure coal plant costs are removed from Oregon rates in a timely manner, coal plant capital should be removed from base rates now and placed into a separate Automatic Adjustment Clause (AAC), where the amount of undepreciated capital can be updated on an annual basis to reflect depreciation. This AAC wouldresult in customer benefits from reduced regulatory lag, a more accurate return on PacifiCorp's investment, and a more timely prudence review of future capital investments. Staff's recommendation differs from PacifiCorp's proposed GPRA in that it seeks to remove the coal plants from rate base at the conclusion of this rate case with rates updated annually, instead of later at the time of Oregon's Exit Date for each unit with rates updated only during general rate cases.

Additionally, Staff supports PacifiCorp's recommendation to remove Cholla 4 undepreciated capital costs from the proposed GPRA and offset them with tax benefits, resulting in amortization by December 31, 2020.

Staff does not recommend approval of the Generation Plant Removal Adjustment GPRA Tariff.

Q. Please summarize the Company's Reply Testimony regarding the proposed Generation Plant Removal Adjustment (GPRA) tariff.

A. In Reply Testimony, Mr. Wilding disagrees with Staff's concerns about the GPRA. In response to Staff's concern that the GPRA is unnecessarily broad, Mr. Wilding argues that the GPRA is narrowly designed to remove coal resources from Oregon rates. Mr. Wilding's testimony also argues that including a depreciation update in the GPRA would be "beyond the limited scope of the mechanism, and would defeat its purpose as a streamlined mechanism to remove coal plants from rates."[5] Finally, Mr. Wilding states that it is not appropriate to use depreciation expense as an offset to future investment.

Q. Does Staff's proposal seek to use depreciation expense as an offset to future investment?

A. No. Staff's proposal will allow the utility to recover both the return of and return on its investment. Staff's proposal did not dictate that depreciation expense would be used to offset future investment. To address Mr. Wilding's concern however, Staff would like to clarify its position that the Company should be allowed to ask for a prudence review of any additional capital costs associated with the coal units as part of its annual filing. This process would allow the Company to recover appropriately allocated, prudent capital investments between general rate case proceedings. This would also allow the Commission to ensure that any capital investments made are appropriately allocated to Oregon and are prudent in a timely manner.

Q. Does Staff still believe that the GPRA is unnecessarily broad?

[5] PAC/2000, Wilding/43.

A. Yes. Despite PacifiCorp's claims in testimony, the tariff language of the GPRA as proposed does not specify that it applies only to coal plants. Under the language of the tariff, therefore, PacifiCorp could attempt in the future to use the GPRA for other retiring plants. While Mr. Wilding's testimony stated that the GPRA is meant to remove coal-fired resources from Oregon rates, PacifiCorp has not suggested any changes to the language of its proposed GPRA tariff to ensure that the mechanism would only apply to coal plants. Staff finds that if the Commission adopts the Company's GPRA, it should direct the Company to update the language to clarify that it applies to coal-fueled resources only.

Q. Is Staff's proposed AAC unnecessarily complicated?

A. No. Staff's proposal will consist of an Automatic Adjustment Clause with annual updates, as well as a prudence review for any requested future capital investments. These are common procedures for the Company and the Commission, and they should not cause undue burden.

<u>Staff recommends Cholla 4 cost recovery through a tax benefits offset.</u>

Q. Does PacifiCorp continue to recommend recovery of costs associated with Cholla 4 through the GPRA its Reply Testimony?

1 A. No. PacifiCorp now recommends using tax benefits to offset the Cholla 4
2 unrecovered plant and closure costs, resulting in the amortization of all
3 remaining Cholla 4 unrecovered plant balances as of December 31, 2020.[6]
4 **Q. Please explain Staff's recommendation regarding Cholla 4 cost**
5 **recovery.**
6 A. Staff recommends the Commission accept PacifiCorp's proposal to use tax
7 benefits as an offset to the Cholla 4 unrecovered plant balance. This proposal
8 will allow timely recovery of undepreciated plant, while remaining consistent
9 with Commission precedent for plant that is no longer used and useful.
10 However, Staff requests that in Surrebuttal Testimony, PacifiCorp explain
11 whether it is requesting to include decommissioning costs in the 'closure costs'
12 which it is seeking to offset with tax benefits.
13 **Q. Does this conclude your testimony?**
14 A. Yes.

[6] PAC/3100, McCoy/34.

CASE: UE 374
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2300

Rebuttal Testimony

July 24, 2020

Q. Please state your name, occupation, and business address.

A. My name is Sabrinna Soldavini. I am a Senior Regulatory Analyst employed in the Energy, Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Have you already provided testimony in this case?

A. Yes, I previously provided testimony in this case in Exhibit Staff/700.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to PacifiCorp and other parties' positions on the issues of environmental compliance investments at Jim Bridger, Hayden, Hunter and Craig, other revenue, reliability coordinator fees, and custody fees.

Q. Please provide a summary table of the adjustments proposed in your testimony.

A. The following table provides a summary of my recommended adjustments.

Adjustment	Reference Page	OR Allocated Amount	Type of Adjustment
Jim Bridger SCR Management	Soldavini/56-57	[redacted]	Rate Base
Jim Bridger SCR Depreciation	Soldavini/56-57	[redacted]	Rate Base
Hayden SCR Depreciation	Soldavini/73-74	[redacted]	Rate Base
Hunter Low NOx and Baghouse Depreciation	Soldavini/80-81	[redacted]	Rate Base
Craig SCR Depreciation	Soldavini/83-84	[redacted]	Rate Base
Reliability Coordinator Fee	Soldavini/87	($575,553)	Expense
Custody Fees	Soldavini/90	($71,527)	Expense

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Staff/2301, PacifiCorp Response to Staff Data Requests
Staff/2302, PacifiCorp Response to Other Parties' Data Requests
Staff/2303, Staff SCR Analysis

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Jim Bridger SCRs 3
Issue 2, Hayden SCRs 61
Issue 3, Hunter Unit 1 Low NOx Burners and Baghouse 75
Issue 4, Craig Unit 2 SCR 82
Issue 5, Other Revenue 85
Issue 6, Reliability Coordinator Fee 87
Issue 7, Custody Fees 89

1 **ISSUE 1, JIM BRIDGER SCRS**

2 **Q. Please summarize this section of your testimony.**

3 A. In this case, PacifiCorp is seeking to recover the costs of emissions control
4 retrofit projects at Jim Bridger Units 3 and 4 associated with emissions control
5 guidelines in Wyoming. In May 2013, the decision was made to move forward
6 with the installation of Selective Catalytic Reduction (SCR) Systems for Jim
7 Bridger Units 3 and 4. These projects were subsequently completed in
8 November 2015 and November 2016, respectively.

9 Some parties' Opening Testimony, including the Alliance of Western Energy
10 Consumers (AWEC), Oregon Citizens' Utility Board (CUB), Sierra Club, and
11 Staff raised issues concerning the Company's decision making process and
12 ultimately, the prudence of these investments. This section of my testimony will
13 outline the parties' positions, PacifiCorp's reply, and Staff's proposed
14 recommendations based on its analysis and response to other parties'
15 arguments.

16 **Q. What is Staff's recommendation?**

17 A. As described in the sections to follow, Staff maintains that the Company
18 appears to have acted prudently in December of 2013, when it issued its final
19 notice to proceed (FNTP) with the installation of Selective Catalytic Reduction
20 (SCR) systems at Jim Bridger Units 3 and 4 to comply with what Staff believes
21 were reasonably assumed to be enforceable State and Federal guidelines.
22 However, Staff continues to believe that the Company's analysis leading up to
23 its issuing its FNTP was deficient.

Based on new information, Staff first recommends the Commission find that the initial level of cost recovery sought by the Company applies an incorrect depreciable life, and reduce the Oregon allocated net book value of the Jim Bridger 3 and 4 SCRs by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This level of recovery properly accounts for the level of regulatory lag that these investments should be subject to given Oregon's depreciable life for Jim Bridger of 2025.[1]

Additionally, Staff recommends that based on Staff's recommended Oregon allocated net book value by the rate effective data, the Commission:

1. Apply an additional 10 percent management disallowance to the Oregon allocated gross book value, equal to approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**; OR
2. Allow the full undepreciated cost of the investments into rates (based on Staff's recommended Oregon allocated net book value), but not allow the Company to collect a rate of return on the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** associated with the SCRs.

Q. Did any other parties address the issue of the Jim Bridger SCRs in Opening Testimony?

A. Yes. AWEC, CUB, and Sierra Club, all addressed the issue of environmental compliance costs at PacifiCorp's coal plants. All three parties recommended

[1] Docket No. UM 1647, Order No. 13-347.

that the Commission find the Company's request to recover SCR costs at Jim Bridger Unit 3 and Unit 4 imprudent, for various reasons as discussed later in my testimony.

Q. How has the Company responded to Staff and intervenors recommendations?

A. PacifiCorp maintains that its investment decisions were prudent and recommends the Commission reject parties' recommendations to partially or fully disallow cost recovery.

I. Parties' Opening Testimony Positions and PacifiCorp's Response

Q. Please summarize Sierra Club's Opening Testimony position.

A. In its Opening Testimony, Sierra Club provided 10 reasons why PacifiCorp's decision to install SCR equipment at Jim Bridger Units 3 and 4 was imprudent.[2] Each will be discussed below. Summarily, Sierra Club asserts that the Company "understood that its election to move forward with the SCRs at Jim Bridger 3 and 4 was premature, and had degraded in value from the time the Company first proposed the projects to effectively no economic value to ratepayers at the time."[3]

Sierra Club recommends that the Commission either, require the Company to assess the costs of having converted to gas in 2015 and 2016 or having delayed repowering until 2019, and assess damages as the difference between actual and theoretical capital plus operational costs incurred from 2013 to the

[2] Sierra Club/100, Fisher/4-6.
[3] Sierra Club/100, Fisher/4.

present day; or, identify the costs of the SCRs as the imprudent and disallow the costs of the SCRs in full.[4]

Q. Please summarize CUB's Opening Testimony position on this issue.

A. CUB also recommends the Commission find PacifiCorp's SCR investment at Jim Bridger Units 3 and 4 imprudent, stating that these investments were never acknowledged in the Commission's Integrated Resource (IRP) process, and that the Company should have avoided these costs by committing to close the units at a future date.[5] CUB further notes its belief that the Company's analysis was seriously flawed as it failed to consider the least cost alternatives to the SCRs, failed to analyze the investment in an IRP prior to committing, failed to consider the flexibility that is allowed under the Regional Haze Rules, failed to consider the useful life of the plant, and failed to heed ample warning from the Oregon Commission that it should be considering coal plant retirement.[6]

Q. Please summarize AWEC's Opening Testimony position on this issue.

A. Finally, in its Opening Testimony, AWEC recommends the Commission find PacifiCorp's SCR investment at Jim Bridger Units 3 and 4 imprudent, basing its decision on the assertion that PacifiCorp "failed to place appropriate weight on important factors and variables that were known to PacifiCorp at the time the investments were made."[7] These factors include Oregon social and political landscape, risk related to coal costs, risk related to market sales, potential

[4] Sierra Club/100, Fisher/64-65.
[5] CUB/100, Jenks/9.
[6] CUB/100, Jenks/10-11.
[7] AWEC/300, Kaufman/33.

1 economies associated with alternative compliance, and the potential value of
2 water rights.[8]

3 **Q. How has the Company responded to Staff's and intervenors'**
4 **recommendations?**

5 A. PacifiCorp maintains that its investment decisions were prudent and
6 recommends the Commission reject parties' recommendations to partially or
7 fully disallow cost recovery, and continues to recommend the Commission
8 allow full cost recovery of its environmental compliance investments.

9 In its Reply Testimony, PacifiCorp utilizes three separate witnesses: Mr. Link,
10 Mr. Ralston, and Mr. Owen to address the parties' concerns and lay out the
11 Company's argument to each point raised by Staff and Intervenors. In the
12 sections that follow, I will detail parties' positions as to why the Company's
13 analysis leading up to its decision to install SCRs at Jim Bridger Units 3 and 4
14 was deficient, describe the Company's response, and Staff's rebuttal.

15 **Q. Did PacifiCorp directly address Staff's testimony in its Reply**
16 **Testimony?**

17 A. Yes. PacifiCorp notes that it disagrees with Staff's assertion that it should have
18 analyzed more alternative compliance scenarios, and that Staff's conclusion
19 that the Company should have analyzed potential transmission system benefits
20 associated with retiring Units 3 and 4 is an unfair criticism.[9] The Company also
21 states that Staff mischaracterizes the Company's analysis by claiming that its

[8] *Ibid.*
[9] PAC/2300, Link/16.

1 analysis generally followed along the same lines as the coal analysis in Docket
2 No. UE 246.[10] The Company's reply and Staff's rebuttal will be discussed in the
3 sections below.

4 *Alternative Compliance Options Assessment*

5 **Q. What alternative compliance scenarios did the Company analyze?**

6 A. As described by the Company, it analyzed three different scenarios: installing
7 the SCRs in 2015 and 2016, retiring Units 3 and 4 in December 2020 and
8 2021, respectively; and conversion of Units 3 and 4 to natural gas in 2016 and
9 2017 respectively.[11] The Company then implies that "Staff also acknowledges
10 that the Company analyzed a fourth alternative – retiring Units 3 and 4 in 2022
11 and 2023, respectively."[12]

12 However, this fourth compliance scenario was not analyzed until after Staff
13 requested PacifiCorp perform this analysis during the Company's 2013 IRP,
14 and was not completed until after the Company made the decision to proceed
15 with the SCRS, thus Staff disagrees with the Company's attempt to frame
16 Staff's recognition that the Company performed such an analysis as evidence
17 that the Company analyzed this compliance scenario before making its
18 decision to proceed with the SCRs – this is simply misleading.

19 In fact, the next paragraph of Staff's Opening Testimony states "as pointed
20 out by the Commission in Order No. 14-252, Staff was able to demonstrate
21 from its additional requests related to the exploration of just one alternative

[10] PAC/2300, Link/18.
[11] PAC/2300, Link/13.
[12] *Ibid.*

compliance scenario, that lower cost alternatives could in fact exist"[13] leading to the conclusion that had the Company explored additional compliance options prior to the filing of its 2013 IRP, "a more comprehensive set of analysis could have been presented to the Commission."[14]

Q. Do any other parties assert that PacifiCorp's analysis was deficient in the number of alternative compliance options considered?

A. Yes. AWEC, CUB, and Sierra Club all take issue with the number of alternative compliance options sufficiently explored by the Company before issuing its FNTP in December 2013.

Q. Please elaborate.

A. CUB states that the Company failed to consider the flexibility under the Regional Haze Rule, which allowed a plant's owner to reduce the plant's useful life "which reduces the cost effectiveness of pollution control," and may have rendered the SCR no longer cost effective, and allowed for an alternative, less costly, form of compliance. [15]

CUB points out that the Company should have known this was an alternate compliance option available to it as Portland General Electric (PGE) made a substantially similar decision with regard to its Boardman plant in 2009/2010, allowing it to a avoid a large capital investment.[16] Staff notes that Sierra Club makes a similar claim, stating that this should have been clear to PacifiCorp in

[13] Staff/700, Soldavini/46.
[14] *Ibid.*
[15] CUB/100, Jenks/12.
[16] *Ibid*.

part because organizations such as CUB "strove to make it quite clear to PacifiCorp that this type of alternative compliance should be reviewed by the Company. In both opening comments, and then reiterated in final comments on PacifiCorp's 2011 IRP, CUB explicitly raised this alternative compliance opportunity."[17]

Q. Do parties identify how PacifiCorp should have utilized this knowledge in its analysis?

A. Yes. CUB asserts that the analysis should have looked at avoiding the SCR investment by ending the useful life of Bridger Units 3 and 4 in 2023 and 2024, or, at converting the plants to natural gas in 2024 and 2025, respectively.[18] CUB states that, "PacifiCorp limited the benefit of reducing the plant life by choosing end-of-life dates that were too soon therefore limiting the benefit of reducing the life of the useful life."[19] AWEC argues that PacifiCorp should have analyzed a scenario that assumed retirement for units 3 and 4 in 2024 and 2025, respectively.[20]

Q. Why did PacifiCorp not explore the referenced alternatives?

A. PacifiCorp states that "those were not realistic compliance scenarios given the time constraints applicable to Units 3 and 4,"[21] and suggests that even if modeling showed those were lower cost options, the modeling would be irrelevant as it could not achieve those outcomes in the real world.

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[17] Sierra Club/100, Fisher/29-30.
[18] CUB/100, Jenks/14.
[19] *Ibid*.
[20] AWEC/300, Kaufman/38.
[21] PAC/2300, Link/15.

1 **Q. Do CUB or AWEC make any other claims with respect to the**
2 **Company's alternative compliance analysis?**
3 A. Yes. Both parties take issue with PacifiCorp's analysis assuming operation of
4 Jim Bridger 3 and 4 until 2037, inconsistent with the Oregon depreciable life of
5 2025. CUB's notes that "if the Company had used the Oregon depreciable life it
6 is likely the SCR would not have been cost effective, and even more
7 importantly,...the SCR would not have been required.[22]
8 AWEC performs its own analysis, which it claims shows that had the
9 Company used the 2025 depreciable life, the "$174 million dollar benefit from
10 the SCR investment becomes a $441 million dollar loss" exceeding the benefit
11 in seven of nine scenarios analyzed in the IRP as shown below.[23]
12 **[BEGIN CONFIDENTIAL]**

13
14 **[END CONFIDENTIAL]**

[22] CUB/100, Jenks/17.
[23] AWEC/300, Kaufman/35.

1 **Q. How does the Company respond?**

2 A. PacifiCorp rejects both AWEC and CUB's claims regarding the 2025
3 depreciable life. The Company notes that at the time of the analysis it was not
4 contemplated that a coal plant would be removed from Oregon rates at the end
5 of its depreciable life, which is why it was not relevant in the 2013 analysis. The
6 Company also states that is has calculated the impact of using a 2025
7 depreciable life, while assuming that the Jim Bridger plant continues operating
8 beyond 2025 and that projected run-rate operating costs beyond 2025 treated
9 as an expense which the Company suggest is consistent with analysis prior to
10 the passage of Senate Bill 1547. The Company states that based on the
11 shortened depreciable life, SCRs remain favorable to gas conversion with a
12 present value of revenue requirement differential (PVRR(d)) of **[BEGIN**
13 **CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a system basis, and
14 when compared to only the SCR compliance scenario, the PVRR(d) benefits of
15 the SCR alternative are **[BEGIN CONFIDENTIAL]** [redacted] **[END**
16 **CONFIDENTIAL]** on a system basis.[24]

17 **Q. Does the Company offer any other support as to why analyzing the**
18 **three compliance options performed was suitable in this instance?**

19 A. Yes. The Company states that the analysis it did perform was reasonable given
20 the deadlines imposed upon it, and the significant amount of time (roughly two-
21 and-a-half years) needed to install SCR or convert Unit 3 to natural gas to meet
22 the 2015 compliance deadline. The Company notes that there was insufficient

[24] PAC/2300, Link/31-32.

time to re-open negotiations and push for a compliance option that would allow it to retire the units at a later date and had it assumed that it could delay SCR installation and that assumption turned out wrong, the Company would have insufficient time to install the SCRs or convert the units to gas.[25]

Q. How does PacifiCorp respond to Staff's claim that it should have considered the transmission benefits associated with retiring Jim Bridger Units 3 and 4?

A. The Company refutes Staff's claim that it should have considered the effects of potential transmission system benefits associated with retiring Units 3 and 4, noting that Sierra Club raised this issue in the Utah and Wyoming pre-approval cases. PacifiCorp states that in response to Sierra Club's concern, the Company conducted a sensitivity study that removed the Energy Gateway transmission investments and Wyoming wind resources that were able to interconnect because of Energy Gateway from both the SCR and gas conversion alternative model runs, which showed a PVRR(d) of $230 million favorable to the SCR.[26]

Staff appreciates the Company pointing this out, and conceded that it appears the Company did explore transmission, generally, but notes that the Company is not saying that it analyzed the effect of retirement. Staff assumes this is the result of the Company only analyzing the one retirement option. However, the premise of this point as raised by Staff in the 2013 IRP and in

[25] PAC/2300, Link/14.
[26] PAC/2300, Link/16-17.

1 Opening Testimony is that had this transmission been considered in the model
2 *before* PacifiCorp's determination that retirement was not the least cost option,
3 the result may have been different.

4 **Q. What is Staff's conclusion regarding PacifiCorp's analysis of**
5 **alternative compliance options?**

6 A. Staff's conclusion remains the same as it did in its Opening Testimony. Staff
7 believes that the Company failed to consider a sufficient number of alternatives
8 given the knowledge it had leading up to its decision to move forward with the
9 SCR investment at Jim Bridger Units 3 and 4.

10 Staff's position is strengthened by the testimony of AWEC, CUB, and Sierra
11 Club. Staff agrees with CUB and Sierra Club, that PGE's alternative compliance
12 strategy at its Boardman plant, should have led the Company to seriously
13 consider this possibility for Jim Bridger. Staff does not agree with the Company
14 that exploring one option for retirement before making the decision to proceed
15 with the SCR is evidence of such serious consideration.

16 Staff rejects the Company's argument that it did not need to model alternative
17 retirement dates, such as those suggested by CUB, AWEC, and Staff because
18 they were not realistic at the time. Staff agrees that by the time the 2013 IRP
19 was filed in Oregon, it may have been unlikely that such alternatives could be
20 achieved, but Staff cannot agree that had these options been explored before
21 the Company issued its LNTP, or while it was before the Wyoming and Utah
22 Commissions seeking pre-approval of the SCRs, that these alternative
23 compliance options were not realistic.

1 *2013 IRP*

2 **Q. Please summarize the 2013 IRP's relevance in this docket.**

3 A. This issue first appeared before the Commission in PacifiCorp's 2013 IRP,
4 Docket No. LC 57, when the Company sought acknowledgement of its action
5 item 8c to install SCRs at Jim Bridger Units 3 and 4 by the end of 2015 and
6 2016, respectively. From the outset of the 2013 IRP process, several parties,
7 including Staff, raised concerns related to the Company's decision-making
8 process and analysis.

9 Ultimately, the Commission declined to acknowledge the Jim Bridger SCRs in
10 the IRP for four reasons: (1) modeling suggested that investment might not be
11 the lowest cost compliance option; (2) gaps in PacifiCorp's analysis; (3) lack of
12 merit in proposed course of action; and (4) PacifiCorp was moving forward with
13 the investment regardless of Commission decision. The Commission
14 specifically stated that it "will undertake a thorough and fair review of the
15 prudence of PacifiCorp's decision in a future rate case proceeding."[27] As this is
16 the Company's first rate case since the completion of these SCR systems,
17 PacifiCorp has included the costs in this case.

18 **Q. What issues related to the 2013 IRP did Staff and Intervenors identify in**
19 **their opening testimony?**

20 A. AWEC, CUB, and Staff take issue with deficiencies in the Company's timing of
21 its decision to proceed with the installation of SCRs at Jim Bridger Units 3 and
22 4 given the timing of its 2013 IRP.

[27] Order No. 14-252, at 7 through 9.

In particular AWEC and Staff point out that PacifiCorp did not allow itself sufficient time to evaluate its decision in an IRP, as the Company had already made the decision to move forward with the SCRs in May of 2013, and did not file its 2013 IRP until April 30, 2013, leaving insufficient time to seriously consider the concerns in its analysis raised by stakeholders in the IRP process.

For example, AWEC states "PacifiCorp simply filed the IRP too late," which meant that during the IRP process "[r]ather than looking for the most economical solution, PacifiCorp sought to justify a decision that had already been made."[28]

Staff made a similar conclusion noting that PacifiCorp issued "its LNTP to the EPC contractor just one month after filing its 2013 IRP, before any parties to the 2013 IRP had a chance to alert the Company of any issues with its analysis."[29]

Additionally, CUB states that one flaw in the Company's analysis is the fact that it "failed to analyze the investment in an IRP prior to committing to the investment which would have allowed the Commission (and Oregon parties) to weigh in on the analysis needed to support the investment."[30]

Q. How does PacifiCorp respond?

A. PacifiCorp disagrees with parties' positions noting that "the fact that review of the IRP – which covered many issues over and above the Jim Bridger SCRs – took longer is not the fault of the Company" and that the alternative would have

[28] AWEC/300, Kaufman/30.
[29] Staff/700, Soldavini/49-50.
[30] CUB/100, Jenks/10.

been to include the Jim Bridger SCR analysis in the 2011 IRP.[31] The Company states that this would have been premature given that the 2011 IRP was filed in March 2011.[32]

Q. Has Staff's position changed from its Opening Testimony?

A. No. First, Staff disagrees with the Company's statement that bringing the Jim Bridger SCR analysis to the Commission in the 2011 IRP would have been premature, because as the Company states itself "[o]nce the Wyoming DEQ issued its December 2009 BART permit with the Jim Bridger SCR installation requirements, PacifiCorp had a legal obligation to comply."[33]

While Staff appreciates that the Company has a responsibility to respond to environmental compliance deadlines, and agrees that not receiving acknowledgement of an investment does not preclude a Company from cost recovery, the Commission has previously noted the important role that IRPs have in cost recovery. In Order No. 12-493 the Commission stated:

> *Although the IRP process is not a legal prerequisite for a utility to seek recovery of investments in rates, we have repeatedly stated that the IRP process serves as a complement to the rate-making process and reduces the uncertainty of recovery. We give considerable weight to actions that are consistent with an acknowledged IRP, and consistency with the plan is evidence to support favorable rate-making treatment of the action. If a utility seeks rate recovery of a significant favorable rate-making treatment of the action. If a utility seeks rate recovery of a significant investment that has not been included in an IRP, we will hold the utility to the same level of rigorous review required by the IRP to demonstrate the prudence of the project.*

[31] PAC/2300, Link/35.
[32] *Ibid*.
[33] PAC/2500, Owen/4.

Regardless of whether a utility intends to use the IRP process for a resource decision, we expect to be kept informed about anticipated major utility investment.[34]

Staff maintains that the Company took a known risk by not bringing its analysis of the investment to the Commission in an IRP before making the decision to proceed.

Time-Line and Compliance Deadline

Q. Did any party raise issues with the Company's timing of its decision to move forward with SCR investment at Jim Bridger Units 3 and 4?

A. Yes. In its Opening Testimony, Sierra Club questions whether the Company's deadline to comply with the Wyoming SIP was real or manufactured and suggests that the Company was not legally bound to the Wyoming compliance deadlines of September 2015, and 2016 for SCR installation at Jim Bridger Units 3 and 4, respectively.[35] Sierra Club states that because at the time PacifiCorp issued its FNTP the EPA had not finalized its FIP for Wyoming, that PacifiCorp made its decision without knowing the federally enforceable deadline. Further, because the EPA ultimately finalized its Wyoming FIP in January 2014, the actual, federally enforceable compliance deadline would have instead been March 2019, five years later.[36]

Sierra Club appears to base its claim on the fact that when the EPA did issue its ruling it "noted that it was accepting the state's deadlines because they were

[34] Docket No. UE 246, Order No. 12-493 at 33.
[35] Sierra Club/100, Fisher/20-27.
[36] Sierra Club/100, Fisher/23.

likely more stringent than what the EPA itself would have otherwise required"[37] and that the Wyoming SIP, "until EPA's finalization, was simply a draft plan".[38]

Additionally, Staff, AWEC, and CUB all raise issues with the Company's timing of its investment decision in relation to its 2013 IRP, which I will discuss later in my testimony.

Q. Does PacifiCorp agree with Sierra Club that the compliance deadlines were not actually enforceable?

A. No. PacifiCorp disagrees with Sierra Club's argument that the SCR investments at Jim Bridger Units 3 and 4 were made prematurely and not based on legally enforceable deadlines.

The Company disagrees with Sierra Club's assertion that the timeline was of PacifiCorp's own manufacture, arguing that "[o]nce the Wyoming DEQ issued its December 2009 BART permit with the Jim Bridger SCR installation requirements, PacifiCorp had a legal obligation to comply"[39] and noting that in 2010, PacifiCorp appealed Wyoming's BART permit requirement to install SCRs the Bridger Units 3 and 4 in 2015 and 2016, but Wyoming maintained its position through the issuance of its SIP that was subsequently approved by the EPA. The Company also points to a Wyoming Public Service Commission (WPSC) Order, which found that the Company had a legal obligation to comply

[37] Sierra Club/100, Fisher/20.
[38] Sierra Club/100, Fisher/24.
[39] PAC/2500, Owen/4.

with the 2015 and 2016 dates, and stated that the "obligation is independent of EPA actions."[40]

Additionally, the Company argues that Sierra Club contradicts its claim that PacifiCorp elected to install SCRs at Jim Bridger Units 3 and 4 in 2015 and 2016, because in 2012, it advocated that the EPA adopt the 2015 and 2016 SCR compliance deadlines for SCR at Jim Bridger Units 3 and 4.[41]

Q. How does Staff respond to the arguments raised by Sierra Club and the Company?

A. I am not an attorney, and make no claim as to when the 2015 and 2016 Wyoming SCR installation deadlines became federally enforceable. However, Staff believes the relevant period for a prudence determination is the May – December 2013 timeframe between which the Company issued its LNTP and FNTP. As such, Staff maintains its Opening Testimony position that by the time the Company issued its final notice to proceed (FNTP) in December 2013, it was reasonable that the Company believe it must act to comply with the Wyoming SIP and EPA SIP.

As noted in Opening Testimony, Staff remains concerned that the Company's analysis and decision-making process up to the issuance of its FNTP point was deficient, and had the Company seriously considered alternative compliance options earlier in its decision-making process it may have found itself with the ability for more flexible compliance deadlines.

[40] Exhibit PAC/2516, Owen/4.
[41] PAC/2500, Owen/7-8.

1 Further, Staff places no weight on PacifiCorp's argument that Sierra Club
2 previously recommended the 2015 and 2016 compliance deadlines be
3 accepted, somehow contradicts its position in this case. It is entirely possible
4 that Sierra Club could have advocated for a particular compliance deadline in
5 the past, and that deadline still not be federally enforceable. In fact, the
6 Company's pointing out that Sierra Club advocated for the 2015 and 2016
7 compliance deadline over an "alternative option that would allow PacifiCorp to
8 install SCR at Jim Bridger Units 3 and 4 within 5 years from the date of EPA's
9 final action"[42] appears to lend credibility to the idea that PacifiCorp may have
10 left alternative compliance options unexplored in the early stages of its decision
11 making-process. Still, Staff finds that by the time PacifiCorp issued its FNTP, a
12 reasonable utility would have acted to comply with the December 2015 and
13 2016 compliance deadlines at Bridger Units 3 and 4, respectively.

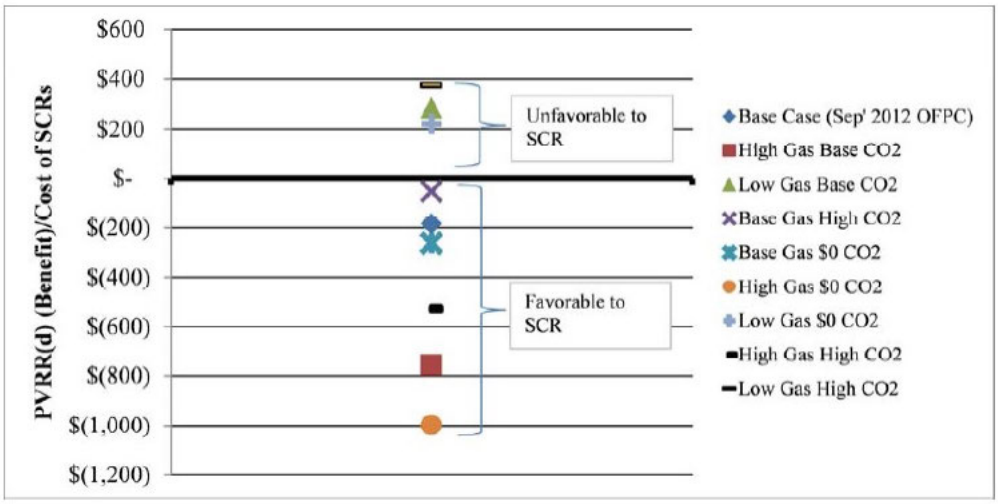
14 *Natural Gas Prices*

15 **Q. Please explain how natural gas prices relate to this issue?**

16 A. As explained by the Company, there is a strong relationship between natural
17 gas prices, CO_2 prices, and the cost-effectiveness of SCR installation at Jim
18 Bridger Units 3 and 4. In the Company's analysis, it tested eight different
19 combinations of natural-gas and CO_2 price assumptions, in addition to a base
20 case, for a total of nine natural gas and CO_2 combinations. The results of this
21 analysis showed that in the three scenarios that assumed low gas prices, the
22 PVRR(d) was unfavorable to the SCRs by as much as $387 million when

[42] PAC/2500, Owen/7.

compared to natural gas conversion as seen in the Figure below.[43] Thus, the reasonableness of PacifiCorp's assumptions and analysis of natural gas prices are of particular relevance in determining prudency.



Q. Given that the economics of the SCRs were so sensitive to the price of natural gas, how did PacifiCorp monitor the status of the natural gas price?

A. PacifiCorp chose to use a breakeven analysis to infer how far natural gas prices would have to fall for gas conversion to have been favorable to installation of SCR systems at Jim Bridger Units 3 and 4. Based on PacifiCorp's analysis, it determined that the levelized natural gas prices from 2016 through 2030 would have needed to fall by 15 percent, from $5.72 MMBtu to $4.86 per MMBtu to achieve a breakeven PVRR(d),[44] meaning that any levelized natural gas price for the same 2016-2030 time period below $4.86 per MMBtu would result in SCR installation *not* being the most favorable compliance option.

[43] PAC/700, Link/104.
[44] PAC/700, Link/101.

The Company also states that it analyzed uncertainty around future natural gas prices by comparing the potential range of future natural gas prices based on historical natural gas prices. The Company came to the conclusion that in the base natural gas price scenarios, the average annual price for Opal natural gas was $5.66 per MMBtu, or 29 percent above 2002-2012 historic price levels, and that among the low natural gas price scenarios, the average annual price for natural gas at Opal over the period 2013 through 2030 was $3.59 per MMBtu, 18 percent below 2002-2012 historic price levels.[45]

Q. Does the Company claim that it continued to monitor the economics of Bridger SCRs after issuing the LNTP and the FNTP in December 2013?

A. Yes. PacifiCorp states that it monitored the changing market conditions before issuing a FNTP in December 2013. Specifically, the Company states that "[b]etween May and December 2013, management personnel were in frequent contact and regularly monitoring the economics of the SCR investment, before issuing the FNTP on December 1, 2013, PacifiCorp once again evaluated natural-gas prices relative to the breakeven price point to assess how changes in market conditions affected customer benefits."[46] PacifiCorp notes that its use of breakeven analysis allowed the Company to monitor changes without having to recreate the entire economic analysis to account for changes in forward gas prices.

[45] PAC/700, Link/105.
[46] PAC/700, Link/106.

1 Additionally, the Company asserts that before issuing the FNTP, PacifiCorp
2 performed an analysis to incorporate its September 2013 OFPC. The results of
3 the Company's analysis showed that the nominal levelized price at Opal was
4 $5.35 per MMBtu from 2016-2030, which remained above the Company's
5 identified $4.86 break-even levelized price. Based on the lower levelized price
6 as compared to the analysis presented in its initial IRP filing, the Bridger SCRs
7 remained the most economical compliance option.[47]

8 **Q. Did any party challenge the Company's analysis in Opening**
9 **Testimony?**

10 A. Yes. In particular, Sierra Club argues that PacifiCorp's records at the time
11 showed that gas prices would likely become – and remain – depressed on a
12 going-forward basis, and that it did not include this information in its analysis,
13 and that that the Company's use of a shortcut breakeven analysis, "which relied
14 on modeling data more than 15 months old at the time of the FNTP was
15 unbefitting for a project of this scale and magnitude."[48] Sierra Club believes the
16 Company acted imprudently by failing to produce "an adequate assessment
17 prior to signing the FNTP" and "in failing to assess up-to-date gas price
18 forwards at the time it made the decision to move forward with the SCR
19 construction."[49]

20 Sierra Club also states that when PacifiCorp produced the Company's
21 December 2013 OFPC on December 31, 2013, the levelized price of gas at

[47] PAC/700, Link/107.
[48] Sierra Club/100, Fisher/54.
[49] Sierra Club/100, Fisher/55.

1 Opal had dropped to $5.00/MMBtu,[50] which based on PacifiCorp's breakeven
2 analysis would have reduced the value of the SCRs to **[BEGIN**
3 **CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** or 80% from the base
4 case of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
5 **Q. How does the Company respond to Sierra Club's assertion?**
6 A. PacifiCorp disagrees with Sierra Club, and admits that though natural gas
7 prices were declining in 2013, they remained above the breakeven price and
8 therefore based on the information that was available when the Company
9 issued its FNTP, thus the SCRs remained least cost. PacifiCorp also states that
10 Sierra Clubs analysis "relies on improper hindsight review and misrepresents
11 the information that was actually available at the relevant times"[51] as Sierra
12 Club's analysis uses data that Company states was not available until after the
13 Company issued its FNTP.
14 PacifiCorp states that before issuing its FNTP, it reviewed its most recent
15 official forward price curve (OFPC) and that it remained well above the SCR's
16 breakeven point. PacifiCorp further states that its economic analysis was
17 designed to allow for "rapid re-assessment of the present-value revenue
18 requirement differential (PVRR(d))."[52] The Company states that after reviewing
19 its most recent OFPC, the base case PVRR(d) continued to be the economic
20 decision by $130 million, and that PacifiCorp was aware that there was
21 "volatility in long-term price forecasts, that natural-gas prices cannot trend

[50] Sierra Club/100, Fisher/46.
[51] PAC/2300, Link/3.
[52] PAC/2300, Link/7.

1 downward indefinitely, and that there was a reasonable possibility that actual
2 natural gas prices could be higher than then-current base-case projections."[53]
3 The Company also disagrees with Sierra Club that short-term trading
4 forwards and one-year EIA projections showed declining natural gas prices,
5 and implies that as these are short-term forecasts, they do not influence long-
6 term planning decisions such as the decision to install SCRs, and reiterates
7 that while short-term prices may have been declining long term prices remained
8 above the breakeven price.[54]

9 **Q. Is there evidence that the Company re-ran its model to reassess the**
10 **value of the Bridger SCRs given that gas prices were falling?**

11 A. No. In reviewing PacifiCorp's responses in Reply Testimony and to data
12 requests,[55] it appears as though the breakeven analysis was the only analysis
13 considered between May and December of 2013. The Company did not rerun
14 its SO model to evaluate the changing economics.
15 The Company notes that the "breakeven analysis obviated the need to
16 conduct additional sensitivities surrounding natural gas price because the
17 Company knew that as long as the natural gas price remained above the
18 breakeven point" the SCRs were superior to natural gas conversion.[56]
19 PacifiCorp further claims that by the time It issued its FNTP, the Company
20 was aware that its share of the SCR cost was reduced by **[BEGIN**

[53] PAC/2300, Link/9.
[54] PAC/2300, Link/25.
[55] Staff/2302, Soldavini/3. PacifiCorp Response to Sierra Club Data Request 1.4(d).
[56] PAC/2300, Link/29.

1 **CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, stating that the
2 Company was aware these reduced costs would partially offset lower natural-
3 gas prices, while recognizing that there was uncertainty in future natural gas
4 prices.[57]

5 **Q. How does Staff respond?**

6 A. Staff noted in its Opening Testimony that while there was evidence that natural
7 gas prices fell between the time the Company issued the LNTP and the FNTP,
8 the levelized price of natural gas remained above the breakeven price at the
9 time the FNTP was issued, meaning that while the favorability of SCR
10 installation relative to natural gas conversion had shrunk, SCR installation at
11 Bridger Units 3 and 4 remained economic.[58] Staff does not change its position
12 on this issue now. The evidence produced by Sierra Club does show that the
13 PVRR(d) was shrinking at the time the Company issued its FNTP, but does not
14 show that the SCRs had become uneconomic by this point.

15 However, Staff supports Sierra Club's broader point that the Company
16 appears to have developed its breakeven analysis and then to have performed
17 little to no other analysis between the time it issued the LNTP and the FNTP,
18 and that a simplified breakeven analysis may be an insufficient level of analysis
19 for an investment of this magnitude. Staff further supports AWEC and Sierra
20 Club's assertion that PacifiCorp recognized that gas prices were dropping
21 through 2013 as evidence by gas forecasts produced by the Company for other

[57] PAC/2300, Link/30.
[58] Staff/700, Soldavini/43.

1 purposes [59,60], and that PacifiCorp's analysis surrounding falling natural gas
2 prices should have been scrutinized to a greater extent.

3 **Q. What is Staff's conclusion?**

4 A. As stated above, the economics of the SCR investments relied heavily on the
5 natural gas price forecast. Given that natural gas prices fell significantly
6 between May and December, Staff believes that a reasonable Company would
7 have taken advantage of the flexibility it states that it gained through negotiating
8 its EPC contract, to rerun its SO model as economics began to change.

9 In conjunction with other known changes, such as changes in coal costs (as
10 discussed below) and changes to PacifiCorp's share of the cost of the SCRs,
11 Staff finds it reasonable to assume that the Company would have wanted to
12 rerun its SO model to determine the overall effect that these multiple changes,
13 which were known at the time, might have had on the economics of the SCRs
14 when considered in conjunction with one another.

15 Finally, Staff agrees that the Company's analysis was deficient in this regard,
16 and that the value of the SCRs was shrinking rapidly. Staff believes this
17 supports Staff's conclusions that the Company had effectively already bet on
18 the SCR being deemed prudent, and Staff's recommendation that the
19 Commission apply a management disallowance. However, based on the
20 evidence in this case, Staff concludes that there was not absolute evidence at

[59] Sierra Club/100, Fisher/50-52.
[60] AWEC/300, Kaufman/43.

the time the Company issued its FNTP to suggest that gas prices rendered the SCRs uneconomic.

BCC Mine Plan & Coal Costs

Q. Please summarize this issue.

A. Sierra Club and AWEC both address the issue of coal costs in their opening testimony, and claim that the Company acted imprudently in its evaluation of (or lack of) changing, or potential changes to coal costs.

Sierra Club states that the Company failed to properly assess the impact that its October 2013 mining plan would have on the value of Bridger SCR decision. Sierra Club asserts that the October 2013 mine plan "resulted in a degradation of value by anywhere from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, but the Company ignored this information in the run-up to signing the FNTP."[61]

AWEC states that PacifiCorp failed to place appropriate weight on coal costs, by failing to test the sensitivity of the investments to higher than expected coal costs. To reach this conclusion, AWEC points to its comparison of annual coal forecasts to actual coal cost values, which it conclude were each forecast was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** actual, and notes that on average, actual coal costs were **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** AWEC's analysis shows that by adding a 20 percent annual increase in Jim Bridger coal cost between 2015 and 2032 results in a net

[61] Sierra Club/100, Fisher/44.

present value of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which exceeds the benefits of the base case scenario from the 2013 IRP and renders six of the nine scenarios analyzed in the 2013 IRP uneconomic.[62]

Q. Please elaborate on Sierra Club's argument that costs and operations at the Bridger Mine changed materially in the months prior to the FNTP.

A. Sierra Club begins by explaining that in the Company SCR analysis, it utilized its January 2013 long-term fueling plan; however, the Company later developed its October 2013 mine plan, which included material changes to the Company's operational assumptions used in the January 2013 long-term fueling plan.[63]

For example, these changes include the fact that under a two-unit scenario, the Company assumed that it would close the Bridger surface mine in 2017, and rely on the underground mine for the remainder of the plant's life through 2037 in the January 2013 long-term fueling plan. This led to the assumption that there would be an acceleration of mine reclamation costs. However, in early 2013, Bridger Coal Company conducted drilling that resulted in the assessment that the underground mine would in fact be depleted by 2023. The October 2013 mine plan reflected this change, and assumed underground mine operations would cease in 2022, and the surfaces mine would now operate in 2037.

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[62] AWEC/300, Kaufman/36-37.
[63] Sierra Club/100, Fisher/32-44.

1 Sierra Club argues that this significant change made it "highly unlikely that the
2 Company would have developed or continued to use a two-unit mine plan that
3 relied on the underground mine, and the acceleration of surface remediation
4 would not have been featured in that two-unit scenario."[64]

5 **Q. How does Sierra Club believe this effected the analysis of Bridger**
6 **SCRs?**

7 A. Sierra Club asserts that the Company affirmed that 2013 October mine plan
8 reflected changed in the relationship between the surface and underground
9 mining operations at BCC.[65] Sierra Club also asserts that the Company has
10 admitted that the October 2013 mine plan had resulted in an increased cost of
11 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to the Bridger
12 SCR retrofit decision, "thereby degrading the value of the SCR by **[BEGIN**
13 **CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[66]

14 Additionally, Sierra Club asserts that once the Company created its October
15 2013 mine plan, the **[BEGIN CONFIDENTIAL]** [redacted] **[END**
16 **CONFIDENTIAL]** of increased reclamation costs associated with accelerated
17 remediation as referenced above, would potentially increase the total
18 discrepancy to as much as **[BEGIN CONFIDENTIAL]** [redacted] **[END**
19 **CONFIDENTIAL]**. [67]

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[64] Sierra Club/100, Fisher/43.
[65] Sierra Club/100, Fisher/42.
[66] Sierra Club/100, Fisher/43.
[67] Sierra Club/100, Fisher/44.

1 Sierra Club concludes that the Company "failed to properly or timely assess
2 the impact that its new October 2013 mining plan would have on the value of
3 the Bridger SCR decision," ignoring new information that showed the potential
4 cost increases by anywhere from **[BEGIN CONFIDENTIAL]** [redacted]
5 **[END CONFIDENTIAL]**.[68]

6 **Q. How does the Company respond to Sierra Club's assertion?**

7 A. The Company states that Sierra Club's analysis is not based on the Bridger
8 Coal Company (BCC) October 2013 mine plan, but an analysis of coal cost
9 changes between the January 2013 and November 2014 long-term fueling
10 plans. PacifiCorp claims this is inappropriate as information from the 2014 long
11 term fueling plan would not have been available to it when the FNTP was
12 issued on December 1, 2013.[69]

13 **Q. Does the Company agree that the October 2013 mine plan resulted in**
14 **increased coal costs of [BEGIN CONFIDENTIAL]** [redacted] **[END**
15 **CONFIDENTIAL]?**

16 A. No, the Company states that Sierra Club is utilizing analysis performed by the
17 Company in its 2015, which demonstrated that if coal costs in the SCR analysis
18 were replaced by the coal costs from the 2015 IRP, the benefits of the SCR
19 investment would have decreased approximately **[BEGIN CONFIDENTIAL]**
20 [redacted] **[END CONFIDENTIAL]** but remained favorable relative to natural
21 gas conversion. The Company argues that Sierra Club does not explain this in

[68] Sierra Club/100, Fisher/44.
[69] PAC/2300, Link/20.

its Opening Testimony and now claims this was the cost increase associated with the October 2013 mine plan.[70]

Q. Has PacifiCorp provided an update as to what it believes the effect of the October 2013 mine plan had on the 10-year budget?

A. Yes. PacifiCorp states that had the Company updated costs to account for the October 2013 mine plan, the SCR benefits would have decreased by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** over the 10-year budget period.[71] PacifiCorp has provided its methodology in Exhibit PAC/2603.

Q. Does the Company explain why it continued to rely on the January 2013 long-term fueling plan?

A. Yes. The Company states that if continued to rely on the January 2013 long-term fueling plan even after the October 2013 mine plan was developed as nothing in the October 2013 mine plan raised concern that costs had significantly changed.[72]

Q. What does PacifiCorp consider significant cost events that would trigger the Company to prepare a new long-term fueling plan?

A. It is not clear. In response to Staff Data Request 753, the Company states that a significant cost events are those that "substantially change long-term generation requirements or substantial changes in costs at the Jim Bridger

[70] PAC/3200, Link/22.
[71] PAC/2600, Ralston/11 and PAC/2603.
[72] PAC/2600, Ralston/12.

1 plant."[73] In this response, the Company has not provided any specific
2 information and appears to have just substituted the word "substantial" for
3 "significant."

4 **Q. Has PacifiCorp explained why, in the two unit, no SCR scenario, the**
5 **surface mine closure occurred in 2018 under the 2013 mine plan versus**
6 **2037 under the October 2013 mine plan?**

7 A. Yes. The Company states that under the October 2013 mine plan, it was
8 assumed that underground mine reserves would be depleted by 2023, as
9 opposed to 2037 as assumed in the January 2013 long-term fueling plan. The
10 Company notes that the drastic change was based on an evaluation of drilling
11 information in early 2013, which determined that its projected new underground
12 area did not provide a suitable underground coal reserve and that the existing
13 reserves would be depleted by 2023.[74]

14 **Q. Does PacifiCorp agree that under the October 2013 mine plan, there**
15 **would have been no need for expedited remediation payments?**

16 A. No. PacifiCorp states the Sierra Club is correct in stating that a two-unit
17 analysis based on information available in fall of 2013 "would remove the
18 increased costs associated with accelerated remediation," but notes that the
19 cost decrease comprises only one component of the overall total differential
20 between the two-unit and four-unit analysis.[75] The Company argues that its
21 analysis, as outlined in PAC/2603, calculates the full impact of the October

[73] Staff/2301, Soldavini/6. PacifiCorp response to Staff Data Request 753.
[74] PAC/2500, Ralston/13-14.
[75] *Ibid.*

2013 mine plan on the two-unit and four-unit scenario differentiation, and shows that the total effect would be to increase the overall cost costs of the Jim Bridger plant by only $16.7 million for the 10 year budget horizon.[76]

Q. What are Staff's conclusions regarding the effect that the October 2013 mine plan had on the economics of the SCRs?

A. Staff agrees with the Company that Sierra Club appears to have misrepresented the Company's position on the effect that the October 2013 mine plan had on the economics of the SCRs. Staff agrees that the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** cost increase Sierra Club asserts the company has admitted to being the impact of the October 2013 mine plan appears to actually be the impact of using the Jim Bridger fueling forecast included in the 2015 IRP.[77] [78] As the 2014 fueling plan was not available when the Company was forced to decide whether to move forward, Staff finds Sierra Club's **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** cost estimate outside the scope of this review.

However, Staff is supportive of Sierra Club's argument that the Company did not properly assess the impact that its October 2013 mining plan would have on the value of the Bridger SCR decision. By PacifiCorp's own analysis, had PacifiCorp incorporated the October 2013 mine plan into its two-unit and four-unit scenario analysis in the fall of 2013, it would have realized that overall

[76] PAC/2600, Ralston/13-14.
[77] *See* Sierra Club/108, Fisher/4-5. UTC Ralston Rebuttal Testimony page 2 line 22-23 through page 3 line 3.
[78] *See* Sierra Club/108, Fisher/12. UTC Ralston Rebuttal Testimony page 2 line 22-23 through page 3 line 3.

costs of the Jim Bridger plant had increased by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** [79] Notably, PacifiCorp appears to have not performed this analysis until after the fact, for the purpose of refuting Sierra Club's analysis, and supports its decision to continue to rely on the January 2013 long-term plan because "no significant cost events" had occurred.[80]

While the Company may not have found the cost change related to the assumption that the underground surface mine would close *14 years earlier than assumed just 10 months prior* significant enough to update its long-term fueling plan, Staff agrees with Sierra Club that a reasonable utility would have sought to quantify the effects of this change on an expenditure as significant as the Jim Bridger SCRs.

The Company repeatedly points to the flexibility it negotiated in its EPC contract, allowing it to issue a LNTP in May but delay a FNTP until December of 2013, as a benefit and evidence of its prudent behavior. Here though, it is unclear to Staff that the Company took advantage of that flexibility (which was presumably negotiated at some cost) by failing to account for known changes months before issuing the FNTP.

Q. How does the Company respond to AWECs claim that it consistently under-forecast coal costs?

A. PacifiCorp does not agree with AWEC's analysis used to assert that the Company systematically under-forecasts coal costs, noting that AWEC relied

[79] PAC/2600, Ralston/14.
[80] PAC/2600, Ralston/12.

on 2013-2020 data to perform its analysis (which was not available to the Company at the time), and compares Jim Bridger plant consumed forecasts with BCC delivered coal costs which make up only a portion of costs.[81]

Further, the Company claims that AWEC incorrectly calculated the changing coal costs, and disagrees that it should have tested the sensitivity of the SCR investments higher-than expected coal prices stating that such sensitivity analysis was unnecessary at the time based on the information the Company had, and the fact that coal costs are typically not as volatile as natural gas and carbon prices.[82]

Q. What are Staff's conclusions on the issue of coal cost forecasts?

A. After reviewing AWEC's workpaper, Staff agrees with the Company that AWEC uses coal prices from 2013-2020 in its analysis, which would not have been available to the Company at the time it made the decision to issue the FNTP (though the Company likely had a very good idea that they had under forecast 2013 costs by December), and Staff agrees that this analysis does not show that the Company acted imprudently in May of 2013 when it issued its LNTP or in December of 2013 when it issued the FNTP.

However, Staff points out that while the Company claims that AWEC's analysis is flawed, the Company does not refute AWEC's larger claim that the Company over forecast coal consumption costs over a more relevant time frame (2003-2012 for example).

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[81] PAC/2600, Ralston/17.
[82] *Ibid*.

Additionally, without additional information from the Company as to what the additional costs for BCC coal that were not considered in AWEC's analysis, it does appear that PacifiCorp's 2013 10-Year Business Plan over forecast coal costs. While Staff does not believe this is evidence to suggest the entire investment into the SCRs was imprudent, it may suggest flaws with the Company's analysis at the time more generally as the business plan was created before the Company's decision to install the SCRs. Staff recommends that if the Company has evidence to refute AWEC's claim, that it provide a comparison of its BCC coal cost forecast to actuals for the years 2000 to 2012 in its next round of testimony.

Warnings by the Commission and Others

Q. Did PacifiCorp ignore signs from the Commission that its proposed course of action may have been flawed?

A. Yes. As pointed out by AWEC, CUB, Sierra Club, and Staff, the Company ignored several warnings by parties and the Commission that its proposed course of action may have put it at risk of not being able to recover the costs of the investments.

For example, AWEC and CUB both point out that in Order No. 08-327 the Commission rejected PacifiCorp's request to extend the depreciable life of the four Jim Bridger units from 2025 to 2037, further stating that:

> Pacific Power assumes that coal-fired generating plants will continue to be an economic source of power "well into the foreseeable future" and will stay in service as long as the plants are operational. Pacific Power also assumes that any increased capital expenditures resulting from

> environmental upgrades will be recoverable in rates because the expenditures will be "for the benefit of customers.[83]

and

> In other words, continued operation of a coal-fired generating plant could become uneconomic, leading to early retirement of the facility. Pacific Power ignores this possibility by assuming both that coal-fired generating plants will remain economic and that all capital expenditures associated with these plants will be recoverable in rates.[84]

Additionally, Staff pointed to the Commission Order in PacifiCorp's 2012 general rate case, Docket No. UE 246, where the Commission determined that PacifiCorp was prudent to take some action to comply with state and federal regulations, but the PacifiCorp acted imprudently in two areas – first, that PacifiCorp did not have legitimate alternative courses of action both in compliance and timing, and failed to alter course of action to consider these alternatives; second – that PacifiCorp failed to perform appropriate analysis to determine the cost-effectiveness of the investments (i.e. what they did provide was deficient), and did not demonstrate the rigorous review that a prudent utility should have performed prior to making these significant investments. As a result, the Commission ordered a partial disallowance of 10 percent.[85]

Staff noted that "though the Commission outlined its concerns related to PacifiCorp's coal investment analysis in Order No. 12-493, PacifiCorp chose to continue down the same path in its decision to invest in Bridger SCRs. In fact, it may even have been the case that by the time the Commission issued its Order

[83] Order No. 08-327 at 3.
[84] Order No. 08-327 at 4.
[85] Order No. 12-493 at 32.

in UE 246…PacifiCorp was too far along its identified compliance option…to be incentivized to complete the necessary analysis."[86]

Q. How does PacifiCorp respond?

A. PacifiCorp states that Staff's criticism that the Company did not allow itself time to sufficiently explore alternatives after the issuance of Order No. 12-493 is unfair, as the Order was not issued until December 2012, after the Company had already conducted its initial economic analysis supporting the Wyoming and Utah pre-approval process, and therefore it could not have been incorporated into this analysis.[87]

The Company also states that Staff mischaracterizes the Company's analysis by claiming that it generally followed along the same lines as the coal analysis in Docket No. UE 246. The Company asserts that Staff ignores the improvement in the modeling process employed in its SCR analysis, stating that the five modeling deficiencies identified in Order No. 12-493 do not apply to the SCR analysis in this case. [88]

The Company implies that the deficiencies identified in Order 12-493 are not relevant here because in this case: the Company examined more than one alternative compliance option, the analysis did not rely on a single point forecast but included nine separate price-policy scenarios, in this case no party claims that PacifiCorp failed to account for the cost of emerging regulations, updated its analysis in February 2013 and monitored changing market

[86] Staff/700, Soldavini/51.
[87] PAC/2300, Link/17.
[88] PAC/2300, Link/18.

conditions before executing its EPC contract and again before issuing the FTNP, and the company did not limit its PVRR(d) analysis to only market purchases.[89]

Q. Is Staff persuaded by PacifiCorp's arguments?

A. No. First, Staff disagrees with PacifiCorp's characterization of its position. Staff does not state or otherwise imply that the two cases were the same. They are, of course, not. Second, Staff's larger argument as referenced above, was that the Company should have realized after the Commission's issuance of Order No. 12-493 that the level of scrutiny the Commission would place on its investment decisions had increased, but instead the Company appeared to have already committed to the SCRs, and had less incentive to reassess its decision as market factors changed, as it had already bet on the Commission allowing recovery of these costs.

Third, Staff does not agree with each of the Company's counterpoints asserting that the deficiencies have been remedied in this case. First, the Company states that in this instance it "examined multiple early exit dates".[90] This is misleading. The Company did examine three compliance scenarios (one more than the analysis the Commission found deficient in Order No. 12-493), but only one retirement scenario was examined before the Company made the decision to proceed with the SCR. Just because the specific number of scenarios analyzed differed does not mean that the general deficiency is

[89] PAC/2300, Link/18-19.
[90] PAC/2300, Link/18.

1 irrelevant. Staff notes that this is also relevant to the second deficiency
2 PacifiCorp states has been addressed in it SCR analysis – just because the
3 Company performed additional sensitivity and scenario analysis, does not
4 mean the Company performed *meaningful* analysis. Again, parties in this
5 docket have called this into question by suggesting that the Company did not
6 perform analysis of alternative compliance options that it knew existed at the
7 time.
8 Next, Staff disagrees with the Company's position that the Commission's
9 finding that its analysis was deficient is not relevant here. Indeed, parties have
10 questioned whether PacifiCorp acted imprudently in not rerunning its full
11 analysis in the time period between May 2013 and December 2013, when it
12 became aware of changes to coal cost and falling natural gas prices.
13 Finally, PacifiCorp states that no parties have in this case stated that
14 PacifiCorp failed to incorporate potential costs of known, emerging regulations.
15 While it is true that no party has suggested that PacifiCorp failed to account for
16 a known, specific regulation, AWEC and CUB make arguments that PacifiCorp
17 failed to account for warnings by the Commission regarding the economic and
18 political landscape of coal investments as discussed above, potentially showing
19 that the Company was aware of a likely regulatory shift away from coal that it
20 did not factor into to its analysis. Staff argues that the risk associated with
21 PacifiCorp's decision to ignore these warnings could be seen as in the same
22 category of deficiency, though admittedly more broad and difficult to quantify.

1 *Approval of SCRs in Other States*

2 **Q. Does PacifiCorp rely on other states' decisions on the SCRs in its**
3 **Reply Testimony?**

4 A. Yes. PacifiCorp dedicates a section of its Reply Testimony to discussing how
5 the other states in which it operates have ruled on the prudency of the Jim
6 Bridger SCRs. The Company notes that none of the state commissions which
7 have ruled on the issue have found the SCR investment imprudent.[91]
8 PacifiCorp notes that in 2020, the California Commission approved full cost
9 recovery of the Jim Bridger SCR investments, and states that the Idaho
10 Commission approved the Jim Bridger SCRs based on an application
11 submitted by the plant's co-owner, Idaho Power Company.[92]

12 **Q. Has any Commission ordered a disallowance of the SCR investment?**

13 A. Yes. The Washington Commission found that "considering the significant
14 economic changes in both coal cost and natural gas pricing between May and
15 December 2013, the decision to continue the SCR installation project was not
16 sufficiently demonstrated by the Company to be prudent in all respects, and the
17 full costs of its decision should not be borne by ratepayers in Washington."[93]
18 The Washington Commission further stated that "Pacific Power increased the
19 risk Washington ratepayers would bear by failing to rerun the SO model when
20 confronted with significantly changed circumstances to its original inputs."[94]

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[91] PAC/2300, Link/43.
[92] PAC/2300, Link/44.
[93] Washington UTC Docket UE-152253, Order 12 at 38.
[94] *Ibid at 39.*

1 Accordingly, as PacifiCorp notes in its testimony, the Washington
2 Commission allowed the Company recovery of its investments, but did not
3 authorize the Company to collect any return on either investment.

4 **Q. Does Staff believe PacifiCorp's discussion of other states review is**
5 **relevant?**

6 A. Not particularly. The prudence determination in Oregon must be based on the
7 record provided in this case, and ultimately the fact that other states may have
8 approved the SCRs has should have no relevance on the prudency
9 determination in this case.

10 *Risk of Market Sales*

11 **Q. Please summarize this issue.**

12 A. In AWEC's opening testimony, it claims that the "primary forecasted benefit of
13 the SCR investment was net system balance, or market transactions," and as
14 such PacifiCorp should have run electric market price sensitivities.[95] AWEC
15 supports its argument by noting that **[BEGIN CONFIDENTIAL]** [redacted]
16 [redacted]
17 [redacted] **[END CONFIDENTIAL]**, indicating a small change in market prices
18 would make the investment uneconomic.[96]

19 **Q. Does the Company agree?**

20 A. No. The Company notes that there was no need for sensitivity analysis around
21 electric market prices as natural gas and electric market prices are highly

[95] AWEC/300, Kaufman/37.
[96] AWEC/300, Kaufman/37-38.

correlated and the prices used to analyze the SCR investments capture the associated change in electricity prices.[97]

Q. Does Staff find this argument relevant in the determination of its final recommendation?

A. No. While Staff agrees that AWEC brings up an interesting point, and Staff would certainly encourage the Company to perform this analysis in the future, there is no analysis on the record to support that "a small change in market prices would make the investment uneconomic,"[98] and thus Staff does not use this particular argument as evidence that the Company's analysis was deficient.

Water Rights

Q. Please summarize this issue.

A. AWEC's Opening Testimony states that PacifiCorp did not consider the value of selling water rights when evaluating the Jim Bridger SCRs, and suggests that such analysis would have increased the value of early retirement. According to AWEC's analysis, early retirement of Jim Bridger Units 3 and 4 would have made the water used for these plants available 17 years sooner; therefore, the value of water for 17 years should have been included as a benefit in the retirement scenarios.

AWEC's analysis estimates that the value of water used by Jim Bridger 3 and 4 ranges from $37 million to $309 million. AWEC argues that at the high end of

[97] PAC/2300, Link/33.
[98] AWEC/300, Kaufman/44.

1 $309 million, the SCR investment would be uneconomic in six of the nine
2 scenarios analyzed.[99]
3 To arrive at the lower, $37 million estimate, AWEC assumes that all the water
4 rights go to growing alfalfa in Wyoming, and multiplies the incremental value of
5 alfalfa over other Wyoming dryland crops per acre.[100]
6 To arrive at the higher, $309 million estimate, AWEC calculates the value of
7 the water rights potentially available if the Company were to build a pipeline to
8 pump water to Cheyenne for industrial uses based on a number of cost
9 assumptions, and the assumption that the pipe has a 90 year life, that the water
10 price escalates at 3 percent per year, and a capital cost of 10 percent per
11 year.[101]
12 **Q. Please describe the Company's response to AWEC's analysis.**
13 A. The Company disagrees with AWEC's assertion that the proposal to value the
14 water rights by building a water pipeline is not within PacifiCorp's core
15 business, and building a pipeline to facilitate the sale of water rights would be a
16 risk to customers. The Company further notes that AWEC's analysis ignores
17 permitting barriers, costs associated with developing such a substantial
18 diversion project and the lengthy planning and construction timeline. The
19 Company additionally notes that there is no reason to assume that any

[99] AWEC/300, 39-40.
[100] AWEC/300, Kaufman/40.
[101] AWEC/300, Kaufman/40-41.

1 revenues from water sales would be immediately available, if the plan were
2 even to be approved in the first place.[102]
3 PacifiCorp also disagrees with AWEC's claim that water for oil and gas uses
4 is valued at $0.01 to $0.015 per gallon, stating that there is no support
5 suggesting that a market for water at these rates exists on a long term basis, as
6 would be necessary to justify construction of a pipeline. The Company claims
7 that industries such as fracking and drilling may be willing to pay elevated
8 prices "to avoid the time and expense of hauling water over long distances" and
9 notes that the City of Cheyenne charges industrial and commercial water users
10 $0.005 per gallon plus a monthly service charge.[103]
11 **Q. How does Staff respond to AWEC's analysis and PacifiCorp's argument**
12 **against it?**
13 A. Staff agrees with AWEC that the difficulty in modeling water rights is not a
14 sufficient argument for not considering a potentially valuable benefit in its
15 analysis, but Staff does not believe that AWEC's analysis itself is evidence to
16 suggest that the Company's investment was imprudent.
17 Staff takes no issue with AWEC's assertion that water rights should have
18 been valued in the Company's analysis. However, Staff does not go as far as
19 saying that a reasonable utility must have included this in its analysis, because
20 Staff has found no evidence that at in the period leading up to the SCR
21 investment there was any major concern regarding the non-valuation of water

[102] PAC/2600, Ralston/25.
[103] https://www.cheyennebopu.org/Residential/Billing-Rates/Water-Sewer-Rates. Accessed by Staff July 17th, 2020.

rights. Although Staff may find it reasonable to include such analysis today, in 2020, Staff cannot say with certainty that it was unreasonable to exclude this analysis in the period leading up to PacifiCorp's decision to proceed with the SCRs at Jim Bridger Units 3 and 4. Based on this, Staff recommends that the Commission not use AWEC's analysis as evidence that the Company's investment was imprudent.

Liability & Continued Operations

Q. Please summarize this issue.

A. Sierra Club asserts that the liability of the Jim Bridger SCRs exceeded the cost of contract termination well before the project reached completion and therefore the Company acted imprudently in not terminating the contract. Sierra Club additionally argues that the continued operations of the Jim Bridger plant harms ratepayers.[104]

Q. Why does Sierra Club believe that the liability of the Jim Bridger SCRs exceeded the cost of contract termination well before the project reached completion?

A. Sierra Club asserts that after the Company issued its FNTP, the price of gas continued to fall and by December of 2014 the Company projected that the forward cost of gas at Opal has fallen to $4.47/MMBtu, below the breakeven price identified by the Company. Sierra Club asserts that utilizing PacifiCorp's same breakeven analysis in December 2014 would have resulted in more than

[104] Sierra Club/100, Fisher/61.

a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** liability for pursuing the SCRs.[105]

Sierra Club further notes that even though the SCRs were already under construction, there was a point in the construction process where it still would have been prudent to terminate the project prior to completion. Sierra Club argues this point in time would have occurred between January 2015 and April 2015. Sierra Club asserts that the Company's obligation under a prudence standard is "not only to make a rational and competitive decision on the basis of the most up-to-date information at its disposal at the time that it makes a commitment, but to continuously assess whether its decisions are serving the best interest of ratepayers."[106] Sierra Club notes that the Company did not re-asses the Bridger SCRs using the SO model at any time after 2013, or in its 2015 IRP, and concludes that customers would have benefited if the Company elected to terminate the projects and retire the units in 2015.[107]

Q. Does PacifiCorp agree that it should have terminated the contract in 2015 based on changes to natural gas prices?

A. No. PacifiCorp states if the Company had changed paths in 2015 to convert to natural gas, the costs would have been substantially higher and that Sierra's Club analysis based on the PVRR(d) analysis from 2013 is improper and does not demonstrate that changing course in 2015 would have been prudent.[108]

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[105] Sierra Club/100, Fisher/58.
[106] Sierra Club/100, Fisher/59.
[107] Sierra Club/100, Fisher/62.
[108] PAC/2300, Link/32.

1 PacifiCorp further states that, in fact, Sierra Club used the breakeven analysis
2 created to monitor the PVRR(d) between natural gas conversion and SCRs, not
3 the relationship between SCRs and retirement in 2015 and 2016 to support its
4 argument that the Company should have retired Jim Bridger Units 3 and 4 in
5 2015. The Company states that this is an inappropriate application, but that
6 even using Sierra Club's "analysis shows that termination of the EPC contract
7 and early retirement of Units 3 and 4 would have cost customers $180 million
8 more than SCR, without considering the costs of terminating the EPC
9 contract"[109] noting that the PVRR(d) between retirement in 2015 and 2016 and
10 the SCRs was substantially higher than the PVRR(d) between gas conversion
11 and the SCRs ($588 million[110] versus $183 million[111]).
12 The Company claims that had it changed course in 2015, it would have taken
13 approximately 24 months to complete conversion of Jim Bridger 3 and 4 to gas
14 retirement, and states that since the Company's 2013 assessment of
15 converting Jim Bridger Units 3 and 4, it understood that costs of such a
16 conversion had changed.[112] The Company states that it knew by 2014 that
17 implementation costs for Naughton 3 conversion were significantly higher
18 **([BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL])** than originally
19 anticipated. If this premise was applied to Jim Bridger Units 3 and 4, the
20 Company would have understood that its original costs were understated.[113]

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[109] PAC/2300, Link/33.
[110] PAC/2300, Link/16.
[111] PAC/2300, Link/6.
[112] PAC/2500, Owen/16.
[113] *Ibid.*

1 **Q. Does Staff agree with Sierra Club's analysis and claim that PacifiCorp**
2 **should have terminated the EPC contract and retired?**
3 A. Generally, no. Staff agrees with PacifiCorp that Sierra Club applied the
4 breakeven analysis PacifiCorp designed to compare the economics of natural
5 gas conversion and SCRs, not SCRs and retirement. As the PVRR(d) of SCRs
6 to retirement was greater than the PVRR(d) between SCRs and retirement, it
7 stands to reason that the breakeven point would have been lower than the
8 breakeven point developed by PacifiCorp to compare the PVRR(d) of SCRs
9 and conversion to natural gas. It is certainly possible that the breakeven point
10 for this relevant comparison may have occurred in the same early 2015
11 timeframe, but it is not clear from the evidence on the record in this case. Even
12 if this alternate breakeven threshold had been crossed, presumably some form
13 of replacement power must be assumed, which does not appear to have been
14 taken into account in Sierra Club's analysis.
15 Staff does; however, find Sierra Club's assertion that PacifiCorp should have
16 been monitoring the costs of the project reasonable. If PacifiCorp became
17 aware that the costs of terminating the project outweighed the costs of contract
18 termination plus an alternate form of compliance (conversion to natural gas or
19 retirement plus replacement power), the prudent decision may have been to
20 terminate the contract and change course.
21 Staff finds that Oregon's prudence standard is based on what the Company
22 knew at the time it made its investment decision, but agrees with Sierra Club
23 that a prudent utility continues to monitor and update its analysis until that final

1 action is required. In other words, a utility cannot avoid a prudence
2 disallowance by making a premature decision. Staff will further address this
3 issue in briefing.

4 **Q. Why does Sierra Club claim that continued operations of Jim Bridger**
5 **has harmed ratepayers?**

6 A. Sierra Club claims that PacifiCorp ratepayers would have benefited by as much
7 as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** by
8 December 2015 if the Company had retired Jim Bridger 3 and 4 in 2015/2016
9 rather than installing SCRs. Sierra Club asserts that this value is "remarkably
10 close to a damage value derived from the Company's most recent IRP, and
11 then accounting for the costs of the SCRs."[114] Sierra Club states that the 2019
12 IRP showed a ratepayer benefit of $141 million if the Company sought
13 retirement of Jim Bridger 3 and 4. Sierra Club then states that adding the total
14 cost of the SCRs **[BEGIN CONFIDENTIAL]** [redacted] **[END**
15 **CONFIDENTIAL]** to this $141 million results in **[BEGIN CONFIDENTIAL]** [redacted]
16 [redacted] **[END CONFIDENTIAL]** in customer savings, in 2019 dollars, if the
17 Bridger SCRs had been avoided.[115]

18 **Q. How does the Company respond?**

19 A. The Company disagrees with Sierra Club. As discussed above, the Company
20 rejects the assertion the breakeven analysis developed to measure the relative
21 benefits of SCRs to natural gas conversion can be used to measure the relative

[114] Sierra Club/100, Fisher/62.
[115] *Ibid.*

benefits of the SCRs to retirement. The Company claims that using Sierra Club's analysis, based on natural gas prices as of December 2015, installing the SCRs remained **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** less than the cost of retirement, without factoring in the contract termination costs.[116]

The Company also notes that Sierra Club's claim that the 2019 IRP shows customer benefits of $141 million if Units 3 and 4 were retired is incorrect, and based on SO model results from the initial portfolio-development phase of the 2019 IRP, before the Company had refined its model to capture a more granular reliability assessment.[117] The Company also argues that Sierra Club's calculation focuses on just two of the 30 cases developed during the initial portfolio development process from the 2019 IRP, noting that "case P-45, which is the precursor to the 2019 preferred portfolio, assumes Jim Bridger Units 3 and 4 operate through 2037 and is $139 million lower cost" than the case Sierra Club references.[118]

Q. What is Staff's recommendation?

A. Staff recommends that the Commission not utilize Sierra Club's argument that continued operations of Jim Bridger has harmed ratepayers as evidence that the investment decision in 2013 was imprudent. While Sierra Club's argument may certainly be relevant for considering the prudence of future investments at Jim Bridger, Sierra Club's reliance on information from the 2019 IRP to support

[116] PAC/2300, Link/40.
[117] PAC/2300, Link/41.
[118] PAC/2300, Link/41.

its argument that ratepayers could have saved **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is based on hindsight and therefore outside the scope of this particular prudency decision.

Staff Summary and Recommendation

Q. What was Staff's Opening Testimony recommendation?

A. In opening testimony, Staff recommended a 10 percent management disallowance for the SCR investments at Jim Bridger Units 3 and 4. Staff concluded that while the Company may have acted prudently in beginning the process of compliance with the Wyoming SIP and EPA FIP, PacifiCorp's analysis and timing were deficient.[119]

Q. Has Staff changed its recommendation from Opening Testimony?

A. Staff's position remains generally unchanged. However, in response to issues raised by AWEC, CUB, and Sierra Club in their opening testimony, as well as new information received from the Company regarding the level of Jim Bridger Unit 3 & 4 SCR depreciation, Staff corrects its original recommendation while also proposing an alternative recommendation for the Commission's consideration.

Q. Staff noted above that it believes PacifiCorp has not correctly calculated the net book value of the SCR investments. Please explain.

A. In response to Staff Data Request 750, the Company states that it seeks recovery of the net book balance of these investments as of December 31, 2020. The Oregon allocated net book balances for each environmental

[119] Staff/700, Soldavini/49.

1 compliance project for which the Company seeks recovery of in this case, as
2 proposed by the Company, can be seen in the table below.[120]

3 **[BEGIN CONFIDENTIAL]**

[redacted]

4 **[END CONFIDENTIAL]**

5 Based on PacifiCorp's proposed depreciation rates for the Jim Bridger 3 and
6 4 SCRs, the SCRs are only **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN**
7 **CONFIDENTIAL]** depreciated. Using PacifiCorp's proposed depreciation rates,
8 the SCRs would not be fully depreciated until 2035, 10 years later than
9 Oregon's depreciable life for Jim Bridger. Accordingly, Staff believes that
10 PacifiCorp's net book value for the Jim Bridger Unit 3 and 4 SCRs uses
11 incorrect assumptions about the useful life of Jim Bridger. Staff contends that
12 as this is the first rate case since these investments were placed into service,
13 the correct ratemaking treatment should be based on the current standard,

[120] Exhibit Staff/2301, Soldavini/3. PacifiCorp Response to Staff Data Request 750.

which removes plant from rate at the end of its depreciable life in the jurisdiction in which recovery is sought.

Based on the 2025 depreciable life of Jim Bridger Units 3 and 4, the correct Oregon allocated net book balance of the SCRs for Jim Bridger Units 3 and 4 should be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** versus the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** PacifiCorp is requesting in its filing. This means that even if the Commission ultimately rejects Staff's other recommendations surrounding the prudence of the investments, Staff recommends a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** adjustment to PacifiCorp's requested rate base. Staff's calculation can be found in the table below.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Why did Staff not propose this adjustment in Opening Testimony?

A. Staff was unaware of the fact that PacifiCorp was applying depreciation rates to its environmental compliance costs that do not match with the depreciable lives set in the Company's last depreciation case until Staff received the Company's response to Staff Data Request 750 on July 9th, 2020. Accordingly, Staff is proposing this adjustment now. Staff notes that this issue applies not just to the Jim Bridger SCRs, but to the Company's other environmental compliance investments as well. Staff will propose similar adjustments in the applicable sections.

1 **Q. Based on this update, what is Staff's recommendation?**

2 A. Staff recommends the Commission require that PacifiCorp comply with the
3 2025 depreciable life of the Jim Bridger 3 and 4 SCRs and require that the
4 Company fully depreciate these investments over the 10 year period from 2015
5 to 2025 (the time period for which they are considered used and useful in
6 Oregon). This results in an Oregon net book allocation of **[BEGIN**
7 **CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as of December
8 31, 2020.

9 Starting from Staff's recommended Oregon allocated net book value, Staff
10 recommends the Commission:

11 1. Apply a 10 percent management disallowance equal to approximately
12 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**; OR
13 2. Allow the full cost of the investments into rates (based on Staff's
14 recommended OR allocated net book value), but not allow the Company
15 to collect a rate of return associated with the Jim Bridger SCRs.

16 **Q. Why does Staff believe this is the appropriate recommendation?**

17 A. As Staff noted above and in Opening Testimony, Staff finds that the Company
18 appears to have acted prudently in May of 2013, when it issued its limited
19 notice to proceed, and again in December of 2013, when it issued its final
20 notice to proceed with the installation of Selective Catalytic Reduction systems
21 at Jim Bridger Units 3 and 4 to comply with what Staff believes were reasonably
22 assumed to be enforceable State and Federal guidelines.[121]

[121] Staff/700, Soldavini/19.

1 Staff finds it is difficult to determine a precise dollar figure which represent the
2 costs to ratepayers of PacifiCorp not having explored, or performed additional
3 and alternative analyses. Staff's adjustment accounts for the fact that while
4 there is no definitive evidence to show that moving forward with SCR
5 installation at Jim Bridger Units 3 and 4 was uneconomic at the time it issued
6 the LNTP in May 2013 or the FNTP in December 2013, the level of analysis
7 PacifiCorp engaged in was deficient given the significant warnings it had
8 received from the Commission and the concerns raised by other parties.
9 Staff remains concerned that several of these deficiencies arose because the
10 Company had all but decided on its course of action before it filed its 2013 IRP,
11 and before it had time to sufficiently address the concerns raised by the
12 Commission in its UE 246. By the time the Company filed its 2013 IRP, it had
13 already filed both its application for a CPCN with Wyoming and its application
14 for pre-approval in Utah, likely leaving little incentive to perform additional
15 analysis.
16 Staff contends that the Company appears to have bet on the fact that if it could
17 receive pre-approval from two of the six states it operated in, this would be
18 evidence enough to support its claim to prudence. This is evidenced by the fact
19 that even after the Commission recommended a similar disallowance in
20 UE 246, PacifiCorp chose not to change the analysis it presented to the
21 Commission in its 2013 IRP, and instead relied on the same analysis presented
22 to the Utah and Wyoming Commission, and issuing its LNTP to the EPC

contractor just one month after filing its 2013 IRP, before any parties to the 2013 IRP had a chance to alert the Company of any issues with its analysis. As Staff noted above, the Company took a known risk by not bringing its analysis of the investment to the Commission in an IRP before making the decision to proceed. This risk does not preclude cost recovery, but it must be seen as a risk nonetheless. The Company took an additional risk by not using the flexibility provided to it under the EPC contract to reassess the economics of the SCR investments given known changes such as natural gas prices and coal costs. While Staff does not believe there is evidence on the record to support that either of these changes would necessarily render the decision uneconomic in isolation, based on the information known at the time, the Company chose not to perform a comprehensive analysis and rerun its SO model at any point after February 2013.[122] Staff finds that a reasonable Company would have performed a comprehensive analysis at some point between issuing its LNTP in May 2013, and its FNTP in December 2013.

[122] Staff/2302, Soldavini/3. PacifiCorp Response the Sierra Club Data Request 1.4(d)

1 **ISSUE 2, HAYDEN SCRS**

2 **Q. Please describe the issue of Hayden SCRs.**

3 A. Hayden is a two-unit coal-fired generation facility located in Colorado and
4 operated by Public Service Company of Colorado (PSCo). PacifiCorp is a
5 minority owner of both Hayden Unit 1 and 2. PacifiCorp is a joint owner of
6 Unit 1 with PSCo, and owns 24.5 percent. Unit 2 is jointly owned by PacifiCorp,
7 PSCo and Salt River Project. PacifiCorp owns 12.6 percent of Hayden Unit 2.
8 The Company states that the SCRs at Hayden Units 1 and 2 were required to
9 be installed by December 31, 2016, by the State of Colorado's Regional Haze
10 SIP. The Company also states that on January 26, 2011, the Colorado Public
11 Utilities Commission (CPUC) approved the installation of the SCRs at Hayden,
12 "finding that PSCo had demonstrated that the installation of the project was in
13 the best interests of customers but still required the filing of a modified CPCN
14 application primarily because the cost of information presented was not
15 adequate" and notes that the CPCN was approved on July 18, 2012.[123]
16 PacifiCorp notes that the terms of joint ownership are governed by a
17 Participation Agreement, which "mandates the installation of capital
18 improvements that are required by applicable law."[124] As described in the
19 sections below, the Participation Agreement is of particular relevance as the
20 determination of the Company's prudency in agreeing to SCR installation at

[123] PAC/800, Teply/49.
[124] PAC/800, Teply/50.

Hayden 1 and 2 hinges on whether PacifiCorp's actions were reasonable given that it is a minority owner of Hayden 1 and 2.

Q. Did the Commission consider acknowledgement of the Hayden SCRs in an IRP?

A. Yes. In the 2013 IRP, the Commission did not acknowledge Hayden Unit 1 and 2 SCRs as they were not an action item in the IRP. The Commission required PacifiCorp to hold a confidential technical workshop to review existing analysis on Craig and Hayden investments within three months.[125]

Q. Has this Commission disallowed a portion of an investment for a minority plant owner, even in the instance that the investment was ultimately deemed prudent?

A. Yes. In Order No. 13-132, the Commission imposed a one-time 10 percent disallowance for the Oregon portion of Idaho Power's investment related to environmental upgrades at Jim Bridger Unit 3 for management failures. The Commission stated that while they found the investment in Bridger 3 prudent, and that Idaho Power's improper conduct did not,

> *by providence, harm ratepayers, its lack of management oversight put ratepayers at risk. It failed to exercise the reasonable standard of care we expect utilities to exercise as co-owners of a generation facility. To ensure future compliance with this standard, we find a one-time disallowance to management expense of $40,000 equivalent to 10 percent of the Oregon portion of the investment to be appropriate.*[126]

[125] LC 57, Order No. 14-252.
[126] Docket No. UE 233. Order No. 13-132 at 7.

Specifically, the Commission noted that:

> a minority owner who seeks to pass through to its ratepayers the costs of environmental upgrades may not sign away its independent duty to review and carefully consider a majority owner's decision-making. While a minority owner is not required to conduct independent studies that duplicate the work of the majority shareholder, in this case Idaho Power admits it was unaware of the existence of the key study underlying the decision to upgrade Bridger 3. This level of oversight is inadequate.[127]

Q. Did any parties recommend a disallowance of the Hayden SCRs in opening testimony?

A. Yes. Sierra Club recommended the Commission disallow the Company's SCR investments at Hayden, [128] totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon allocated net book basis.[129]

Q. What does Sierra Club base its recommendation on?

A. Sierra Club lists eight reasons for disallowing the investments.[130] They are as follows:

1. PacifiCorp failed to engage successfully/meaningfully in PSCo's 2010 emission reduction plan;

2. PacifiCorp failed to assess the joint cost of signing a new coal contract for Hayden and moving forward on the SCRs, which led the Company to make two separate elections that should have been made jointly;

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[127] Docket No. UE 233. Order No. 13-132 at 6.
[128] Sierra Club/100, Fisher/88.
[129] Staff calculated based on PacifiCorp response to Staff Data Request 750.
[130] Sierra Club/100, Fisher/6-7.

3. PacifiCorp failed to press PSCo to conduct updated cost effectiveness studies on the Hayden SCRs, and did not pursue appropriate due diligence documentation on the benefits or risks of pursuing the SCRs;

4. PacifiCorp failed to pursue an alternative retirement strategy with PSCo, and incorrectly agreed to an unenforceable and premature compliance deadline;

5. PacifiCorp's assessment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** but the Company signaled its approval to PSCo;

6. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**;

7. PacifiCorp failed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**; and

8. PacifiCorp **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Does the Company accept Sierra Club's recommendation?

A. No. The Company maintains that its investment decision was prudent and that it acted prudently in assessing and pursuing its obligation, rights, and options under the Hayden Participation Agreement. The Company maintains that its

1 participation in the Hayden Unit 1 and 2 SCR projects were necessary to
2 maintain compliance with legally enforceable requirements.[131]
3 **Q. Why does Sierra Club believe that PacifiCorp failed to engage**
4 **meaningfully in in PSCo's 2010 emission reduction plan?**
5 A. Sierra Club implies that PacifiCorp did not engage meaningfully in PSCo's 2010
6 emission reduction plan in part because it was not granted the same incentives
7 that PSCo was under the Colorado Clean Air Clean Jobs Act (CACJA).[132]
8 Sierra Club further states that in none of the nine scenarios reviewed by PSCo
9 in its application before the Colorado PUC looked at retirement of Hayden, and
10 each included installation of SCRs at Hayden 1 and 2. Sierra Club maintains
11 that PacifiCorp "bore a due diligence responsibility" with respect to its
12 ownership share of Hayden, and that there is no evidence to suggest that
13 PacifiCorp sought to negotiate with PSCo with respect to the Hayden SCRs,
14 and no evidence that PSCo assessed any alternative compliance options.[133]
15 Sierra Club additionally states that in the documents provided by PacifiCorp
16 there is no evidence that PacifiCorp corresponded with PSCo inquiring on the
17 value, benefit or the risks of the project, and that all correspondence is
18 "dedication to obtaining signatures on work orders."[134]
19
20

[131] PAC/2600, Ralston/43.
[132] Sierra Club/100, Fisher/70.
[133] Sierra Club/100, Fisher/72.
[134] Sierra Club/100, Fisher/73.

1 **Q. How does PacifiCorp respond?**

2 A. PacifiCorp does not, generally, refute these claims by Sierra Club in its reply
3 testimony. The only point of rebuttal, as far as Staff notices, is that the
4 Company notes that on October 27, 2010 PacifiCorp filed a challenge to
5 Colorado's BART determination, citing improper application of the EPA's
6 BART Guidelines. The Company states that its challenge was ultimately
7 unsuccessful.[135]

8 **Q. How does the Company respond to Sierra Club's claim that it agreed to**
9 **an unenforceable premature compliance deadline?**

10 A. PacifiCorp disagrees with Sierra Club that the compliance deadlines were
11 unenforceable. Sierra Club asserts that the EPA's final approval was clear that
12 the facilities under consideration would have a five year deadline to retrofit
13 coal units.[136] PacifiCorp asserts that this claim is unfounded, noting that the
14 Colorado Regional Haze SIP required installation of SCRs by December 31,
15 2016 and further notes that Sierra Club's claim that the compliance deadlines
16 were unenforceable is incompatible with the idea that Colorado would require
17 adoption of a plan under its CACJA but not compliance with that plan
18 "especially after SCRs were approved as "needed in the public interest" by the
19 Colorado PUC.[137]

[135] PAC/2600, Ralston/29.
[136] Sierra Club/100, Fisher/76.
[137] PAC/2600, Ralston/36.

Q. Does Staff find PacifiCorp's agreement with PSCo's decision to comply with the Colorado PUC's compliance deadline of December 31, 2016 to be reasonable?

A. Based on a review of Sierra Club's and PacifiCorp's testimony on this issue, Staff is persuaded that it was reasonable for PSCo, and by extension PacifiCorp to have acted to comply with the deadlines approved by the Colorado PUC.

Q. Above, it was noted that Sierra Club faulted the Company for failing to assess the joint cost of signing a new coal contract for Hayden and moving forward on the SCRs. Please explain the relevance of the Hayden coal supply agreement.

A. Sierra Club points out that in PSCo's application for a CPCN before the Colorado Commission, it stated it signed a new coal contract for Hayden, and that the contract extended to 2027.

Sierra Club finds it "extraordinary (a) the PSCo decoupled its decision to sign a new long-term coal contract from the CPCN, and (b) that PSCo elected to sign a coal contract in advance of the Colorado commission's approval of its SCR CPCN."[138] Sierra Club argues that it was inappropriate to assess the value of the coal contract and the SCR separately as it claims the contract "would have been avoidable if the plant were to have shut down." Sierra Club further faults PSCo for signing the contract after learning that it would be 24

[138] Sierra Club/100, Fisher/74.

1 percent more expensive than anticipated when the Company put together its
2 emissions reduction plan.[139]
3 Sierra Club states that PacifiCorp had a role in evaluating and negotiating the
4 CSA, evidenced by testimony PSCo provided to the Colorado Commission
5 which states that it had worked with PacifiCorp to negotiate the coal-supply
6 agreement.[140]
7 **Q. How does PacifiCorp respond to Sierra Club's claim that its own**
8 **assessment of Hayden 1 indicated that the SCR projects should not**
9 **move forward, but the Company elected to ignore this information?**
10 A. PacifiCorp disagrees with this categorization, and claims that Sierra Club basis
11 its assertion on a hypothetical early retirement analysis. PacifiCorp agrees that
12 it did perform a hypothetical analysis comparing early retirement of Hayden
13 Unit 1 in 2015 versus an SCR retrofit, "where no take-or-pay coal contract
14 termination costs applied" that showed a **[BEGIN CONFIDENTIAL]** [redacted]
15 **[END CONFIDENTIAL]** benefit if Hayden Unit 1 was assumed to hypothetically
16 retire in 2015. PacifiCorp notes that it also ran the analysis in the case where
17 coal contract termination costs would apply, which showed that installation of
18 the SCR had a benefit of **[BEGIN CONFIDENTIAL]** [redacted] **[END**
19 **CONFIDENTIAL]** versus retirement.[141]
20 PacifiCorp further notes that coal contract termination costs would have
21 applied, because it did not have the grounds to trigger the change-in-law

[139] *Ibid.*
[140] Sierra Club/100, Fisher/75.
[141] PAC/2600, Ralston/37.

provision or the CPCN termination provision in the Hayden coal supply agreement (CSA). Staff takes this response to mean that PacifiCorp believes there was no internal analysis showing the Hayden Unit 1 project should not move forward.

Q. Please summarize the CSA's change-in-law provision that Sierra Club implies could have helped PacifiCorp to avoid the take or pay provision.

A. The Hayden CSA has language that allows the Buyer to exercise a change-in-law provision, and terminate the CSA If a **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL].**[142]

Q. How does PacifiCorp respond to the change-in-law provision?

A. The Company states that the only condition that would have applied would have been to show **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL].**[143] PacifiCorp additionally claims that the determination regarding whether the change-in-law requiring the installation of the SCRs was **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** would need to be based on the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** of all the units' owners, not just PacifiCorp, which PacifiCorp

[142] PAC/2600, Ralston/38.
[143] *Ibid.*

1 implies would be difficult based on the "strong public record that the SCRs were
2 prudent and not **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END**
3 **HIGHLY CONFIDENTIAL]**.[144]
4 PacifiCorp maintains that in order for it to not have agreed to the installation
5 of the SCRs at Hayden, the Hayden Participation Agreement requires a "non-
6 consenting owner" to "assert that the Operating Agent (and other owners) are
7 in default if it cannot be demonstrated that applicable law requires the addition.
8 In that case, whether or not a default had occurred would be decided by
9 arbitration."[145]
10 **Q. Did PacifiCorp proceed with arbitration?**
11 A. No. The Company argues that there was no dispute that "applicable law
12 required the installation of the SCRs."[146] The Company concluded it did not
13 have a "sound basis to challenge PSCo's decision.[147]
14 **Q. Why does Sierra Club believe that PacifiCorp performed a flawed**
15 **assessment of its arbitration potential?**
16 A. Sierra Club disagrees that PacifiCorp would have failed had it elected to bring
17 the retrofit decision to arbitration as "PSCo's move to install SCR at Hayden
18 was not consistent with generally accepted practices for electric utilities....and
19 these should have been PacifiCorp's starting position in an arbitration
20 claim."[148]

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[144] *Ibid.*
[145] PAC/2600, Ralston/34.
[146] *Ibid.*
[147] *Ibid.*
[148] Sierra Club/100, Fisher/83.

Sierra Club rests this claim on the assertions that:

1. PSCo should have identified the latest possible compliance date available under the law;
2. PSCo's election to install SCR at Hayden "was not a cost-effectiveness decision";[149]
3. Any assessments conducted by PSCo in 2010 or 2011 would have been out of date by the time PSCo was seeking to move forward with the retrofit;[150]
4. "A December 2016 installation date for SCRs at Hayden was not required under the Regional Haze SIP, especially because EPA had not yet approved the state plan…PSCo had alternative options to comply" which it did not explore;[151]
5. The SCR retrofits at Hayden were not specifically required under the CACJA, which sought a system-wide approach to achieving emissions reductions that could have been achieved at other facilities or through unit retirements.[152]

Q. Did PacifiCorp explore any other options other than arbitration?

A. Yes. In March 2014, PacifiCorp explored the option of selling its interests in Hayden Units 1 and 2 as an alternative to environmental compliance costs. The

[149] Sierra Club/100, Fisher/83.
[150] *Ibid.*
[151] Sierra Club/100, Fisher/84.
[152] *Ibid*.

Company initiated a Request for Expressions of Interest in Hayden Units 1 and 2, but received no expressions of interest.[153]

Q. After reviewing Sierra Club and PacifiCorp's positions, what is Staff's recommendation regarding the prudence of the Hayden Unit 1 and 2 SCRs?

A. Staff recommends the Commission find the costs of the Hayden Unit 1 and 2 SCRs prudent. Staff agrees with Sierra Club that PacifiCorp could, and perhaps should, have pushed PSCo harder to assess alternative compliance options, and does agree with Sierra Club's assertion that being a minority owner of a plant is not an excuse PacifiCorp's duty to review PSCo's decision making process.

However, in this instance Staff finds that based on the Commission's prudence standard as outlined in Order No. 13-132, the Company did not sign away its independent duty to review and carefully consider PSCo's decision. PacifiCorp was aware of PSCo's analysis, and by Sierra Club's own assertion was involved of the negotiation of the Hayden CSA. The Commission in Order No. 13-132 states that the minority shareholder does not need to perform independent studies that duplicate the work of the majority shareholder; however, in this instance PacifiCorp was aware of PSCo's analysis, assessed its options for potential litigation, presented its analysis to the Commission, and further assessed the option of selling its rights to Hayden Units 1 and 2.

[153] Staff/2301, Soldavini/217. PacifiCorp response to Staff Data Request 2301.

Q. Does Staff with Sierra Club's recommendation to disallow the Hayden CSA take or pay provision from rates in this general rate case?

A. No. Staff agrees with PacifiCorp that the CSA has been in Oregon rates and effecting each year's net variable power cost filing since 2011, and as such this is an issue that should be dealt with in the Company's Transition Adjustment Mechanism (TAM). As Sierra Club did not challenge the take or pay provision for the Hayden CSA in Docket No. UE 375, the Company's concurrently filed TAM, Staff does not recommend that the Commission disallow the costs of the minimum take provisions in the CSA.

Q. Does Staff make any adjustments to PacifiCorp's request?

A. Yes. As noted earlier in my testimony, Staff proposes to adjust the Oregon allocated net book value being requested by PacifiCorp for the SCRs at Hayden Units 1 and 2.

In response to Staff Data Request 750, the Company states that it is seeking cost recovery of the Oregon allocated net book value of the SCRs as of December 31, 2020.[154] However, in Staff's review, it became clear the PacifiCorp's calculation only accounts for depreciation through June 2019, and further does not account for the Oregon depreciable life of 2023.

Staff recommends the Commission reduce PacifiCorp's requested level of rate recovery for the Hayden Unit 1 and 2 SCRs by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to account for the Oregon depreciable

[154] Staff/2301, Soldavini/3. PacifiCorp response to Staff Data Request 750.

life, and to bring depreciation forward to December 31, 2020, as shown in the table below.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

1 **ISSUE 3, HUNTER UNIT 1 LOW NOX BURNERS AND BAGHOUSE**

2 **Q. Please summarize this issue.**

3 A. In this filing, PacifiCorp is requesting recovery of Low NOx Burners (LNB) and
4 Baghouse at Hunter Unit 1, placed into service in May 2014. PacifiCorp states
5 that this project was completed in order to meet compliance obligations
6 required by the Regional Haze Rule (Regional Haze) and Utah's Regional
7 Haze state implementation plan (SIP).[155]

8 **Q. Has the Commission previously considered the Hunter Unit 1 LNB and**
9 **Baghouse?**

10 A. Yes. In LC 57, the Commission declined to acknowledge the Hunter 1 LNB and
11 Baghouse investments because PacifiCorp failed to bring the investments to
12 the Commission in the 2011 IRP and at the time of the LC 57 proceeding the
13 investment decisions were substantially complete.

14 **Q. Did any party take issue with the Hunter Unit 1 LNB and Baghouse in**
15 **their Opening Testimony?**

16 A. Yes. AWEC recommends the Commission disallow the Company's request to
17 recover the costs of Hunter Unit 1 emission investments through rate base.
18 AWEC claims that had PacifiCorp used the appropriate depreciable life of 2029
19 in its analysis that would have reduced the value of the baghouse by $620
20 million, making the baghouse uneconomic in all but one scenario evaluated in
21 the Company's 2013 IRP.[156]

[155] PAC/800, Teply/37-43.
[156] AWEC/300, Kaufman/45.

AWEC also notes that without economic market transactions the baghouse investment was not economic, that the Company "did not explore any scenarios that involved tradeoffs across time or across generation units or plant,"[157] and that PacifiCorp did not consider the value of water rights when analyzing the investment which it may have been able to monetize.

Q. Does PacifiCorp agree that using a 2029 depreciable life would make the investment uneconomic?

A. No. PacifiCorp disagrees with AWEC's analysis, claiming that it is flawed and does not approximate how the economics would be impacted assuming a 2029 retirement date and recommends the Commission reject the analysis.

Q. Please explain AWEC's methodology in arriving at its conclusion that using a 2029 depreciable life would make the SCRs uneconomic.

A. AWEC's analysis applies an adjustment ratio of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to certain line items in Table V.3.4 in the Company's 2013 IRP.[158] This adjustment ratio attempts to account for the fact that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. AWEC's application of this adjustment ratio theoretically reduces the value of certain categories of cost to **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** of their stated value in Table V.3.4. In

[157] AWEC/300, Kaufman/46.
[158] AWEC/306, Kaufman/8.

addition, AWEC applies a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction to the value of DSM and entirely removes benefit of new resource capital/run-rate. Staff notes that this category has a PVRR(d) of ($562 million), meaning that AWEC's conclusion that a 2029 depreciable life would render the baghouse uneconomic rests mainly on the assumption that it would be appropriate to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Does Staff agree that AWEC's analysis is evidence that the Hunter Unit 1 baghouse was uneconomic?

A. No. While Staff understands that AWEC cannot perform a SO run to analyze the effects that using a 2029 depreciable life would have had on the PVRR(d), the analysis performed by AWEC is too simplistic to prove that the PVRR(d) of the investments at Hunter Unit 1 were imprudent.

AWEC's analysis relies largely on the assumption that it could **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** line item. It is unclear to Staff why this would be an appropriate assumption, and AWEC does not explain why this assumption was made. Further, simply applying an adjustment ratio is not a proper substitute for running the SO model, which accounts for many variables and constraints simultaneously over a period of many years.

Additionally, Staff agrees with the Company that AWEC appears to have only applied this adjustment ratio to some line items, rather than all categories of costs. When Staff recreated AWEC's table, applying the **[BEGIN**

1 **CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** adjustment ratio to all
2 line items in the table, the NPVRR(d) remains favorable to the investment;
3 however, as Staff noted above this analysis is not representative of what might
4 happen if PacifiCorp used a 2029 retirement date for Hunter Unit 1 in its 2013
5 IRP analysis.

6 **[BEGIN CONFIDENTIAL]**

[redacted]

7

8 **[END CONFIDENTIAL]**

9

Q. Does PacifiCorp agree that it did not explore alternative compliance scenarios involving tradeoffs across time or generation units or plants?

A. PacifiCorp does not specifically state that it *did* perform such analysis, but does appear to disagree with this claim noting that it examined various compliance scenarios including early retirement, and conversion to natural gas using its SO model.[159]

Q. Does PacifiCorp contest any of AWEC's other claims?

A. Yes, PacifiCorp agrees that it did not analyze the sensitivity of the Hunter Unit 1 investments to coal costs, but notes that coal prices are not generally as variable as gas or potential CO2 price fluctuations. PacifiCorp also notes that it did analyze the impacts of different natural gas and CO2 price scenarios which "provide a useful proxy for variable market prices".[160] The Company also disagrees with AWEC's assertion that it should have analyzed the effect of water rights associated with Hunter Unit 1 stating that it "does not own any actual water rights associated with the Hunter plant"[161] and that the water supply for the Hunter plant comes from "share ownership in local irrigation companies…and contractual rights to use storage from two nearby reservoirs" which could not be redirected toward Lake Powell without consent from the irrigation companies and the State of Utah.[162]

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[159] PAC/2300, Link/50.
[160] *Ibid.*
[161] PAC/2600, Ralston/26.
[162] *Ibid.*

Q. What is Staff's recommendation?

A. Staff recommends that the Commission find the costs associated with the Hunter Unit 1 Low NOx and baghouse were prudent and be allowed into rate base as described below. Though Staff supports AWEC's claim that the Company could have performed more analysis on regarding the sensitivity to market prices, coal costs, and tradeoffs between generation units, there is insufficient evidence on the record to support the idea that such analysis would, or could, have resulted in a different outcome.

Q. Does Staff propose an adjustment to rate base to account for the depreciable life?

A. Yes. Similar to Staff's proposed adjustments for the Jim Bridger and Hayden SCRs, Staff proposes a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction to the Oregon allocated net book value of plant associated with the Hunter low NOx burners and baghouse, to comport with the Oregon depreciable life of the Hunter 2029, and bring the balance forward to December 31, 2020. This results in a recommended Oregon allocated net book value for the Hunter low NOx burners and baghouse of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as opposed to the Company's proposed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

1 **[BEGIN CONFIDENTIAL]**

[redacted]

2
3 **[END CONFIDENTIAL]**

ISSUE 4, CRAIG UNIT 2 SCR

Q. Please summarize this issue.

A. In this filing, PacifiCorp is seeking to recover the costs associated with the installation of an SCR system at Craig Unit 2. The Craig facility is a three-unit coal-fired electrical generating facility located in Moffat County, Colorado. PacifiCorp is a joint owner of Units 1-2, and owns 19.28 percent of the units. Unit 3 is solely owned by Tri-State Generation and Transmission Association, Inc. (Tri-State). All three Craig units are operated by Tri-State.[163]

Q. Why was an SCR system installed at Craig Unit 2?

A. As outlined by PacifiCorp in its opening testimony, the Company notes that the Craig Unit 2 SCR was required by the Clean Air Act Regional Haze Rules and the Colorado Regional Haze SIP, which required the SCR be installed by January 30, 2018. The Craig Unit 2 SCR system was placed in service on December 2017, and the total Oregon allocated costs of the project is equal to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Has the Craig Unit 2 SCR system been reviewed by the Commission before?

A. Yes. In the 2013 IRP, the Commission did not acknowledge Craig Unit 2 SCR as it was not an action item in the IRP. The Commission required PacifiCorp to

[163] PAC/800, Teply/45.

hold a confidential technical workshop to review existing analysis on Craig and Hayden investments within three months.[164]

Q. Did PacifiCorp present its existing analysis to the Commission as ordered in LC 57?

A. Yes. The Company held a technical workshop for the Commission on August 6, 2014. A copy of the confidential presentation has already been included in the record of this case in Exhibit Sierra Club/121.

Q. Did any parties recommend a prudence disallowance for the Craig SCR in their opening testimony?

A. No, no party recommended the Commission find the Craig SCR investment imprudent in its opening testimony.

Q. Is Staff proposing an adjustment?

A. Staff is not proposing a prudence disallowance or management adjustment for the Craig Unit 2 SCR installation. Staff does however propose an adjustment to the Oregon allocated net book value of the Craig Unit 2 SCR.

Staff recommends a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction to the Oregon allocated net book value of the plant associated with the Craig Unit 2 SCR. This results in an Oregon allocated net book value of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** instead of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Oregon allocated net book value as proposed by

[164] LC 57, Order No. 14-252.

1 the Company in its response to Staff Data Request 750, and brings forward
2 the balance to December 31, 2020.
3 **[BEGIN CONFIDENTIAL]**
4 [redacted]
5 **[END CONFIDENTIAL]**

ISSUE 5, OTHER REVENUE

Q. What was Staff's recommendation for Other Revenue?

A. Staff's opening testimony recommended an adjustment to Miscellaneous Revenue of $435,435 to escalate the revenues in FERC Accounts 450 (Forfeited Discounts & Interest), 453 (Water Sales), and (454 Rent of Electric Property) to account for potential increases through the test year as the number of customers from which the Company can collect these revenues is also projected to increase.

Q. Does the Company agree with Staff's recommendation?

A. No. The Company states that it proposed no adjustments to FERC Accounts 450, 453, and 454 as there were no known or measurable changes in the preparation of the GRC and recommends that the Commission reject Staff's adjustment.[165]

The Company agrees that there may be a correlation between the number of customers and the revenues in FERC Account 453, but states that since 2017 there has been "a downward trend in these revenues, dropping from $4.6 million in 2017 to $4.2 million in the Base Period."[166] The Company further notes that because the Company has suspended all late payment charges as of March 31 due to the impacts of COVID-19, it would be inappropriate to assume an escalation of these revenues in 2020.

[165] PAC/3100, McCoy/6.
[166] PAC/3100, McCoy/5.

1 PacifiCorp further notes that there is no correlation between retail customers
2 and revenues in FERC Accounts 453 and 454, and states that because the
3 levels of revenue in these accounts have been "relatively flat over the last few
4 years" there is no basis to inflate them for the Test Period.[167]

5 **Q. How does Staff respond?**

6 A. After reviewing the Company's response, Staff is willing to accept the
7 Company's position as reasonable at this time, as the levels that PacifiCorp
8 has included for these three accounts in the test year is greater than the five
9 year average for each. Staff notes that another driving factor in Staff's
10 willingness to accept the Company's position is the unknown impact on the
11 Company's level of other revenue of the COVID-19 pandemic.

12 **Q. What is Staff's recommendation?**

13 A. Based on the Company's response to Staff's opening testimony, and the fact
14 there are still unknown effects of the COVID-19 pandemic on the Company's
15 revenues associated with FERC Accounts 450, 453, and 454, Staff
16 recommends that the Commission approve the Company's proposed level of
17 Test Year Other Revenue.

[167] PAC/3100, McCoy/6.

1 **ISSUE 6, RELIABILITY COORDINATOR FEE**

2 **Q. Please summarize Staff's recommendation on this issue.**

3 A. In Opening Testimony, Staff recommended an Oregon allocated expense
4 reduction of approximately $579,000 due to a decrease reliability coordinator
5 fees in 2020 compared to the Base Period associated with the Company's
6 change from PEAK Reliability to the California System Operator (CAISO) as
7 the reliability coordinator.

8 **Q. Has the Company agreed to update its reliability coordinator fee in this**
9 **case?**

10 A. Yes. The Company has agreed to Staff's proposal with one modification. The
11 Company proposes to use IHS escalators which the Company notes are
12 industry specific, as opposed to the all-urban CPI used in Staff's calculation.
13 This modification results in an expense reduction of $575,553 on an Oregon
14 allocated basis versus the $579,216 adjustment proposed by Staff.[168]

15 **Q. Does Staff support the Company's modification?**

16 A. Yes. Staff can support the Company's modification to Staff's methodology for
17 this adjustment, and recommends the Commission approve the $575,553
18 expense reduction to FERC Account 560 to account for the Company's
19 change in reliability coordinator. Staff notes it is not broadly accepting the
20 Company's proposal to use IHS escalators, but in this particular instance the
21 reliability coordinator fee is directly tied to CAISO, and allocated based on
22 industry specific factors such as annual load and generation of CAISO market

[168] PAC/3102, McCoy/133.

1 participants.[169] Therefore, Staff approves of the Company's proposal to use
2 industry specific escalations for this particular adjustment.

[169] Staff/2302, Soldavini/1. PacifiCorp response to Staff Data Request 277.

ISSUE 7, CUSTODY FEES

Q. What was Staff's recommendation in Opening Testimony regarding custody fees?

A. As shown in the table below, Staff recommended a ($60,476) Oregon allocated adjustment to PacifiCorp's Custody Fees in the Test Year. Staff's recommendation accounts for changes proposed in Docket No. UI 435, where the Company requested approval of an affiliate transaction with Bank of New York Mellon Trust Company, N.A. (BNY Mellon), stating its intention "to enter into up to seven new Trust Agreements and/or Custodian Agreements with BNY Mellon as trustee."[170]

Fee	*Current*	*BNY Mellon*
Consolidated Pension Trust (Total BHE)	$ 850,495	$ 314,341
PacifiCorp Share of Pension Trust	$ 283,497	$ 104,780
PacifiCorp Union VEBA	$ 85,251	$ 55,607
PacifiCorp VEBA	$ 5,785	$ 2,637
PacifiCorp Executive Trust	$ 27,738	$ 34,496
PacifiCorp Bridger	$ 44,218	$ 24,804
PacifiCorp NDT	$ -	$ 1,024
PacifiCorp Foundation	$ 4,511	$ 5,436
Total PAC Fees	**$ 451,000**	**$ 228,784**

Staff Total Company Adjustment	$(222,216.43)
OR Allocated Adjustment	$(60,476.87)

Q. Does PacifiCorp agree with Staff's adjustment?

A. Yes. PacifiCorp apparently accepts that it should update the custody fees in this filing, but notes that the way custody fees flow through the Company's

[170] Docket No. UI 435, PacifiCorp Initial Application, page 1.

1 expense is somewhat complicated, as they are not recorded in one account.[171]
2 PacifiCorp notes that for simplicity of presentation the Company has made
3 Staff's recommended adjustment to FERC Account 921, Office Supplies and
4 Expenses. Staff notes that the Company's adjustment reduces expense by
5 approximately $71,527.[172]

6 **Q. Does Staff support this application?**

7 A. Yes. Staff supports the Company's decision to make an adjustment to FERC
8 Account 921 to implement Staff's proposal.

9 **Q. Does this conclude your testimony?**

10 A. Yes.

[171] PAC/3100, McCoy/8.
[172] PAC/3102, McCoy/51.

CASE: UE 374
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2301

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

OPUC Data Request 277

Regarding the recent dissolution of the reliability coordinator, Peak Reliability, and the transition to CAISO as a reliability coordinator, please respond to the following:

a. What is the cost of service rate difference between PEAK Reliability RC services and CAISO RC services for PacifiCorp?
b. Please provide the level of reliability coordinator expense for each of the following years: 2015, 2016, 2017, 2018, and 2019.
c. Please provide the level of reliability coordinator expense included in the Test Year. Please explain how the Company estimated the Test Year value and include any relevant workpapers.
d. How are the costs of CAISO RC services allocated between PacifiCorp's jurisdictions? Please provide the amount allocated to each state in the Test Year.
e. Do any of PacifiCorp's affiliates use CAISO RC services or benefit from PacifiCorp's use of CAISO as its RC? If so, is any portion of these costs shared between the Company and its affiliates?

Response to OPUC Data Request 277

a. The cost of service under PEAK Reliability (PEAK) was based on PacifiCorp paying a portion of PEAK's overall budget. PacifiCorp's relative share was basically PacifiCorp's annual load relative to other members load for a given year. The California Independent System Operator (CAISO) will calculate the annual Reliability Coordinator funding requirement each January and then allocate to each balancing area (BA), generator, and transmission operating provider (TOP) CAISO anticipates taking this service based on: (1) the annual Net Energy for Load (NEL) megawatt-hours (MWh) for all BAs with load and TOPs and (2) the annual Net Generation MWh for all generators connected to generation-only BAs. The effective rate charged for 2020 was 0.0278 MWh and a total charge of $1,986,251.76 covering 2020 and $321,304.76 covering 2019. The current projection is a fee lower than PEAK but is subject to change given market participants and CAISO budget.

b. Reliability Coordinator expenses:

Year	Vendor	Amount	Timeframe
2015	PEAK Reliability RC	$3,635,241	1/1/15 - 12/31/15
2016	PEAK Reliability RC	$3,899,622	1/1/16 - 12/31/16
2017	PEAK Reliability RC	$3,873,262	1/1/17 - 12/31/17
2018	PEAK Reliability RC	$3,893,221	1/1/18 - 12/31/18
2019	PEAK Reliability RC	$5,059,884	1/1/19 - 12/31/19
2020	CAISO RC	$2,307,557	1/1/20 - 12/31/20
Base Year	PEAK Reliability RC	$4,476,552	7/1/2018 - 6/30/19

c. Please see Attachment OPUC 277.

d. Reliability Coordinator services are allocated on the System Generation allocation factor. Please see Attachment OPUC 277 for the state allocations.

e. Yes, PacifiCorp's Affiliate Nevada Energy (NVE) is also utilizing CAISO for Reliability Coordinator services. As a result NVE is also charged based on the methodology described in response to question A. Neither NVE nor PacifiCorp receive a direct benefit from each other for this service. More participants taking this service from CAISO spreads the overall cost and lowers the rate.

OPUC Data Request 750

Please refer to PAC/800, Teply/24.

(a) For each emissions control retrofit project, please confirm whether PacifiCorp is seeking to include in rates the current net book value of the original investments, or some other amount. Please explain.

i. Please provide the gross book value, net book value as of 12/31/2020, and the amount of cost recovery that PacifiCorp is seeking in this general rate case on both a total company and Oregon allocated basis.

ii. Please provide work papers detailing how these amounts were calculated based on the original project costs, depreciation rates, etc.

1st Revised Response to OPUC Data Request 750

This response replaces, in its entirety, the Company's original response dated July 9, 2020, which inadvertently identified the attachment as non-confidential. No other changes have been made to this revised response other than the confidential designation of the attachment.

(a) PacifiCorp is seeking to recover in rates the remaining net book value of the emission control projects as of December 31, 2020.

i. Please refer to Attachment OPUC 750 for the gross plant value and net book value based on Oregon lives as of December 31, 2020, and the Oregon allocated amounts. Cost recovery is equal to the annual depreciation expense for these assets.

ii. Refer to Confidential Attachment OPUC 750 1st Revised.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 751

Jim Bridger SCRs - Please refer to PAC/2300, Link/8. Please provide evidence to support the statement that "[t]he Company also verified that none of its third-party forecast providers had projected increases in carbon costs in response to President Obama's June 2013 Presidential Memorandum regarding carbon emissions."

Response to OPUC Data Request 751

Please refer to Confidential Attachment OPUC 751 for the national carbon dioxide (CO_2) price forecasts, to which the Company had access, as published by third-party forecasting services in spring 2013 and fall 2013. The spring forecasts predate President Obama's June 2013 Presidential Memorandum, while the fall 2013 forecasts were produced four months to six months after the Presidential Memorandum. There were virtually no material changes in the constant-dollar CO_2 price forecasts between spring 2013 and fall 2013 outlooks. Note: the confidential attachment referenced above provides the third-party information that is in the Company's possession. The provided third-party information is proprietary and is provided subject to the terms and conditions of the protective order/confidentiality agreement in this proceeding.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 752

Jim Bridger SCRs - Please refer to PAC/2300, Link/16, at line 11 through 18. Please provide the referenced sensitivity study and any associated work papers.

Response to OPUC Data Request 752

Please refer to the Company's response to Sierra Club Data Request 8.2 subpart (m), and Sierra Club Data Request 7.3.

OPUC Data Request 753

Please refer to PAC/2600, Ralston/7, at line 9 through 11. Please explain what PacifiCorp considers "significant cost events" that would trigger the Company to prepare a new long-term fueling plan outside of its typical two year cycle.

Response to OPUC Data Request 753

"Significant cost events" that would trigger the Company to prepare a new long-term fueling plan outside of the two-year integrated resource plan (IRP) cycle would be events that substantially change long-term generation requirements or substantial changes in costs at the Jim Bridger plant.

OPUC Data Request 754

Please refer to PAC/2500, Owen/16 at line 10 through 19. Please provide any work papers or evidence to support the statement that "[b]ased on information from the competitive market bids for the Naughton Unit 3 natural gas conversion EPC contract, the Company knew by January 2014 that implementation costs for that project were significantly higher…than originally anticipated."

Response to OPUC Data Request 754

Please refer to the Company's response to Sierra Club Data Request 8.3, subparts (a) through (c). Some of the information responsive to this request is commercially sensitive third-party information and highly confidential. The Company requests special handling. Please contact Matt McVee at (503) 813-5585 to make arrangements for review.

OPUC Data Request 755

Please refer to PAC/2600, Ralston/29. Please provide evidence to support PacifiCorp's statement that on October 27, 2010 PacifiCorp filed a challenge to Colorado's BART determination and that PacifiCorp's challenge was ultimately unsuccessful.

Response to OPUC Data Request 755

Please refer to Attachment OPUC 755.

Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado

Colorado Air Pollution Control Division

<u>Revised Regional Haze Plan</u>
Air Quality Control Commission, approved 01/07/2011

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Preface/Disclaimer

The following document contains Colorado"s State Implementation Plan for Regional Haze. Unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described. Many of these controls are neither being submitted to EPA for approval nor being incorporated into the SIP as federally enforceable measures and are mentioned only as examples or references to Colorado air quality programs.

In developing and updating its Long Term Strategy (LTS) for reasonable progress, the State of Colorado takes into account the visibility impacts of several ongoing state programs that are not federally enforceable. These include statewide Colorado requirements applying to open burning, wildland fire smoke management, and renewable energy.

References in this SIP revision to such programs are intended to provide information that Colorado considers in developing its LTS and in its reasonable progress process. These programs are neither being submitted for EPA approval, nor for incorporation into the SIP by reference, nor are they intended to be federally enforceable. The Air Quality Control Commission Rules that govern them implement Colorado"s programs and are not federally required. The state is precluded from submitting such programs for incorporation into this SIP by 25-7-105.1, C.R.S.

The following dates reflect actions by the Air Quality Control Commission associated with Colorado State Implementation Plan for Regional Haze:

Regional Haze Plan	Approval Date
Original	12/21/2007
First Revision	12/19/2008
Second Revision (Fully Replaces All Previous RH Plans)	01/07/2011

Chapter 1 Overview

1.1 Introduction

The Clean Air Act (CAA) defines the general concept of protecting visibility in each of the 156 Mandatory Class I Federal Areas across the nation. Section 169A from the 1977 CAA set forth the following national visibility goal:

> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution."

The federal visibility regulations (40 CFR Part 51 Subpart P – Visibility Protection 51.300 - 309) detail a two-phased process to determine existing impairment in each of the Class I areas; how to remedy such impairment; and how to establish goals to restore visibility to „natural conditions" by the year 2064. The federal regulations require states to prepare a State Implementation Plan (SIP) to:

- include a monitoring strategy
- address existing impairment from major stationary facilities (Reasonably Attributable Visibility Impairment)
- prevent future impairment from proposed facilities
- address Best Available Retrofit Technology (BART) for certain stationary sources
- consider other major sources of visibility impairment
- calculate baseline current and natural visibility conditions
- consult with the Federal Land Managers (FLMs) in the development or change to the SIP
- develop a long-term strategy to address issues facing the state
- set and achieve reasonable progress goals for each Class I area
- review the SIP every five years

Phase 1 of the visibility program, also known as Reasonably Attributable Visibility Impairment (RAVI), addresses impacts in Class I areas by establishing a process to evaluate source specific visibility impacts, or *plume blight*, from individual sources or small groups of sources. Part of that process relates to evaluation of sources prior to construction through the Prevention of Significant Deterioration (PSD) permit program looking at major stationary sources. The plume blight part of the Phase 1 program also allows for the evaluation, and possible control, of reasonably attributable impairment from existing sources.

Section 169B was added to the Clean Air Act Amendments of 1990 to address Regional Haze. Since Regional Haze and visibility problems do not respect state and tribal boundaries, the amendments authorized EPA to establish visibility transport regions as a way to combat regional haze.

Phase 2 of the visibility program addresses Regional Haze. This form of visibility impairment focuses on overall decreases in visual range, clarity, color, and ability to discern texture and details in Class I areas. The responsible air pollutants can be

generated in the local vicinity or carried by the wind often many hundreds or even thousands of miles from where they originated. For technical and legal reasons the second part of the visibility program was not implemented in regulation until 1999. In 1999 the EPA finalized the Regional Haze Rule (RHR) requiring States to adopt a State Implementation Plans (SIPs) to address this other aspect of visibility impairment in the Class I areas. Under current rules the Regional Haze SIP were to be submitted to the EPA by December 31st, 2007. Colorado adopted key components of the Regional Haze SIP in 2007 and 2008 which were submitted to EPA in 2008 and 2009, respectively. EPA subsequently noted deficiencies in the BART determination and Reasonable Further Progress elements, as well as other, more minor issues. Colorado has proceeded to take steps to remedy these alleged deficiencies. This SIP addresses EPA"s concerns. Updates to the BART evaluations and Reasonable Further Progress analyses constitute the major revisions to this 2010 plan. In addition, revisions to other chapters have been made to update emissions and monitoring data and descriptions of program changes impacting emissions regulations favoring improved visibility in the State.

The Regional Haze Rule envisions a long period, covered by several planning phases, to ultimately meet the congressionally established National Visibility Goal targeted to be met in 2064. Thus, the approach taken by Colorado, and other states, in preparing the plan is to set this initial planning period (2007-2018) as the "foundational plan" for the subsequent planning periods. This is an important concept when considering the nature of this SIP revision as compared to a SIP revision developed to address a nonattainment condition. The nonattainment plan must demonstrate necessary measures are implemented to meet the NAAQS by a specific time. On the other hand, the Regional Haze SIP must, among other things, set a Reasonable Progress Goal for each Class I area to protect the best days and to improve visibility on the worst days during the applicable time period for this SIP (2007-2018).

Colorado developed, and EPA approved, a SIP for the first Phase 1 of the visibility program. This Plan updates Phase 1 as well as establishing Phase 2 of the program, Regional Haze. The two key requirements of the Regional Haze program are:

- Improve visibility for the most impaired days, and
- Ensure no degradation in visibility for the least impaired days.

Though national visibility goals are targeted to be achieved by the year 2064,this plan is designed to meet the two requirements stated above for the period ending in 2018 (the first planning period in the federal rule), while also establishing enforceable controls to that will help to address the long term goal.

This SIP is intended to meet the requirements of EPA"s Regional Haze rules that were adopted to comply with requirements set forth in the Clean Air Act. Elements of this Plan address the core requirements pursuant to 40 CFR 51.308(d) and the Best Available Retrofit Technology (BART) components of 40 CFR 50.308(e). In addition, this SIP addresses Regional Planning, State/Tribe and Federal Land Manager coordination, and contains a commitment to provide Plan revisions and adequacy determinations.

1.2 Visibility Impairment

Most visibility impairment occurs when pollution in the form of small particles scatter or absorb light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources can include windblown dust and smoke from wildfires. Anthropogenic sources can include motor vehicles and other transportation sources, electric utility and industrial fuel burning, minerals, oil and gas extraction and processing and manufacturing operations. More pollutants mean more absorption and scattering of light which reduces the clarity and color of a scene. Some types of particles such as sulfates scatter more light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye and the object may be a single viewing target or a scene.

In the 156 Class I areas across the country, visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from an average of 140 miles to 35-90 miles. Colorado has some of the best visibility in the West but also has a number of areas where visibility is impaired due to a variety of sources. This SIP is designed to address regional haze requirements for the twelve mandatory Federal Class I areas in Colorado.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are transported many miles from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and other environmental damage. Exposure to increased levels of very small particles in the air has been linked with increased respiratory illness, decreased lung function, and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers, and streams less suitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings or other natural and manmade structures.

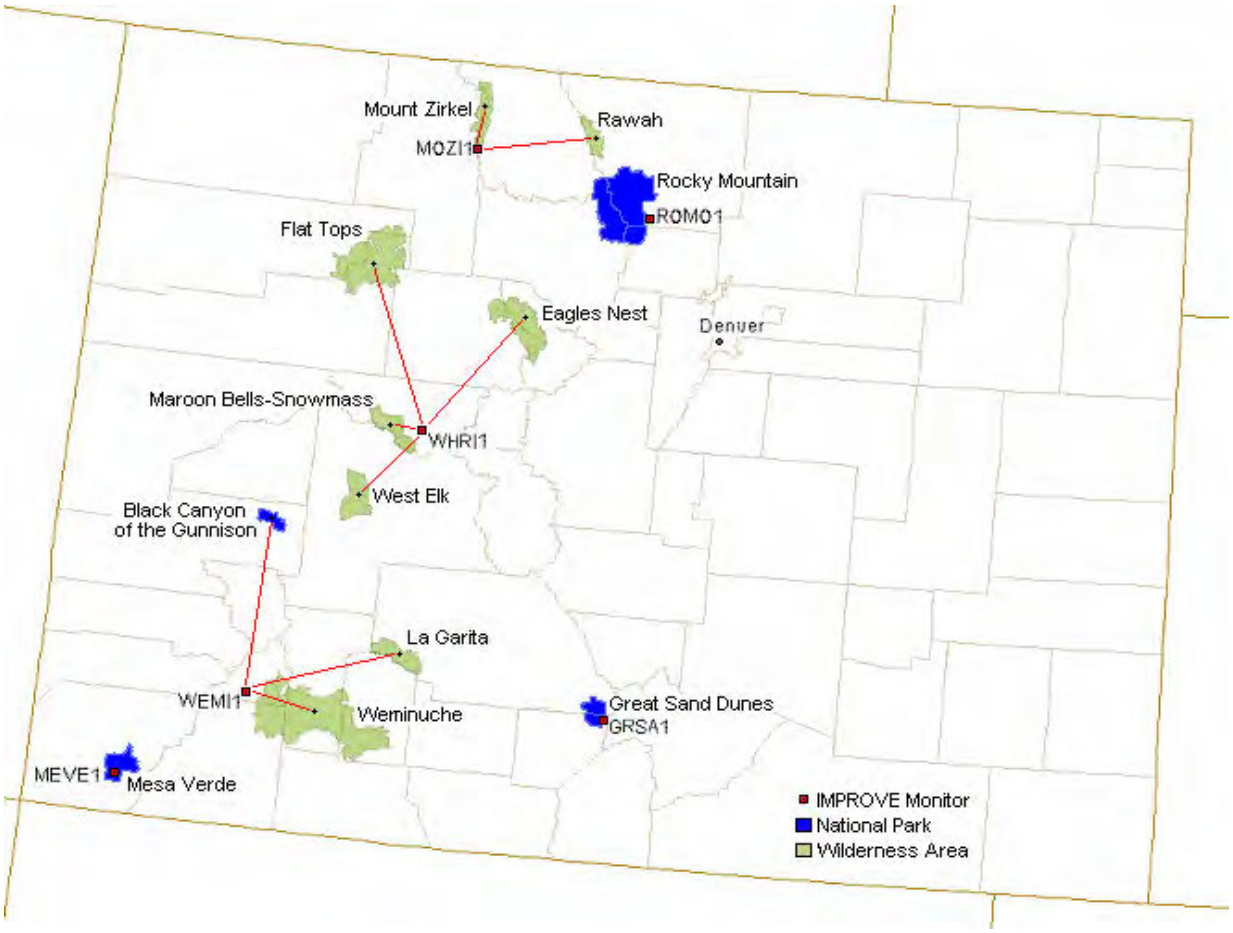
1.3 Description of Colorado's Class I Areas

There are 12 Mandatory Federal Class I Areas in the State of Colorado:

Black Canyon of the Gunnison National Park
Eagles Nest Wilderness Area
Flat Tops Wilderness Area
Great Sand Dunes National Park
La Garita Wilderness Area
Maroon Bells-Snowmass Wilderness Area
Mesa Verde National Park
Mount Zirkel Wilderness Area
Rawah Wilderness Area
Rocky Mountain National Park
Weminuche Wilderness Area
West Elk Wilderness Area

A detailed description of each of these areas, along with photographs, summaries of monitoring data containing an overview of current visibility conditions and sources of pollution in each area, is contained in individual Technical Support Documents (TSDs) for this plan (see list in Chapter 10). Each Class I area has been designated as impaired for visual air quality by the Federal Land Manager responsible for that area. Under the federal visibility regulations, the Colorado visibility SIP needs to address the visibility status of and control programs specific to each area. Figure 1-1 shows the location of these areas and the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring site that measures particulate air pollution representative of each Class I area.

Figure 1-1 Colorado Class I Areas and IMPROVE Monitor Locations



1.4 Programs to Address Visibility Impairment

Colorado adopted a Phase 1 visibility SIP to address the PSD permitting, source specific haze, and plume blight aspects of visibility in 1987. The most recent plan update was approved by the EPA in December 2006.

As stated in the preface to this Plan, unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described and are neither being submitted to EPA

for approval nor being incorporated into the SIP as Federally enforceable measures. This comprehensive visibility plan, which now contains both Phase 1 and Phase 2 visibility requirements, addresses all aspects of Colorado"s visibility improvement program. Colorado has numerous emission control programs to improve and protect visibility in Class I areas. In addition to the traditional Title V, New Source Performance Standards, Maximum Achievable Control Technology and new source review permitting programs for stationary sources, Colorado also has Statewide emission control requirements for oil and gas sources, open burning, wildland fire, smoke management, automobile emissions for Front Range communities, and residential woodburning, as well as PM10 nonattainment/maintenance area requirements, dust suppression for construction areas and unpaved roads and renewable energy requirements.

Colorado adopted legislation to address renewable energy by establishing long-term energy production goals. This program is expected to reduce future expected and real emissions from coal-fired power plants. This renewable energy measure was considered a key feature of the Grand Canyon Visibility Transport Commission's recommendations. Although the Colorado renewable energy program was not specifically adopted to meet regional haze requirements, emissions from fossil-fuel fired electricity generation are avoided in the future.

Colorado is also setting emission limits (as part of this plan) for those sources subject to Best Available Retrofit Technology (BART) requirements of Phase 2 of the visibility regulations for Regional Haze (described in detail in Chapter 6 of this plan). To comply with these BART limits sources subject to BART are required to install

and operate BART as expeditiously as practicable, but not later than 5 years after EPA"s approval of the implementation plan revision.

As such, this Plan documents those programs, regulations, processes and controls deemed appropriate as measures to reduce regional haze and protect good visibility in the State toward meeting the 2018 and 2064 goals established in EPA regulations and the CAA.

1.5 Reasonable Progress Towards the 2064 Visibility Goals

As described in detail in Chapters 8 and 9 of this plan, reasonable progress goals for each Class I area have been established. The Division has worked with the Western Regional Air Partnership (WRAP) and with the WRAP"s ongoing modeling program to establish and refine Reasonable Progress Goals (RPGs) for Colorado Class I Areas.

Technical analyses described in this Plan demonstrate emissions both inside and outside of Colorado have an appreciable impact on the State"s Class I areas. Emission controls from many sources outside Colorado are reflected in emission inventory and modeling scenarios for future cases as detailed in the WRAP 2018 PRP18b control case. Progress toward the 2064 goal is determined based on emission control scenarios described in the WRAP inventory documentation plus the state"s BART and reasonable progress determinations.

Chapter 2 Plan Development and Consultation

This chapter discusses the process Colorado participated in to address consultation requirements with the federal land managers, tribes and other states in the Western Regional Air Partnership (WRAP) during the development of this Plan and future commitments for consultation.

Colorado has been a participating member of the WRAP since its inception. The WRAP completed a long-term strategic plan in 2003.[1] The Strategic Plan provides the overall schedule and objectives of the annual work plans and may be revised as appropriate. Among other things, the Strategic Plan (1) identifies major products and milestones; (2) serves as an instrument of coordination; (3) provides the direction and transparency needed to foster stakeholder participation and consensus-based decision making, which are key features of the WRAP process; and (4) provides guidance to the individual plans of WRAP forums and committees.

Much of the WRAP"s effort is focused on regional technical analysis serving as the basis for developing strategies to meet the RHR requirement to demonstrate reasonable progress towards natural visibility conditions in Class I national parks and wilderness areas. This includes the compilation of emission inventories, air quality modeling, and ambient monitoring and data analysis. The WRAP is committed to using the most recent and scientifically acceptable data and methods. The WRAP does not sponsor basic research, but WRAP committees and forums interact with the research community to refine and incorporate the best available tools and information pertaining to western haze.

2.1 Consultation with Federal Land Managers (FLM)

Section 51.308(i) requires coordination between states and the Federal Land Managers (FLMs). Colorado has provided agency contacts to the Federal Land Managers as required. In development of this Plan, the Federal Land Managers were consulted in accordance with the provisions of 51.308(i)(2). Specifically, the rule requires the State to provide the Federal Land Manager with an opportunity for consultation, in person, and at least 60 days prior to holding any public hearing on an implementation plan or plan revision for regional haze. This consultation must include the opportunity for the affected Federal Land Managers to discuss their assessment of impairment of visibility in any mandatory Class I Federal area and recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment. The State must include a description of how it addressed any comments provided by the Federal Land Managers. Finally, the plan or revision must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.

[1] See http://www.wrapair.org/forums/sp/docs.html

Colorado participated in the WRAP to develop many elements of the SIP. The WRAP represents a conglomeration of stakeholder representing FLMs, industry, States, Tribes environmental groups and the general public. Through participation in this process, a significant portion of the consultation process with FLMs and other states has been met. In the WRAP process these stakeholders participated in various forums to help develop a coordinated emissions inventory and analysis of the impacts sources have on regional haze in the west. Coordination and evaluation of monitoring data and modeling processes were also overseen by WRAP participants. Through these coordinated technical evaluations, a regional haze-oriented evaluation of Colorado's Class I areas was constructed. Summaries of this information are available in the technical support documents of this Plan.

Public meetings were held at the Colorado Air Quality Control Commission in 2007 and 2008 to provide a comprehensive review of the technical basis for the Plan. Following these meetings, additional meetings were held with the FLMs directly concerning each of the affected Class I areas and the development of the SIP. Prior to the requests for a public hearing on the Regional Haze SIP in August and September 2010, the Division again met with the FLMs to review additions, corrections and changes to the SIP made to address both FLM concerns over the analysis of additional controls on sources not subject to BART and the completion of BART analyses occurring after the 2008 hearings (these new analyses and inventories are reflected later on in this SIP document).

The FLMs have provided comments to the Division regarding proposed regional haze determinations over the course of several years in 2007 and 2008, and again in 2010. The state has carefully considered these comments and has made changes to many of its proposed determinations based in part on these comments. For example, the state has deleted its regulatory prohibition on consideration of post-combustion controls as part of the BART analysis. The state also revisited its earlier BART determinations that relied in some respects on EPA"s so called „presumptive" emission limits for NOx and SO2, and in turn conducted robust facility-specific 5 and 4 factor analyses under BART and RP.

Most recently, the FLMs formally commented on the revised, proposed BART and RP determinations, as well as reasonable progress goals, in November and December 2010. The National Park Service, the Fish and Wildlife Service and the U.S. Forest Service provided support for the modeling approach used by the state in the BART determinations, complimented the state on thorough 5 and 4 factor analyses, clear criteria, area source evaluations, and comprehensive/improved BART and RP determinations, and presented recommendations for cost/emission limit re-evaluations. The state appreciates the supportive input from the FLMs, especially in the areas of modeling and the establishment of the RPGs. The state gave serious consideration to the recent recommendations for revising cost estimates and lowering emission limits, but the comments ultimately did not alter the state"s conclusions and resulting proposals.

Regarding the costs of control, the FLMs provided numerous recommendations for revising BART and RP control costs. The state notes that there is no regulatory approach for determining costs of controls. The state considered the relevant factors

for BART and RP determinations as set forth in the statute, the regulations and guidance, and consistent with the discretion expressly afforded to states under the statute and regulations. The state received detailed source-specific information for the facilities evaluated, checked this information using many different resources, and made adjustments/normalization when appropriate. The state employed engineering judgment and discretion when preparing BART and RP determinations, and found that the relevant present day and estimated future costs generally fell within the range of typical control costs nationwide. The state considered broader cost survey information to be relevant, and considered such information but did not find it dispositive; the state was informed more on facility-specific information as provided to the state to support its analyses and determinations. For most facilities even if different cost assumptions were employed or were re-assessed, expected visibility from the relevant control did not satisfy the state"s guidance criteria for visibility improvement, and thus would not change the state"s determination. Further, the state finds metrics like dollar per kilowatt hours or dollar per deciview of improvement of limited utility in considering the 5 or 4 factors, and opted to use its own more straightforward approach to balance and weigh costs of control and related visibility improvement. The costs used by the state were determined to be appropriate and reasonable, were balanced with the state"s consideration of related visibility improvement, and further revisions based on FLM comments were not incorporated. The resulting emissions reductions from the state"s BART and RP determinations for NOx and SO2 are significant and will benefit Class I Areas.

Regarding CALPUFF modeling, the FLMs provided support for the state"s BART and RP modeling efforts, including the modeling protocol and methodologies. However, the state respectfully disagrees with the FLMs recommendations to cumulate visibility improvement impacts from emission controls across multiple Class I Areas. It is the state"s position that the approach employed is consistent with a straightforward application of the regional haze regulation, and that the approach suggested by the FLMs, while an option that could be considered, as a general rule is not appropriate. The Commission in making its determinations on certain BART sources was aware that emissions reductions would have some level of visibility improvement in other than the most impacted Class I Area. The CALPUFF modeling output files have been and continue to be available to the FLMs or to the public to perform such analyses.

Regarding BART and RP emission limits, the FLMs provided numerous comments to the state, identifying opportunities for tightening most of the proposed limits. The state notes that there is no regulatory formula for establishing limits in the Regional Haze rule and the state applied professional judgment and utilized appropriate and delegated discretion in establishing appropriate emission limits. The stringency of the limits are tight enough to satisfy BART and RP requirements, but are not operationally unachievable. The emission limits fall within the range of limits adopted nationwide and were developed considering the requirements of the Regional Haze rule and related guidance.

Thus, between the WRAP, AQCC and individual meetings with the FLMs, the State has met the FLM consultation requirements.

Colorado commits to continued coordination and consultation with the Federal Land Managers during the development of future progress reports and Plan revisions, in accordance with the requirements of 51.308(i)(4).

2.2 Collaboration with Tribes

The Southern Ute Tribal lands in the southwest corner of Colorado are adjacent to Mesa Verde National Park, one of Colorado's Class I areas. As described above, Colorado participated in the collaborative WRAP process where Tribes were represented in all levels of the process. In addition, the Colorado Air Quality Control Commission had joint meetings with the Tribal Air Quality Council concerning regulatory and other processes related to air quality control and planning. The Southern Ute Tribe has numerous major and minor sources operating on their lands. Major source permitting is coordinated through a joint agreement with EPA Region IX. Minor sources on Tribal lands in Colorado are subject to the jurisdiction of the Tribes and this Plan contains no regulatory provisions for sources on Southern Ute lands in Colorado. The Tribes have the opportunity to develop Tribal Implementation Plans to address sources of pollution impacting visibility in their area.

2.3 Consultation with Other States

Pursuant to 40 CFR Section 51.308(d)(iv), Colorado consulted with other states during ongoing participation in the Regional Planning Organization, the Western Regional Air Partnership (WRAP), in developing the SIP. The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. The WRAP is administered jointly by the Western Governors' Association and the National Tribal Environmental Council. WRAP activities are conducted by a network of committees and forums composed of WRAP members and stakeholders who represent a wide range of viewpoints. The WRAP recognizes that residents have the most to gain from improved visibility and that many solutions are best implemented at the local, state, tribal or regional level with public participation. Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming have agreed to work together to address regional haze in the western United States. Colorado held specific discussions with states that have a primary impact on Colorado Class I areas. These include California, Utah, New Mexico and Arizona regarding the impacts from sources in these states on Colorado Class I areas.

The major amount of state consultation in the development of SIPs was through the Implementation Work Group (IWG) of the WRAP. Colorado participated in the IWG which took the products of the WRAP technical analysis and consultation process discussed above and developed a process for establishing reasonable progress goals in the western Class I areas. A description of that process is discussed in Chapter 8 -- Reasonable Progress Section of the State SIP.

Through the WRAP consultation process Colorado has reviewed and analyzed contributions from other states that reasonably may cause or contribute to visibility impairment in Colorado"s Class I areas. While emissions from sources outside of Colorado have resulted in a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, most of these emissions are beyond the control of any state in the regional planning area of the WRAP. The emission sources include: emissions from outside the WRAP domain; emissions from Canada and Mexico; emissions from wildfires and windblown dust; and emissions from offshore shipping. Colorado anticipates that the long-term strategies when adopted by other states in their SIPs and approved by EPA will include emission reductions from a variety of sources that will reduce visibility impairment in Colorado"s Class I areas.

Colorado"s analysis of interstate impacts from specific nearby sources indicated the need for specific consultation with Nebraska, Wyoming, Utah, New Mexico and Arizona and California. In Nebraska the Gerald Gentleman Power Plant was analyzed for BART as part of the Nebraska RH process. Colorado commented to the State of Nebraska on this BART determination since emissions from this plant were indicated to impact Rocky Mountain National Park. Colorado similarly communicated with the State of Wyoming concerning BART determinations for its sources since impacts from Wyoming power plants were indicated to impact the Mt. Zirkel Wilderness Area. Colorado participated in the Four Corners Task force with Utah, New Mexico and Arizona and Tribal representatives to identify sources in the region adversely affecting air quality in the region. One element of that process was to consider sources impacting Mesa Verde or other Colorado Class I areas specifically for regional haze purposes. Through this process these States were made aware of Colorado"s concerns about emissions from the Four Corners Power Plant, as it significantly impacts Mesa Verde. EPA Region IX was notified of Colorado"s concerns with this facility since they are responsible for issuing and overseeing permits on this facility. Finally, California was contacted to discuss NOx emissions impacting Colorado Class I areas. California identified measures being taken in the State to reduce NOx emissions from mobile and other sources. Additional details concerning the Four Corners Task Force can be found in Section 9.5.5.3 of this Regional Haze SIP.

During the 2010 public hearing process, Colorado provided notification to the WRAP-member states and to other nearby states that a Regional Haze SIP revision had been prepared and invited review and comment on the plan and supporting documents.

By participating in the WRAP and the Four Corner"s Task Force, and through specific comments and communications with the participating states, Colorado has satisfied the state consultation requirement.

2.4 General Consultation

As part of the regional haze SIP development process Colorado will continue to coordinate and consult with parties as summarized in the long-term strategy described in Chapter 9.

Chapter 3 Monitoring Strategy

Federal regulations in 40 CFR 51.305 and 51.308(d)(4) require states to have a monitoring strategy in the SIP sufficient to characterize reasonable progress at each of the Class I areas, specifically Phase 1: reasonably attributable visibility impairment (RAVI) and Phase 2: regional haze visibility impairment in federal Class I areas within the state. Because Colorado adopted a visibility SIP to address the Phase 1 requirements (51.305), a monitoring strategy is currently in place through an approved SIP. The State of Colorado utilizes data from the IMPROVE monitoring system which is designed to provide a representative measure of visibility in each of Colorado's Class I areas.

3.1 RAVI Monitoring Strategy in Current Colorado LTS

States are required by EPA to have a monitoring strategy for evaluating visibility in any Class I area by visual observation or other appropriate monitoring techniques. The monitoring strategy in the RAVI LTS is based on meeting the following four goals:

1. To provide information for new source visibility impact analysis.
2. To determine existing conditions in Class I areas and the source(s) of any certified impairment.
3. To determine actual affects from the operation of new sources or modifications to major sources on nearby Class I areas.
4. To establish visibility trends in Class I areas to evaluate progress towards meeting the national visibility goal.

Potential new major source operators must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permit holder will be notified of the visibility levels against which impacts are to be assessed. If visibility data are not adequate, pre-construction monitoring of visibility may be required.

If the Federal Land Managers (FLMs) or the State of Colorado certifies existing impairment in a Class I area, the Division will determine if emissions from a local source(s) operator(s) can be reasonably attributed to cause or contribute to the documented visibility impairment. In making this determination the Division will consider all available data including the following:

1. Data supplied by the FLM;
2. The number and type of sources likely to impact visibility in the Class I area;
3. The existing emissions and control measures on the source(s);
4. The prevailing meteorology near the Class I area; and
5. Any modeling that may have been done for other air quality programs.

If available information is insufficient to make a decision regarding "reasonable attribution" of visibility impairment from an existing source(s) the State will initiate cooperative studies to help make such a determination. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others.

The monitoring strategy also included a commitment from the State to sponsor or share in the operation of visibility monitoring stations with FLMs as the need arises and resources allow.

The State commits to periodically compile information about visibility monitoring conducted by various entities throughout the State and assembling and evaluating visibility data.

Colorado law (C.R.S. 25-7-212(3)(a)) requires the federal land management agencies of Class I areas in Colorado (i.e., U.S.D.I. National Park Service and U.S.D.A. Forest Service) to "develop a plan for evaluating visibility in that area by visual observation or other appropriate monitoring technique approved by the federal environmental protection agency and shall submit such plan for approval by the division for incorporation by the commission as part of the state implementation plan." The agencies indicated they developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA‟s Regional Haze Rule (40 CFR 51.308(d)(4)) indicates, "The State must submit with the Implementation Plan a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment representative of all mandatory Class I Federal areas within the State….Compliance with this requirement may be met through participating in the Interagency Monitoring of Protected Visual Environments [IMPROVE] network." The federal agencies‟ monitoring plan relies on this network and ensures each Class I area in Colorado will have a monitor representative of visibility in the Class I area. In the LTS revision, submitted to EPA in 2008, the Division provided letters from the federal land managers and approval letters from the Division indicating this requirement was being met.

3.2 Regional Haze Visibility Impairment Monitoring Strategy

Under 40 CFR 51.308(d), a State must develop a monitoring strategy in the RH SIP to measure, characterize, and report regional haze visibility impairment representative of all federal Class I areas within the State. This monitoring strategy must be coordinated with the monitoring strategy described in Section 3.1 above, and will be met by participating in the IMPROVE network.

Colorado‟s monitoring strategy is to participate in the IMPROVE monitoring network. To insure coordination with the RAVI monitoring strategy, it includes the same four goals as in the RAVI LTS plus an additional goal:

> To provide regional haze monitoring representing all visibility-protected federal Class I areas

3.3 Associated Monitoring Strategy Requirements

Other associated monitoring strategy requirements in 40 CFR 51.308(d)(4) and Colorado"s associated SIP commitment are enumerated below:

1. Establishment of any additional monitoring sites or equipment to evaluate achievement of reasonable progress goals [40 CFR 51.308(d)(4)(i)].
   a. Colorado will work collaboratively with IMPROVE, EPA, the Federal Land Managers and other potential sponsors to ensure that representative monitoring continues for all of its Class I areas. If necessary, additional monitoring sites or equipment will be established to evaluate the achievement of reasonable progress goals.
   b. If funding for a site(s) is eliminated by EPA, the Division will consult with FLMs and IMPROVE to determine the best remaining site to use to represent the orphaned Class I areas.
2. Procedures describing how monitoring data and other information are used in determining the State"s contribution of emissions to visibility impairment in any federal Class I area [40 CFR 51.308(d)(4)(ii)].
   a. Colorado has participated extensively in the WRAP. One of the Regional Modeling Center (RMC) tools is the PSAT (PM Source Apportionment Technology) that relates emission sources to relative impacts at Class I areas. Details about PSAT are contained in the Technical Support Documents for each Class I area. Colorado will utilize the PSAT method and other models as needed and recommended by EPA modeling guidance for visibility evaluations, or other tools, to assist in determining the State"s emission contribution to visibility impairment in any federal Class I area. As part of this process the State commits to consult with the EPA and FLMs or other entities as deemed appropriate when using monitoring and other data to determine the State"s contribution of emissions to impairment in any Class I area.
   b. Colorado will continue to review monitoring data from the IMPROVE sites and examine the chemical composition of individual specie concentrations and trends, to help understand the relative contribution of emissions from upwind states on Colorado Class I areas and any contributions from Colorado to downwind Class I areas in other states. This will occur no less than every five years in association with periodic SIP, LTS and monitoring strategy progress reports and reviews.
3. Provisions for annually reporting visibility monitoring data to EPA [40 CFR 51.308(d)(4)(iv)].
   a. IMPROVE data are centrally compiled and made available to EPA, states and the public via various electronic formats and websites including IMPROVE (http://vista.cira.colostate.edu/improve/) and VIEWS (http://vista.cira.colostate.edu/views/)Through participation in the IMPROVE network, Colorado will partially satisfies the requirement to annually report to EPA visibility data for each of Colorado"s Class I areas.

b. An annual compilation of the Colorado data will be prepared and reported to the EPA electronically.

4. A statewide emissions inventory of pollutants reasonably expected to cause or contribute to visibility impairment for a baseline year, most recent year data is available, and future projected year [40 CFR 51.308(d)(4)(v)].
   a. Section 5.4 of this Plan includes a summary of Colorado statewide emissions by pollutant and source category. The inventory includes air pollution sources that can reasonably be expected to cause or contribute to visibility impairment to federal Class I areas.
      i. The WRAP-developed Plan02d (March 2008) inventory is both the baseline and most recent year of data available for a statewide inventory. It is an inventory intended to represent typical annual emissions during the baseline period, 2000-2004. From the baseline/current inventory, projections were made to 2018. The WRAP"s 2018 Base Case or PRP18b inventory was utilized for final model projections. This represented the most recent BART determinations reported by the States and EPA offices, projection of future fossil-fuel electric generation plants, revised control strategy rulemaking and updated permit limits for point and area sources in the WRAP region as of Spring 2009 (http://www.wrapedms.org/InventoryDesc.aspx). The emission inventory information was collaboratively developed between Division staff and the WRAP. A summarized western state and boundary condition inventory is available at: http://vista.cira.colostate.edu/TSS/Results/emis_smry_p02c_b18b_a5.xls
5. Commitment to update the emissions inventory [40 CFR 51.308(d)(4)(v)].
   a. Colorado will update its portion of the regional inventory, on the tri-annual cycle as dictated by the Air Emissions Reporting Rule (AERR) (see section 3.5) in order to track emission change commitments and trends as well as for input to regional modeling exercises.
6. Any additional reporting, recordkeeping, and measures necessary to evaluate and report on visibility [40 CFR 51.308(d)(4)(vi)].
   a. Colorado will provide any additional reporting, recordkeeping and measures necessary to evaluate and report on visibility but is unaware of the need for any specific commitment at this time beyond those made in this section and in the LTS section.

3.4 Overview of the IMPROVE Monitoring Network

In the mid-1980"s, the IMPROVE program was established to measure visibility impairment in mandatory Class I Federal areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials, Western States Air Resources

Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management.

The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in mandatory Class I federal areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and support the requirements of the federal visibility rules by providing regional haze monitoring representing all visibility-protected federal Class I areas where practical.

The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, consultants, public interest groups, and air quality regulators to better understand and protect the visual air quality resource in Class I areas. Most importantly, the IMPROVE Program scientifically documents for American citizens, the visual air quality of their wilderness areas and national parks.

In Colorado, there are six IMPROVE monitors that are listed under the site name in Figure 3-1. As shown, some monitors serve multiple Class I areas. For example, the monitor with site name Mount Zirkel is located just south of the Mount Zirkel Wilderness Area (on Buffalo Pass) but this monitor is also designated to represent the Rawah Wilderness Area.

Figure 3-1 Colorado Class I Areas and IMPROVE Monitor Locations

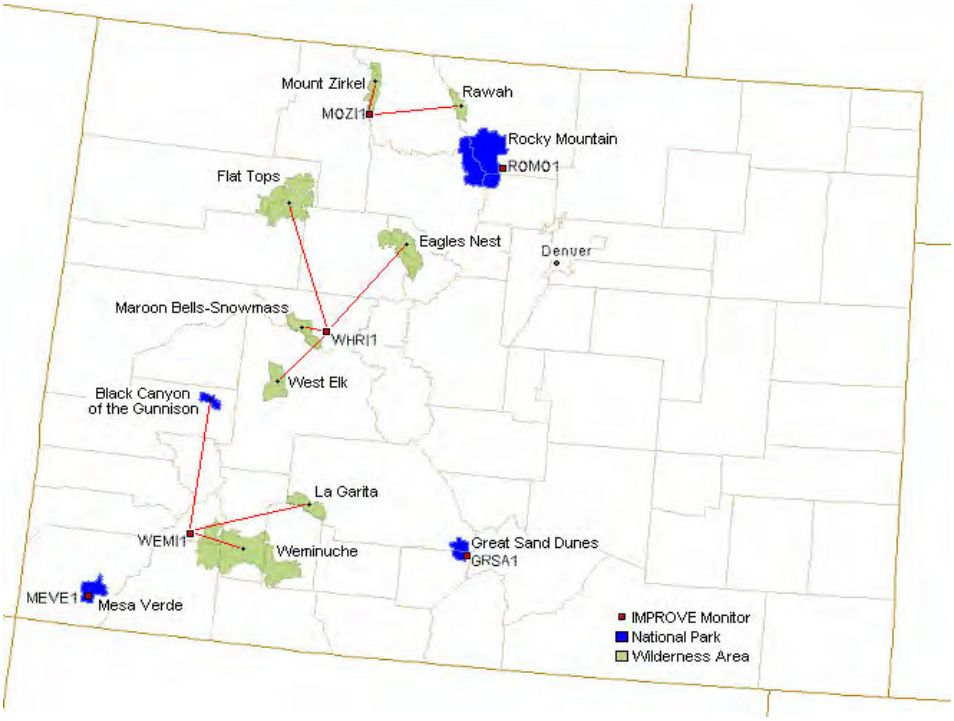


Figure 3-2 includes summary information for each IMPROVE monitor. The National Park Service (NPS) and the U.S. Forest Service (USFS) each operate and maintain three IMPROVE monitors in the State.

Figure 3-2 Colorado IMPROVE Monitoring Site Information

Mandatory Class I Federal Area	Operating Agency	IMPROVE Monitor	Elevation [ft]	Start Date
Great Sand Dunes National Park	NPS	GRSA1	8,215	5/4/1988
Mesa Verde National Park	NPS	MEVE1	7,142	3/5/1988
Mount Zirkel Wilderness	USFS	MOZI1	10,640	7/30/1994
Rawah Wilderness				
Rocky Mountain National Park	NPS	ROMO1	9,039	9/19/1990
Weminuche Wilderness	USFS	WEMI1	9,072	3/2/1988
Black Canyon of Gunnison NP				
La Garita Wilderness				
Eagles Nest Wilderness	USFS	WHRI1	11,214	7/17/2000
Flat Tops Wilderness				
Maroon Bells-Snowmass Wilderness				
West Elk Wilderness				

3.5 Commitment for Future Monitoring

The State commits to continue utilizing the IMPROVE monitoring data and emission data to track reasonable progress. The State commits to providing summary visibility data in electronic format to the EPA on an annual basis from the IMPROVE monitoring, or other relevant sites. Also, the State commits to continue developing updated emission inventories on a tri-annual basis as required under the Air Emissions Reporting Rule sufficient to allow for the tracking of emission increases or decreases attributable to adopted strategies or other factors such as growth, economic downturn, or voluntary or permit related issues. These monitoring and emissions data will be available for electronic processing in future modeling or other emission tracking processes. Information collected from the monitoring system and emission inventory work will be made available to the public.

Colorado will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program[2] to collect and report aerosol monitoring data for reasonable progress tracking as specified in the Regional Haze Rule (RHR). Because the RHR is a long-term tracking program with an implementation period nominally set for 60 years, the state expects the configuration of the monitors, sampling site locations, laboratory analysis methods and data quality assurance, and network operation protocols will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 RHR baseline period. Technical analyses and reasonable progress goals in RHR plans are based on data from these sites. The state must be notified and agree to any changes in the IMPROVE program affecting the RHR tracking sites, before changes are made. Further, the state notes resources to operate a complete and representative monitoring network of these long-term reasonable progress tracking sites is currently the responsibility of the Federal government. Colorado is satisfying the monitoring requirements by participating in the IMPROVE network. Colorado will continue to work with EPA in refining monitoring

[2] http://vista.cira.colostate.edu/improve/

strategies as new technologies become available in the future. If resource allocations change in supporting the monitoring network the state will work with the EPA and FLMs to address future monitoring requirements.

Colorado depends on IMPROVE program-operated monitors at six sites as identified in Figures 3.1 and 3.2 for tracking RHR reasonable progress. Colorado will depend on the routine timely reporting of monitoring data by the IMPROVE program for the reasonable progress tracking sites. Colorado commits to provide a yearly electronic report to the EPA of representative visibility data from the Colorado sites based on data availability from this network.

As required under 40 CFR 51.308(d)(4)(v) the State of Colorado has prepared a statewide inventory of emissions reasonably expected to cause or contribute to visibility impairment in Federal Class I Areas. Section 5.4 of this Plan summarizes the emissions by pollutant and source category.

The State of Colorado commits to updating statewide emissions on a tri-annual basis as required under the December 17, 2008 Air Emissions Reporting Rule (AERR). The updates will be used for state tracking of emission changes, trends, and input into any regional evaluation of whether reasonable progress goals are being achieved. Should no regional coordinating/planning agency exist in the future, Colorado commits to continue providing required emission updates as specified in the AERR and 40 CFR 51.308(d)(4)(v).

The State will use the Fire Emissions Tracking System (FETS)[3] to store and access fire emissions data. Should this system become unavailable Colorado will work with the FLMs and the EPA to establish a process to track and report fire emissions data if continued use of such information is deemed necessary. The State will also depend upon periodic collective emissions inventory efforts by other states meeting emission reporting requirements of the AERR to provide a regional inventory for future modeling and evaluations of regional haze impacts. Colorado recognizes that other inventories of a nature more sophisticated than available from the AERR may be required for future regional haze or other visibility modeling applications. In the past, such inventories were developed through joint efforts of states with the WRAP, and it is currently beyond available resources to provide an expanded regional haze modeling quality inventory if one is needed for future evaluations. The State will continue to depend on and use the capabilities of the WRAP-sponsored Regional Modeling Center (RMC)[4] or other similar joint modeling efforts to simulate the air quality impacts of emissions for haze planning purposes. The State notes the resources to ensure data preparation, storage, and analysis by the state and regional coordinating agencies such as the WRAP will require adequate ongoing resources. Colorado commits to work with other states, tribes, the FLMs and the EPA to help ensure future multi-state modeling, monitoring or inventory processes can be met but makes no commitment in this SIP to fund such processes. Colorado will track data related to RHR haze plan implementation for sources for which the state has regulatory authority.

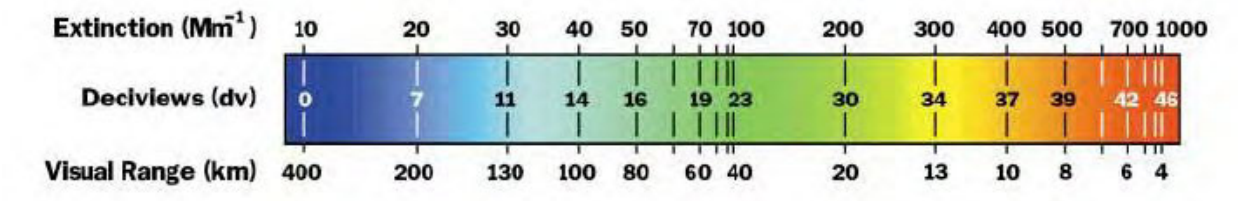
[3] http://www.wrapfets.org/
[4] http://pah.cert.ucr.edu/aqm/308/

Chapter 4 Baseline and Natural Visibility Conditions in Colorado, and Uniform Progress for Each Class I Area

4.1 The Deciview

Each IMPROVE monitor collects particulate concentration data which are converted into reconstructed light extinction through a complex calculation using the IMPROVE equation (see Technical Support Documents for any Class I area). Reconstructed light extinction (denoted as b_{ext}) is expressed in units of inverse megameters (1/Mm or Mm^{-1}). The Regional Haze Rule requires the tracking of visibility conditions in terms of the Haze Index (HI) metric expressed in ***the deciview (dv)*** unit [(40 CFR 51.308(d)(2)]. Generally, a one deciview change in the haze index is likely humanly perceptible under ideal conditions regardless of background visibility conditions.

The relationship between extinction (Mm^{-1}), haze index (dv) and visual range (km) are indicated by the following scale:



4.2 Baseline and Current Visibility Conditions

EPA requires the calculation of baseline conditions [(40 CFR 51.308(d)(2)(i) and (ii)]. The baseline condition for each Colorado Class I area is defined as the five year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in deciviews) for the most-impaired (20% worst) days and the least-impaired (20% best) days. For this first regional haze SIP submittal, the baseline conditions are the reference point against which visibility improvement is tracked. For subsequent RH SIP updates (in the year 2018 and every 10 years thereafter), baseline conditions are used to calculate progress from the beginning of the regional haze program.

Current conditions for the best and worst days are calculated from a multiyear average, based on the most recent 5-years of monitored data available [40 CFR 51.308(f)(1)]. This value will be revised at the time of each periodic SIP revision, and will be used to illustrate: (1) The amount of progress made since the last SIP revision, and (2) the amount of progress made from the baseline period of the program.

Colorado has established baseline visibility for the cleanest and worst visibility days for each Class I area based on, on-site data from the IMPROVE monitoring sites. A five-year average (2000 to 2004) was calculated for each value (both best and worst). The calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA"s *Guidance for Tracking Progress Under the Regional Haze Rule* (EPA-454/B-03-004, September 2003). The IMPROVE II algorithm as described in the TSDs has been utilized for the calculation of Uniform Rate of Progress glide slopes for all Class I areas. Figure 4-4 contains the baseline conditions for each IMPROVE monitor site in Colorado.

4.3 Monitoring Data

Visibility-impairing pollutants both reflect and absorb light in the atmosphere, thereby affecting the clarity of objects viewed at a distance by the human eye. Each haze pollutant has a different light extinction capability. In addition, relative humidity changes the effective light extinction of both nitrates and sulfates. Since haze pollutants can be present in varying amounts at different locations throughout the year, aerosol measurements of each visibility-impairing pollutant are made every three days at the IMPROVE monitors located in or near each Class I area.

In addition to extinction, the Regional Haze Rule requires another metric for analyzing visibility impairment, known as the “Haze Index”, which is based on the smallest unit of uniform visibility change that can be perceived by the human eye. The unit of measure is the deciview (denoted dv).

More detailed information on the methodology for reconstructing light extinction along with converting between the haze index and reconstructed light extinction can be found in the Technical Support Documents for any of Colorado"s twelve Class I areas.

The haze pollutants reported by the IMPROVE monitoring program are sulfates, nitrates, organic carbon, elemental carbon, fine soil and coarse mass. Summary data in Figures 4-1 and 4-2 are provided below for the worst and best days from the 6 IMPROVE monitors for the 6 haze pollutants.

Figure 4-1 Reconstructed Aerosol Components for 20% Worst Days (2000-2004)

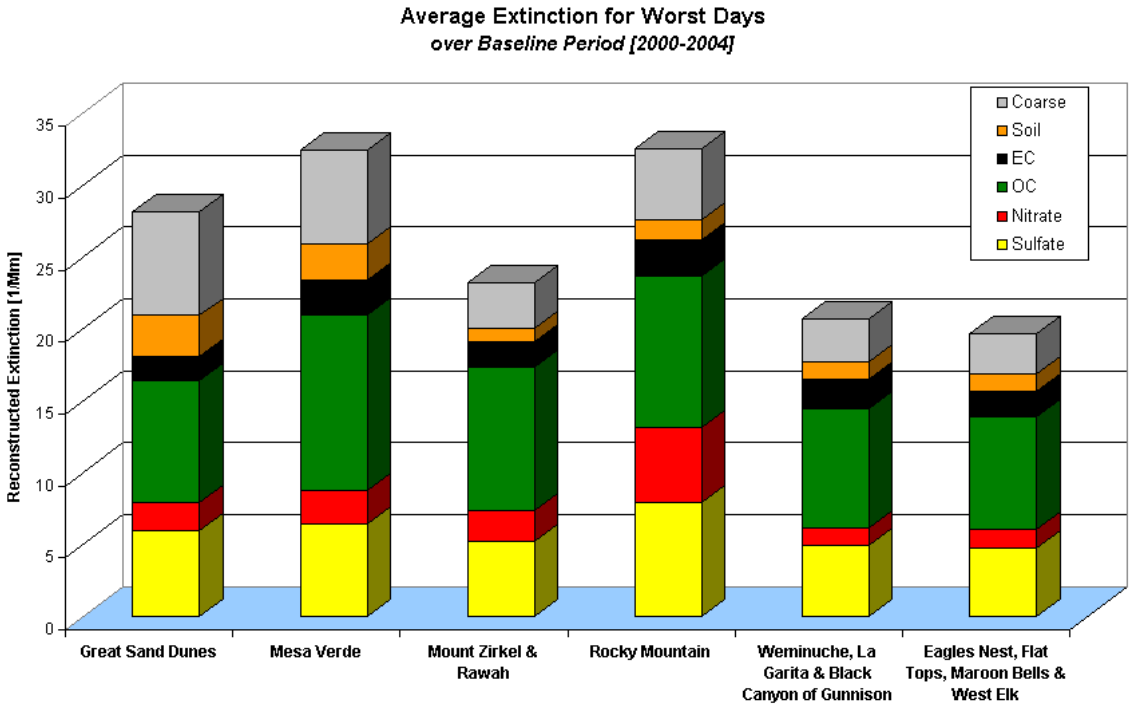
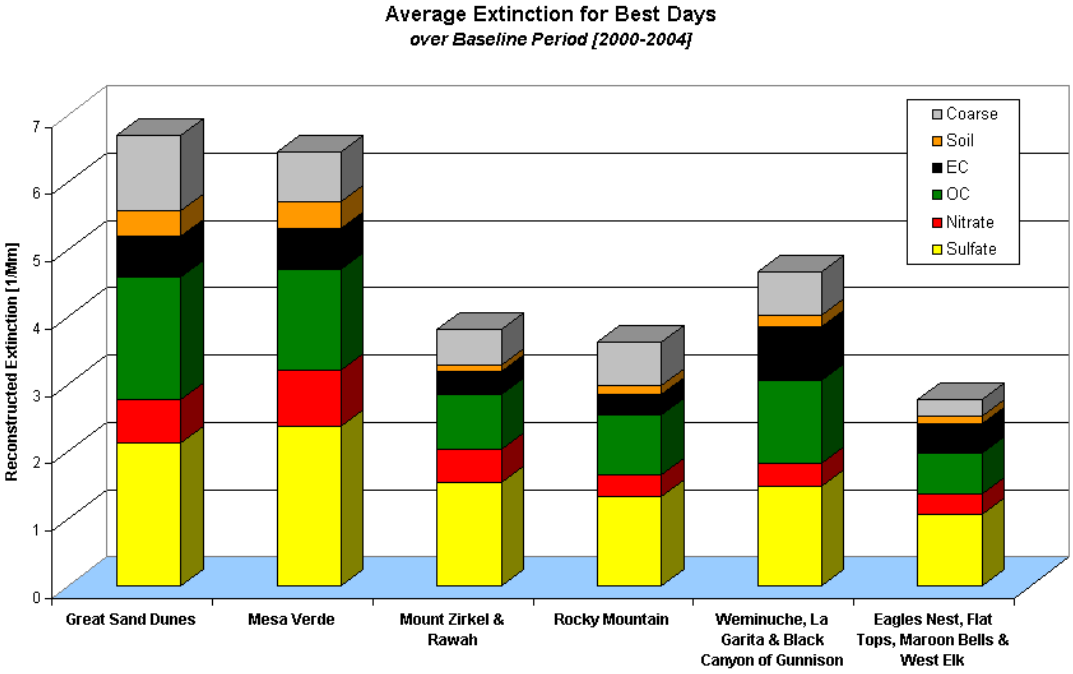


Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)



More detailed information on reconstructed extinction for each Class I area can be found in the Technical Support Document.

4.4 Natural Visibility Conditions

The natural condition for each Class I area represents the visibility goal expressed in deciviews for the most-impaired (20% worst) days and the least-impaired (20% best) days that would exist if there were only naturally occurring impairment. Natural visibility conditions must be calculated by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques. [(40 CFR 51.308(d)(iii)].

Figure 4-3, lists the 2064 natural conditions goal in deciviews for each Colorado Class I area. The natural conditions estimates were calculated consistent with EPA"s *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). The natural conditions goal can be adjusted as new visibility information becomes available. The Natural Haze Level II Committee methodology was utilized as described in the TSD.

Figure 4-3: 2064 Natural Conditions Goal for Worst Days

Mandatory Class I Federal Areas in Colorado	2064 Natural Conditions for 20% Worst Days [Deciview]
Great Sand Dunes National Park & Preserve	6.66
Mesa Verde National Park	6.81
Mount Zirkel & Rawah Wilderness Areas	6.08
Rocky Mountain National Park	7.15
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	6.21
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	6.06

4.5 Uniform Progress

For the worst days, uniform progress for each Colorado Class I area is the calculation of a uniform rate of progress per year to achieve natural conditions in 60 years [(40 CFR 51.308(d)(1)(i)(B)]. In this initial SIP submittal, the first benchmark is the 2018 deciview level based on the uniform rate of progress applied to the first fourteen years of the program. This is also shown in Figure 4-4 in the column "2018 Uniform Progress Goal (Deciview)".

For the 20% worst days, the uniform rate of progress (URP) in deciviews per year (i.e. slope of the glide path) is determined by the following equation:

URP = [Baseline Condition - Natural Condition] / 60 years

By multiplying the URP by the number of years in the 1st planning period one can calculate the uniform progress needed by 2018 to be on the path to achieving natural visibility conditions by 2064:

2018 UPG = [URP] x [14 years]

The 14 years comprising the 1st planning period includes the 4 years between the end of the baseline period and the SIP submittal date plus the standard 10-year planning period for subsequent SIP revisions.

More detailed information on the worst days along with the calculations and glide slope associated with each CIA can be found in Section 3 of the Technical Support Documents for any of Colorado"s twelve Class I areas. This calculation is consistent with EPA"s *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Rule* (June 1, 2007).

For the best days at each Class I area, the State must ensure no degradation in visibility for the least-impaired (20% best) days over the same period. More detailed information on the best days, along with the determination of the best day"s baseline for a particular CIA, can be found in Section 3 of the Technical Support Document.

Figure 4-4 provides the 2018 uniform rate of progress chart for the worst days and the baseline that must not be exceeded over the years in order to maintain the best days. As with natural conditions, uniform rate of progress can be adjusted as new visibility information becomes available.

Figure 4-4: Uniform Rate of Progress for Each Colorado Class I Area

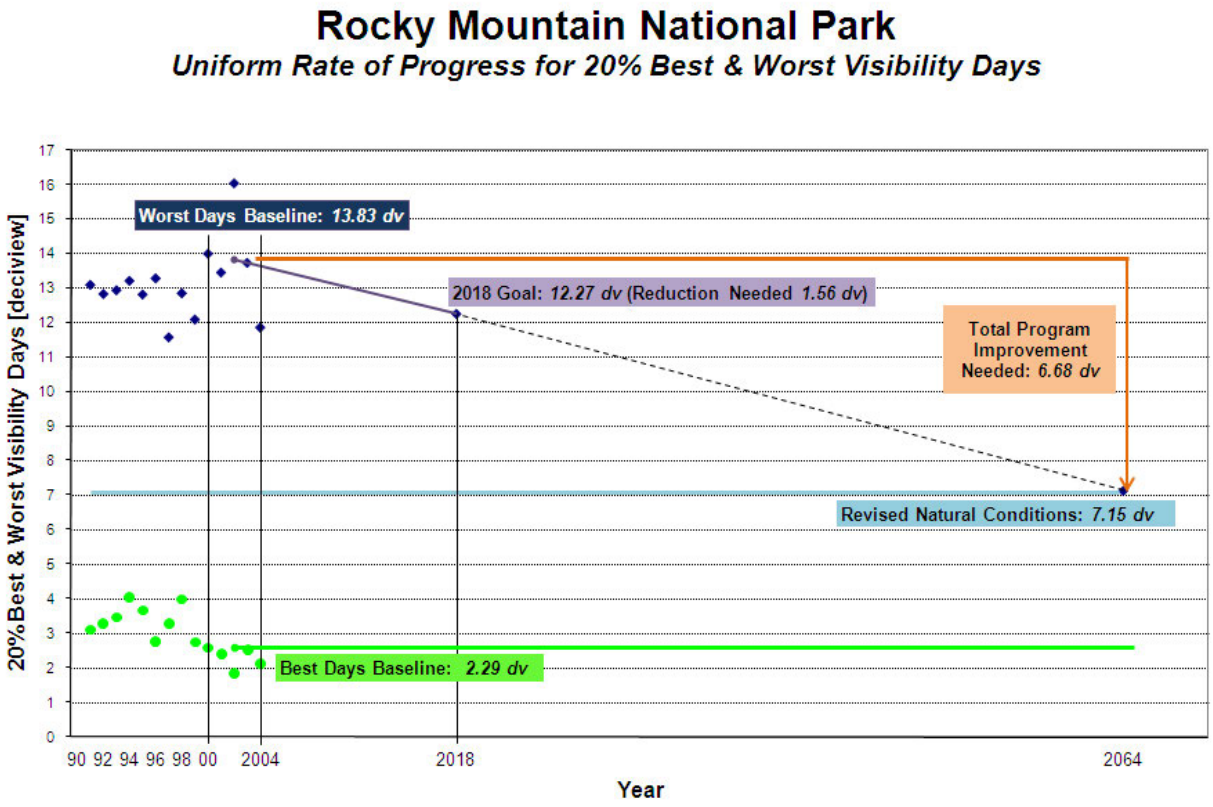
Baseline Summary of Best & Worst Days in Haze Index Metric

Baseline Period (2000-2004)

	20% Worst Days					20% Best Days
Mandatory Class I Federal Area	Baseline Condition [Deciview]	2018 Uniform Progress Goal [Deciview]	2018 Goal Delta [Deciview]	2064 Natural Conditions [deciview]	2064 Delta (Baseline - 2064 NC) [deciview]	Best Days Baseline Condition [Deciview]
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	6.66	6.12	4.50
Mesa Verde National Park	13.03	11.58	1.45	6.81	6.22	4.32
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	6.08	4.44	1.61
Rocky Mountain National Park	13.83	12.27	1.56	7.15	6.68	2.29
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	6.21	4.12	3.11
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	6.06	3.55	0.70

Figure 4-5 provides a visual example of 2018 uniform progress glide slope for the worst days and the best days baseline.

Figure 4-5: Example of Uniform Progress for 20% Best & Worst Days at Rocky Mountain National Park



Chapter 5 Sources of Impairment in Colorado

5.1 Natural Sources of Visibility Impairment

Natural sources of visibility impairment include anything not directly attributed to human-caused emissions of visibility-impairing pollutants. Natural events (e.g. windblown dust, wildfire, volcanic activity, biogenic emissions) also introduce pollutants contributing to haze in the atmosphere. Natural visibility conditions are not constant; they vary with changing natural processes throughout the year. Specific natural events can lead to high short-term concentrations of visibility-impairing particulate matter and its precursors. Natural visibility conditions, for the purpose of Colorado"s regional haze program, are represented by a long-term average of conditions expected to occur in the absence of emissions normally attributed to human activities. Natural visibility conditions reflect contemporary vegetated landscape, land-use patterns, and meteorological/climatic conditions. The 2064 goal is the natural visibility conditions for the 20% worst natural conditions days.

Natural sources contribute to visibility impairment but natural emissions cannot be realistically controlled or prevented by Colorado and therefore are beyond the scope of this plan. Current methods of analysis of IMPROVE data do not provide a distinction between natural and anthropogenic emissions. Instead, for the purposes of this SIP, they are estimated as described in Section 4.4.

5.2 Anthropogenic Sources of Visibility Impairment

Anthropogenic or human-caused sources of visibility impairment include anything directly attributable to human-caused activities producing emissions of visibility-impairing pollutants. Some examples include transportation, agriculture activities, mining operations, and fuel combustion. Anthropogenic visibility conditions are not constant and vary with changing human activities throughout the year. Generally anthropogenic emissions include not only those anthropogenic emissions generated or originating within the boundaries of the United States but also international emissions transported into a state. Some examples include emissions from Mexico, Canada, and maritime shipping emissions in the Pacific Ocean.

Although anthropogenic sources contribute to visibility impairment, international emissions cannot be regulated, controlled or prevented by the states and therefore are beyond the scope of this planning document. Any reductions in international emissions would likely fall under the purview of the U.S. EPA administrator.

5.3 Overview of Emission Inventory System -TSS

The Western Regional Air Partnership (WRAP) developed the Technical Support System (TSS) as an Internet access portal to all the data and analysis associated with the development of the technical foundations of Regional Haze plans across the Western US. The TSS provides state, county, and grid cell level emissions information for typical criteria pollutants such as SO2 & NOx and other secondary particulate forming pollutants such as VOC and NH3. Eleven different emission inventories were developed comprising the following source categories: point, area, on-road mobile, off-road mobile, oil and gas, anthropogenic fire, natural fire, biogenic, road dust, fugitive dust and windblown dust. Summaries of the emissions data for sources in Colorado are contained in subsequent Figures 5-1 through 5-8 in this section. In addition the Emissions Inventory TSD in this SIP contains a more detailed accounting of sources in Colorado used in the modeling exercise.

In the WRAP process, member states and the EPA agreed the tremendous amount of data collected, analyzed and maintained by the WRAP and the Regional Modeling Center would be impracticable and nearly infeasible to include in individual TSDs for individual States. For the purposes of administrative efficiency, WRAP data and analysis upon which the member states built their Regional Haze SIPs are available through the WRAP on the TSS Web site. For a more complete description of the emission inventory and process and for access information related to the web site containing comprehensive detail about the inventory please refer to the Emissions Inventory TSD in this SIP.

5.4 Emissions in Colorado

Federal visibility regulations (40 CFR 51.308(d)(4)(v)) require a statewide emission inventory of pollutants reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The pollutants inventoried by the WRAP that Colorado used for this SIP include sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (Soil-PM2.5), coarse particulate (PM-2.5 to PM-10), and ammonia (NH3). An inventory was developed for the baseline year 2002, and projections of future emissions have been made for 2018. Colorado will provide updates to the EPA on this inventory on a three year basis as required by the AERR. Not all of the categories used for modeling purposes are contained in the AERR. A summary of the inventory results follows; the complete emission inventory is included in Section 5 of the Technical Support Document.

Emission inventories form one leg of the analysis stool to evaluate sources" impacts on visibility. Emission inventories are created for all of critical chemicals or species known to directly or indirectly impact visual air quality. These inventories become inputs to air quality models predicting concentrations of pollutants over a given space and time. For this SIP, the WRAP developed emission inventories for each state with input from participating stakeholders. A complete description of the development and content of the emission inventories can be found on the WRAP Technical Support System web

site: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx and a summary description of the inventory is found in the Emission Inventory TSD.

Dispersion modeling predicts daily atmospheric concentrations of pollutants for the baseline year and these modeled results are compared to monitored data taken from the IMPROVE network. A second inventory is created to predict emissions in 2018 based on expected controls, growth, or other factors. Additional inventories are created for future years to simulate the impact of different control strategies. The process for inventorying sources is similar for all species of interest. The number and types of sources is identified by various methods. For example, major stationary sources report actual annual emission rates to the EPA national emissions database. Colorado collects annual emission data from both major and minor sources and this information is used as input into the emissions inventory. In other cases, such as mobile sources, an EPA mobile source emissions model is used to develop emission projections. Colorado vehicle registration, vehicle mile traveled information and other vehicle data are used to tailor the mobile source data to best represent statewide and area specific emissions. Population, employment and household data are used in other parts of the emissions modeling to characterize emissions from area sources such as home heating. Thus, for each source type, emissions are calculated based on an emission rate and the amount of time the source is operating. Emission rates can be based on actual measurements from the source, or EPA emission factors based on data from tests of similar types of emission sources. In essence all sources go through the same process. The number of sources is identified, emission rates are determined by measurements of those types of sources and the time of operation is determined. By multiplying the emission rate times the hours of operation in a day, a daily emission rate can be calculated.

It is noted that certain source categories are more difficult to make current and future projections for. This is simply because market dynamics, growth factors, improvements in emission factors, types and number of sources, improvements in controls and changes in regulations make the future less predictable. Oil and gas sources in Colorado can be substantial for selected pollutants and significant efforts went into this SIP to improve emissions estimates for Colorado and other western states to help make the modeling as reflective as possible of known and future emissions. Future SIP updates will take into account any new information related to this, and other, source categories.

The following presents the Colorado emissions from the TSS, as provided to the WRAP early 2009. The “Plan 2002(d)” and “PRP 2018(b)” phrases on each of the emission inventory tables signify the version of inventories by year. A detailed explanation of each plan can be found in the Emission Inventory TSD. These inventories do not reflect the additional emission reductions that will result from the 2010 revised Best Available Retrofit Technology and reasonable progress determinations. An accounting of these emission reductions are presented in Chapter 9 of this plan.

Figure 5-1 Colorado SO2 Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide SO2 Emissions		
	Plan 2002(d)	PRP 2018(b)	Net
	[tons/year]	[tons/year]	Change
Point	97,984	44,062	-55%
Area	6,533	7,644	17%
On-Road Mobile	4,389	677	-85%
Off-Road Mobile	3,015	754	-75%
WRAP Area O&G	118	11	-91%
Road Dust	4	6	34%
Fugitive Dust	6	5	-13%
Anthro Fire	108	91	-15%
Natural Fire	3,335	3,335	0%
Biogenic	-	-	-
Total:	**115,492**	**56,585**	**-51%**

Sulfur dioxide emissions produce sulfate particles in the atmosphere. Ammonium sulfate particles have a significantly greater impact on visibility than pollutants like dust from unpaved roads due to the physical characteristics causing greater light scattering from the particles. Sulfur dioxide emissions come primarily from coal combustion at electrical generation facilities but smaller amounts come from natural gas combustion, mobile sources and even wood combustion. Other than natural fire there are no biogenic SO2 emissions of significance in Colorado. Even allowing for those fire-related sulfur dioxide emissions to be counted as „natural" these represent only 3% of the statewide inventory. A 51% statewide reduction in SO2 emissions is expected by 2018 due to planned controls on existing point sources, even with a growth consideration for electrical generating capacity for the State. Similar reductions in the West are expected from other states as BART or other planned controls take effect by 2018. The only sulfur dioxide category expected to increase is area sources. Area sources of sulfur oxides are linked to population growth as the activity factor. As population increases in Colorado from the base case to 2018, this category is expected to increase. A typical area source for sulfur dioxide would be home heating.

Figure 5-2 Colorado NO_x Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide NOx Emissions		
	Plan 2002(d) *[tons/year]*	PRP 2018(b) *[tons/year]*	Net Change
Point	118,667	101,818	-14%
Area	11,729	16,360	39%
On-Road Mobile	141,883	45,249	-68%
Off-Road Mobile	62,448	37,916	-39%
WRAP Area O&G	23,518	33,517	43%
Road Dust	1	1	32%
Fugitive Dust	16	14	-13%
Anthro Fire	520	408	-21%
Natural Fire	9,377	9,377	0%
Biogenic	37,349	37,349	0%
Total:	**405,507**	**282,010**	**-30%**

Nitrogen oxides (NOx) are generated during any combustion process where nitrogen and oxygen from the atmosphere combine together under high temperature to form nitric oxide, and to a lesser degree nitrogen dioxide. Other odd oxides of nitrogen are also produced to a much smaller degree. Nitrogen oxides react in the atmosphere to form nitrate particles. Larger nitrate particles have a slightly greater impact on visibility than do sulfate particles of the same size and are much more effective at scattering light than mineral dust particles. Nitrogen oxide emissions in Colorado are expected to decline by 2018, primarily due to significant emission reductions from point, mobile and area sources. Off-road and on-road vehicles emissions will decline by more than 80,000 tons per year from the base case emissions total of 204,000 tons per year. Increases in area sources, as with sulfur dioxide, are related to population growth with an expected 4,000 tons per year increase by 2018. Again, home heating would be a typical area source of NOx with growth in emissions related to population increases. Oil and gas development by 2018 is also expected to increase statewide emissions by about 10,000 tons per year.

Figure 5-3 Colorado VOC Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	**Statewide VOC Emissions**		
	Plan 2002(d)	PRP 2018(b)	Net
	[tons/year]	*[tons/year]*	Change
Point	91,750	77,312	-16%
Area	99,191	136,032	37%
On-Road Mobile	100,860	41,489	-59%
Off-Road Mobile	38,401	24,684	-36%
WRAP Area O&G	27,259	43,639	60%
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	915	666	-27%
Natural Fire	20,404	20,404	0%
Biogenic	804,777	804,777	0%
Total:	**1,183,557**	**1,149,002**	**-3%**

Volatile organic compounds (VOCs) are expected to decline slightly by 2018. Among other sources, volatile organic compounds from automobiles, industrial and commercial facilities, solvent use, and refueling automobiles all contribute to VOC loading in the atmosphere. Substantial natural emissions of VOCs come from vegetation. VOCs can directly impact visibility as emissions condense in the atmosphere to form an aerosol. Of more significance is the role VOCs play in the photochemical production of ozone in the troposphere. Volatile organic compounds react with nitrogen oxides to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. The large increase in area sources is again related to population increases. Use of solvents such as in painting, dry cleaning, charcoal lighter, and windshield washer fluids, and many home use products, show up in the area source category and increases in this area are linked to population growth.

Figure 5-4 Colorado Primary Organic Aerosol (POA) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide POA Emissions		
	Plan 2002(d)	PRP 2018(b)	Net
	[tons/year]	*[tons/year]*	Change
Point	17	3	-83%
Area	8,432	8,738	4%
On-Road Mobile	1,280	1,288	1%
Off-Road Mobile	1,286	843	-34%
WRAP Area O&G	-	-	-
Road Dust	102	135	33%
Fugitive Dust	777	677	-13%
Anthro Fire	850	621	-27%
Natural Fire	30,581	30,581	0%
Biogenic	-	-	-
Total:	**43,325**	**42,886**	**-1%**

Primary Organic Aerosols (POAs) are organic carbon particles emitted directly from the combustion of organic material. A wide variety of sources contribute to this classification including cooking of meat to diesel emissions and combustion byproducts from wood and agricultural burning. Area sources and automobile emissions dominate this classification. Increases in areas sources are due to population increases. These increases are offset by expected improvements in automobile emissions and by 2018 emissions from this category are expected to decline by about 5%.

Figure 5-5 Colorado Elemental Carbon (EC) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide EC Emissions		
	Plan 2002(d)	PRP 2018(b)	Net
	[tons/year]	*[tons/year]*	Change
Point	-	-	-
Area	1,264	1,325	5%
On-Road Mobile	1,448	408	-72%
Off-Road Mobile	3,175	1,344	-58%
WRAP Area O&G	-	-	-
Road Dust	9	11	33%
Fugitive Dust	53	46	-13%
Anthro Fire	92	74	-20%
Natural Fire	6,337	6,337	0%
Biogenic	-	-	-
Total:	**12,377**	**9,545**	**-23%**

Elemental carbon is the carbon black, or soot, a byproduct of incomplete combustion. It is the partner to primary organic aerosols and represents the more complete combustion of fuel producing carbon particulate matter as the end product. A carbon particle has a sixteen times greater impact on visibility than a coarse particle of granite has. Emissions, and reductions, in this category are dominated by mobile sources and expected new federal emission standards for mobile sources, especially for diesel engines, along with fleet replacement are the reason for these reductions.

Figure 5-6 Colorado Soil (PM Fine) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide Soil (fine PM) Emissions		
	Plan 2002(d)	PRP 2018(b)	Net
	[tons/year]	*[tons/year]*	Change
Point	6	85	1404%
Area	4,170	4,311	3%
On-Road Mobile	-	-	-
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	1,082	1,435	33%
Fugitive Dust	13,401	11,679	-13%
Windblown Dust	15,105	15,105	0%
Anthro Fire	253	169	-33%
Natural Fire	1,948	1,948	0%
Biogenic	-	-	-
Total:	**35,964**	**34,732**	**-3%**

Fine soil emissions are largely related to agricultural and mining activities, windblown dust from construction areas and emissions from unpaved and paved roads. A particle of fine dust has a relative impact on visibility one tenth as great as a particle of elemental carbon. Monitoring at all sites in Colorado indicates soil is present as a small but measurable part of the visibility problem. On any given visibility event where poor visual air quality is present in a scene, the impact of dust can vary widely. Overall, on the 20% worst days, fine soil has about the same impact as nitrate particles. Agricultural activities, dust from unpaved roads and construction are prevalent in this source category and changes in emissions are tied to population and vehicle miles traveled. Since soil emissions are not directly from the tailpipe of the vehicle, the category of mobile sources does not show any emissions and all vehicle related emissions from paved and unpaved roads show up in the fugitive dust category.

Figure 5-7 Colorado Coarse Mass (PM Coarse) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide Coarse PM Emissions		
	Plan 2002(d)	PRP 2018(b)	Net
	[tons/year]	*[tons/year]*	Change
Point	21,096	26,828	27%
Area	1,363	1,388	2%
On-Road Mobile	794	917	15%
Off-Road Mobile	-	-	-
WRAP Area O&G	-	-	-
Road Dust	8,930	11,826	32%
Fugitive Dust	67,642	67,910	0%
Windblown Dust	135,945	135,945	0%
Anthro Fire	51	32	-37%
Natural Fire	5,973	5,973	0%
Biogenic	-	-	-
Total:	**241,794**	**250,818**	**4%**

Particulate matter, also identified as coarse mass particles emissions, are closely related to the same sources as fine soil emissions but other activities like rock crushing and processing, material transfer, open pit mining and unpaved road emissions can be prominent sources. Coarse mass particles travel shorter distances in the atmosphere than some other smaller particles but can remain in the atmosphere sufficiently long enough to play a role in regional haze. Coarse mass particulate matter has the smallest direct impact on regional haze on a particle-by-particle basis where one particle of coarse mass has a relative visibility weight of 0.6 compared to a carbon particle having a weight of 10. Nevertheless, they are commonly present at all monitoring sites and are a greater contributor to regional haze than the fine soil component. Substantial increases in coarse mass are seen in the fugitive dust category. This is due to the fact that construction and emissions from paved and unpaved roads are lined to population, vehicle miles traveled and employment data. Growth in these factors results in these categories increasing from 2002 to 2018. For this planning period, the state evaluated PM from stationary sources, but not from natural sources.

Figure 5-8 Colorado Ammonia (NH3) Emission Inventory – 2002 & 2018

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide Ammonia Emissions		
	Plan 2002(d)	PRP 2018(b)	Net
	[tons/year]	*[tons/year]*	Change
Point	453	571	26%
Area	60,771	60,791	0%
On-Road Mobile	4,317	5,894	37%
Off-Road Mobile	43	60	38%
WRAP Area O&G	-	-	-
Road Dust	-	-	-
Fugitive Dust	-	-	-
Anthro Fire	137	95	-31%
Natural Fire	1,965	1,965	0%
Biogenic	-	-	-
Total:	**67,686**	**69,375**	**2%**

Ammonia emissions come from a variety of sources including wastewater treatment facilities, livestock operations, and fertilizer application and to a small extent, mobile sources. Increases in ammonia emission from the base case year to 2018 are linked to population statistics and increased vehicular traffic. Ammonia is directly linked to the production of ammonium nitrate and ammonium sulfate particles in the atmosphere when sulfur dioxide and nitrogen oxides eventually convert over to these forms of particles. Expected growth in the mobile source emissions from 2002 to 2018 is due to the fact that no specific controls on mobile sources are implemented and increases in vehicle miles traveled links directly to increased ammonia emissions.

Chapter 6 Best Available Retrofit Technology

6.1 Introduction

One of the principal elements of Section 169A of the 1977 Clean Air Act Amendments addresses the installation of Best Available Retrofit Technology (BART) for certain existing sources of pollution. The provision, 169A (b)(2), demonstrates Congress" intent to focus attention directly on pollution from a specific group of existing sources. The U.S. Environmental Protection Agency"s (EPA) Regional Haze Rule requires certain emission sources that may reasonably be anticipated to cause or contribute to visibility impairment in downwind Class I areas to install BART. *See* 40 CFR §51.308(e); *see also* 64 Fed. Reg. 35714 *et seq.* (July 1, 1999). These requirements are intended to reduce emissions from certain large sources that, due to age, were exempted from other requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories including power plants, cement kilns and industrial boilers. To be considered BART-eligible, sources from these categories must have the potential to emit 250 tons or more of haze forming pollution and must have commenced operation in the 15-year period prior to August 7, 1977.

Because of the regional focus of this requirement in the Regional Haze Rule, BART applies to a larger number of sources than the Phase 1 reasonably attributable visibility impairment requirements. In addition to source-by-source command and control BART implementation, EPA has allowed for more flexible alternatives if they achieve greater progress toward the state"s visibility goals than the standard BART approach.

This document demonstrates how Colorado has satisfied the BART requirements in EPA"s Regional Haze Rule. Colorado"s review process is described and a list of BART-eligible sources is provided. A list of sources that are subject to BART is also provided, along with the requisite modeling analysis approach and justification.

6.2 Overview of Colorado's BART Regulation

Colorado"s Air Quality Control Commission approved a State-only BART regulation (Regulation 3 Part F) on March 16, 2006, that became effective in May 2006. A summary of the Colorado BART program and determinations is set out below, in Section 6.3. More detail is provided in Regulation Number 3 Part F, Appendix C to this document, the Technical Support Document (TSD), and at the Division"s BART website at: http://www.cdphe.state.co.us/ap/RegionalHazeBART.html.

Colorado"s BART Rule includes the following major provisions:

1. Visibility impairing pollutants are defined to include SO2, NOx and particulate matter.
2. Visibility impact levels are established for determining whether a given source causes or contributes to visibility impairment for purposes of the source being

subject-to-BART (or excluded). The causation threshold is 1.0 deciview and the contribution threshold is 0.5 deciview. Individual sources are exempt from BART if the 98th percentile daily change in visibility from the facility, as compared against natural background conditions, is less than 0.5 deciview at all Class I federal areas for each year modeled and for the entire multi-year modeling period.

3. BART controls are established based on a case-by-case analysis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These factors are established in the definition of Best Available Retrofit Technology.
4. Provision that the installation of regional haze BART controls exempts a source from additional BART controls for regional haze, but does not exempt a source from additional controls or emission reductions that may be necessary to make reasonable progress under the regional haze SIP.

6.3 Summary of Colorado's BART Determinations

Colorado"s Air Quality Control Commission elected to assume that all BART-eligible sources are subject to BART, but required the Division to perform modeling to determine whether BART-eligible sources will cause or contribute to visibility impairment at any Class I area. The threshold for causing or contributing to impairment was 0.5 or greater deciview impact. BART-eligible sources that did not cause or contribute 0.5 or greater deciview impact would not be subject to BART.

Once the complete list of eligible sources had been assembled, the list was reviewed to determine the current status of each source. A number of sources were eliminated for various reasons. One plant was being shut down. Two others were found not to be subject to BART because the size of the boilers was less than the 250 MMBtu/hour limit identified in the EPA BART Rule. Two sources were not subject to BART because they had been re-constructed after the BART period, and two were exempt because VOCs are not a visibility impairing pollutant under Colorado's BART Rule. The final list of sources was modeled by the Division to determine if they met the "cause or contribute" criteria. The results of this modeling are reflected in Table 6 - 1 below.

Table 6 - 1 Results of Subject-to-BART Modeling

Modeled BART–Eligible Source	Division Modeling (98th percentile delta-deciview value)	Division Approved Refined Modeling from Source Operator (98th percentile delta-deciview value)	Contribution Threshold (deciviews)	Impact Equal to or Greater Than Contribution Threshold?
CEMEX - Lyons Cement Kiln & Dryer	1.533		0.5	Yes
CENC (Trigen-Colorado) Units 4 & 5	1.255		0.5	Yes
Cherokee Station – Unit 4	1.460		0.5	Yes
Comanche Station – Units 1 and 2	0.701		0.5	Yes
Craig Station – Units 1 & 2	2.689		0.5	Yes
Hayden Station – Units 1 & 2	2.538		0.5	Yes
Lamar Light & Power – Unit 6	0.064		0.5	No
Martin Drake Power Plant – Units 5, 6 & 7	1.041		0.5	Yes
Pawnee Station – Unit 1	1.189		0.5	Yes
Ray D. Nixon Power Plant – Unit 1	0.570	0.481	0.5	No
Suncor Denver Refinery	0.239		0.5	No
Valmont Station – Unit 5	1.591		0.5	Yes

Notes:

1. The contribution threshold has an implied level of precision equal to the level of precision reported from the model.
2. Source operator modeling results are shown only if modeling has been approved by Division.
3. Roche is not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment.
4. Denver Steam is not included because it is exempt by rule (natural gas only <250 MMBtu).
5. Holcim Cement (Florence) and Rocky Mountain Steel Mills (Pueblo) are not included because of facility reconstruction.
6. Changes to the Ray D. Nixon Power Plant modeling included refinement of the meteorological fields and emission rates. The Division has issued a permit modification for this facility that includes a 30-day rolling emission limit for SO2.
7. Suncor Denver Refinery (including the former Valero Refinery) was not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment. Moreover, Suncor has installed controls to comply with MACT standards.

Of the BART-eligible sources listed above, those sources with a visibility contribution threshold equal to or greater than 0.5 deciview were determined to be subject-to-BART. Tables 6 - 2 and 6 - 3 include the BART determinations that will apply to each source.

Table 6 - 2 BART Determinations for Colorado Sources

Emission Unit	Assumed ** NOx Control Type	NOx Emission Limit	Assumed ** SO_2 Control Type	SO_2 Emission Limit	Assumed ** Particulate Control and Emission Limit
Cemex - Lyons Kiln	Selective Non-Catalytic Reduction System	255.3 lbs/hr (30-day rolling average) 901.0 tons/yr (12-month rolling average)	None	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	Fabric Filter Baghouse * 0.275 lb/ton of dry feed 20% opacity
Cemex - Lyons Dryer	None	13.9 tons/yr	None	36.7 tons/yr	Fabric Filter Baghouse* 22.8 tons/yr 10% opacity
CENC Unit 4	Low NOx Burners with Separated Over-Fire Air	0.37 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
CENC Unit 5	Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System	0.19 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
Comanche Unit 1	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu

Table 6 - 2 BART Determinations for Colorado Sources

Emission Unit	Assumed ** NOx Control Type	NOx Emission Limit	Assumed ** SO_2 Control Type	SO_2 Emission Limit	Assumed ** Particulate Control and Emission Limit
Comanche Unit 2	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 1	Selective Non-Catalytic Reduction System	0.28 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 2	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 1	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 2	Selective Catalytic Reduction System	0.07 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 5	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Dry Sorbent Injection	0.26 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 6	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 7	Ultra Low-NOx Burners (including Over-Fire Air)	0.29 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

Table 6 - 3 BART Determinations for PSCo's BART Alternative Sources [5, 6, 7]

Emission Unit	NOx Control Type	NOx Emission Limit	SO_2 Control Type	SO_2 Emission Limit	Particulate Control and Emission Limit
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation 12/31/2017	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (rolling 12 month average) 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (rolling 12 month average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

* Controls are already operating

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

For all BART and BART alternative determinations, approved in the Federal State Implementation Plan, the state affirms that the BART emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional

[5] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.
[6] 500 tpy NOx will be reserved from Cherokee station for netting or offsets.
[7] 300 tpy NOx will be reserved from Arapahoe station for netting or offsets for additional natural gas generation.

Haze analyses or Regional Haze controls will be required by the state during this timeframe.

6.4 Overview of Colorado's BART Determinations

Colorado has been evaluating BART issues for many years and has closely followed EPA"s proposals and final rules. The list of Colorado BART-eligible sources has been well known since the 1990"s, based on EPA"s expected applicability dates of between August 7, 1962 and August 7, 1977. Colorado has been involved in four BART-like proceedings involving known BART sources. Two of these determinations resulted from actions related to the Hayden and Craig power plants. These plants were identified in a certification of impairment made by the U.S. Forest Service regarding visibility impacts at Mt. Zirkel Wilderness Area, located northeast of Steamboat Springs. Colorado conducted two additional BART proceedings for all sources in 2007 and in 2008, which were submitted to EPA for approval. A number of these determinations were revised in 2010 based on adverse comments from EPA; Table 6-2 presents the 2010 BART determinations.

6.4.1 The State's Consideration of BART Factors

In identifying a level of control as BART, States are required by section 169A(g) of the Clean Air Act to "take into consideration" the following factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and
(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

42 U.S.C. § 7491(g)(2).

Colorado"s BART regulation requires that the five statutory factors be considered for all BART sources. *See,* Regulation No. 3, Part E, Section IV.B.1. In making its BART determination for each Colorado source, the state took into consideration the five statutory factors on a case-by case basis, and for significant NOx controls the Division also utilized the guidance criteria set forth in Section 6.4.3 consistent with the five factors. Summaries of the state"s facility-specific consideration of the five factors and resulting determinations for each BART source are provided in this Chapter 6. Documentation reflecting the state"s analyses and supporting the state"s BART determinations, including underlying data and detailed descriptions of the state"s analysis for each facility, are provided in Appendix C of this document.

6.4.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each BART unit. The cost information ranged from the installation and operation of new SO2 and NOx control equipment to upgrade analyses of existing SO2 controls. The cost for each unit is summarized below, and the state"s consideration of this factor for each source is presented in detail in Appendix C.

6.4.1.2 The energy and non-air quality environmental impacts of compliance. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each BART unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

6.4.1.3 Any existing pollution control technology in use at the source. The state has taken into consideration the existing PM, SO2 and NOx pollution control equipment in use at each Colorado source, as part of its BART determination process.

The Division has reviewed available particulate controls. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM" *see* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix C.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 6, in Appendix C and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix C.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate

When determining the emission rates for each source, the state referred to and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that BART relates to retrofitting sources (vs. new or reconstructed facilities), a review of other determinations was used to better substantiate the source specific information provided by the source.

6.4.1.4 The remaining useful life of the source. None of Colorado"s BART sources are expected to retire over the next twenty years. Therefore, this factor did not affect any of the state"s BART determinations.

6.4.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of BART. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of BART. Modeling information for each BART determination is presented below and in Appendix C.

6.4.2 SIP Requirements from EPA's Regional Haze Rule

The following section includes information addressing the SIP elements contained in EPA"s Regional Haze Rule. The section numbers refer to provisions in 40 CFR § 51.308(e), the BART provision of the Regional Haze Rule.

(i) A list of all BART-eligible sources within the State.

Table 6 - 3 below lists the initial group of Colorado sources subject to BART. This initial list was created based on historical information contained in the Division"s source files and is based on the 1962-1977 time frame and source category list contained in Appendix Y. This list was then examined to see if any of the sources identified would be exempt from BART. EPA allows sources to be exempt from BART if they have undergone permitted reconstruction, emit *de minimis* levels of pollution, or are fossil-fuel boilers with an individual heat input rating below 250 million Btu/hour. Colorado"s BART rule allows sources to be exempt from BART if modeling demonstrates the impact at any Class I area is below the "cause or contribute" thresholds of 1.0 and 0.5 deciviews. Table 6 - 3 lists the current status of the original BART sources and notes which sources were exempted and why.

Table 6 - 4 Colorado's BART Eligible Sources

Plant Name	Source Owner	Rating, Heat Input or Source type	Start Year	Current Status
Cemex - Lyons Kiln	Cemex	Portland Cement	<1977	Subject-to-BART
Cemex - Lyons Dryer	Cemex	Portland Cement	<1977	Subject-to-BART
CENC Unit 4	Colorado Energy Nations Company (CENC)	360 MMBtu/hr	1975	Subject-to-BART
CENC Unit 5	CENC	650 MMBtu/hr	1979	Subject-to-BART
Cherokee Unit 4	Public Service Company of Colorado (PSCO)	350 MW	1968	Subject-to-BART
Comanche Unit 1	PSCO	350 MW	1973	Subject-to-BART
Comanche Unit 2	PSCO	350 MW	1976	Subject-to-BART
Craig Unit 1	Tri-State Generation and	446 MW	1979	Subject-to-BART

Table 6 - 4 Colorado's BART Eligible Sources				
Plant Name	**Source Owner**	**Rating, Heat Input or Source type**	**Start Year**	**Current Status**
	Transmission, Inc.			
Craig Unit 2	Tri-State	446 MW	1979	Subject-to-BART
Hayden Unit 1	PSCO	190 MW	1965	Subject-to-BART
Hayden Unit 2	PSCO	275 MW	1976	Subject-to-BART
Martin Drake Unit 5	Colorado Springs Utilities (CSU)	55 MW	1962	Subject-to-BART
Martin Drake Unit 6	CSU	85 MW	1968	Subject-to-BART
Martin Drake Unit 7	CSU	145 MW	1974	Subject-to-BART
Pawnee Unit 1	PSCO	500 MW	1981	BART Alternative
Valmont Unit 5	PSCO	188 MW	1964	Subject-to-BART
Denver Steam Unit 1	PSCO	Steam only 210 MMBtu/hr	1972	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Denver Steam Unit 2	PSCO	Steam only 243 MMBtu/hr	1974	Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110
Holcim Kiln	Holcim	Portland Cement	<1977	Not subject-to-BART since Kiln built after BART time period. Other sources < 250 TPY total emissions.
Lamar Utilities	City of Lamar	25 MW	1972	Plant will be shutdown; so will no longer be subject.
Oregon Steel	Oregon Steel	Steel Mfg.	<1977	Not subject-to-BART since Arc furnace rebuilt after BART time period. Other sources < 250 TPY total emissions.
Ray Nixon Unit 1	CSU	227 MW	1980	Not Subject-to-BART (enforceable emission limitations and refined CALPUFF modeling result in less than 0.5 dv visibility impact)
Roche	Roche	Pharmaceutical Mfg.	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO
Suncor/Valero	Suncor	Refinery	<1977	Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO

(ii) *A determination of BART for each BART-eligible source.*

Table 6 - 2 lists the state"s BART determinations for sources that cause or contribute to visibility impairment in Class I areas.

(iii) *The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Summaries of the state"s facility-specific consideration of the five factors and resulting determinations are provided in this chapter 6. Documentation reflecting the state"s analyses and supporting the state"s BART determinations, including underlying data and detailed descriptions of the state"s analysis for each facility, are provided in Appendix C of this document.

(iv) *The determination of BART for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations Under the Regional Haze Rule).*

Colorado has only one source with two BART eligible EGUs that have a combined rating exceeding 750 MW, which is Tri-State Generation and Transmission Association"s Craig plant located in Moffat County. The Division"s BART determination for the Craig facility is discussed in more detail below.

(v) *A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.*

This requirement is addressed in Colorado"s BART Rule, and Regulation No. 3 Part F Section VI.

(vi) *A requirement that each source subject-to-BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained.*

Operation and maintenance plans are required by the BART Rule, and Regulation No. 3. Part F Section VII.

6.4.3 Overview of the BART Determinations and the Five Factor Analyses for Each BART Source

This section presents an overview of the BART determinations for the subject to BART sources.

The Regional Haze rule requires states to make determinations about what is appropriate for BART, considering the five statutory factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and

(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

The rule gives the states broad latitude on how the five factors are to be considered to determine the appropriate controls for BART. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the five factors in reaching a determination.[8] The manner and method of consideration is left to the state"s discretion; states are free to determine the weight and significance to be assigned to each factor.[9]

For the purposes of the five factor review for the three pollutants that the state is assessing for BART, SO2 and PM have been assessed utilizing the five factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on BART electric generating units, for reasons described below, the state is employing guidance criteria to aid in its assessment and determination of BART using the five factors for these sources, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of BART for these sources.

With respect to SO2 emissions, there are currently ten lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[10] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. Each of these systems will meet EPA"s presumptive limits, and in some cases surpass those limits.[11] The

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[8] The EPA "BART Guidelines" provide information relating to implementation of the Regional Haze rule, which the state has considered. However, Colorado also notes that Appendix Y is expressly not mandatory with respect to EGUs of less than 750 MWs in size, and Craig Station (Tri-State Generation and Transmission) is the only such BART electric generating unit in the state. *See* 70 Fed. Reg. at 39108. Thus, the state has substantial discretion in how it considers and applies the five factors (and any other factors that it deems relevant) to BART electric generating units in the state that are below this megawatt threshold, and for non-EGU sources. *See, e.g., id.* at 39108, 39131 and 39158.

[9] *See, e.g.*, 70 Fed. Reg. at 39170.

[10] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

[11] In preparing Appendix Y, EPA conducted extensive research and analysis of emission controls on BART sources nationwide, including all BART EGU sources in Colorado. *See* 70 Fed. Reg. at 39134. Based upon this analysis, EPA established presumptive limits that it deems to be appropriate for large EGU sources of greater than 750 MW, including sources greater than 200 MW located at such plants. EPA"s position is that the presumptive limits are cost effective and will lead to a significant degree of visibility improvement. *Id. See also,* 69 Fed. Reg. 25184, 25202 (May 5, 2004); *Technical Support Document for BART NOx Limits for Electric Generating Units* and *Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002-0076, April 15, 2006; *Technical Support Document for BART SO2 Limits for Electric Generating Units*,

Division has determined in the past that these systems can be cost-effective for Colorado"s BART sources, and the Air Quality Control Commission approved LSD systems as BART for Colorado Springs Utilities" Martin Drake Units #6 and #7 in 2008. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources, typically exceeding a control efficiency of 95%. The emission limits for these units reflect the 95% or greater control efficiency and are therefore stringent and appropriate. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado, and the Air Quality Control Commission approved these systems as BART in 2007. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations. Thus, as described in EPA"s BART Guidelines, a full five-factor analysis for PM emissions was not necessary for Colorado"s BART-subject units.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado at BART or other significant coal-fired electric generating units. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx BART controls for individual units for visibility improvement under the regional haze rule, the state has considered the five statutory factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight.[12] In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors. More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement

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Memorandum to Docket OAR 2002-0076, April 1, 2006; and *Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations*, U.S. EPA, June 2005.

[12] *See* 70 Fed. Reg. at 39170 and 39137.

expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

- Accordingly, as part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state"s calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state"s calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state"s general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of BART on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state"s extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado"s retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[13] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[14] The $5,000/ton criterion is also consistent and within the range of the state"s implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for regional haze, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, has the ability to provide significant NOx reductions, but also has initial capital dollar requirements that can

[13] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[14] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

approach or exceed $100 million per unit.[15] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[16] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[17] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the five factors under the Regional Haze rule, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

6.4.3.1 BART Determination for Cemex's Lyons Cement Plant

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. The Lyons plant was originally constructed with a long dry kiln. This plant supplies approximately 25% of the clinker used in the regional cement market. There are two BART eligible units at the facility: the dryer and the kiln.

In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO2 and NOx emissions. The raw material dryer emits minor amounts of SO2 and NOx; in 2008 Cemex reported SO2 and NOx emissions from the dryer as 0.89 and 10.41 tons per year respectively based on stack test results. Due to the low emission rates from the dryer the BART review focuses on the kiln.

Newer multistage preheater/precalciner kilns are designed to be more energy efficient and yield lower emissions per ton of clinker due to this when compared to the Cemex

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[15] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[16] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[17] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. The state relied upon this threshold when determining which Colorado"s BART eligible sources became subject to BART. *See*, Air Quality Control Commission Regulation No. 3, Section III.B.1.b. Thus, a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

Lyons kiln. The newer Portland cement plants studied by EPA, utilize multistage preheater/precalciner designs that are not directly comparable. Cemex has a unique single stage preheater/precalciner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalciner design with multiple stages to reduce emissions and energy requirements for the process. Additionally, new plant designs allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NOx to elemental Nitrogen.

Cemex submitted a BART analysis to the Division on August 1, 2006, with revisions submitted on August 28, 2006; January 15, 2007; October 2007 and August 29, 2008. In response to a Division request, Cemex submitted additional information on July 27 and 28, 2010

CALPUFF modeling provided by the source, using a maximum SO2 emission rate of 123.4 lbs/hour for both the dryer and kiln combined indicates a 98th percentile visibility impact of 0.78 delta deciview (Δdv) at Rocky Mountain National Park. The modeled 98th percentile visibility impact from the kiln is 0.76 Δdv. Thus, the visibility impact of the dryer alone is the resultant difference which is 0.02 Δdv. Because the dryer uses the cleanest fossil fuel available and post combustion controls on such extremely low concentrations are not practical, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable controls on the dryer. Accordingly, the state has determined that no additional emission control analysis of the dryer is necessary or appropriate since the total elimination of the emissions would not result in any meaningful visibility improvement which is a fundamental factor in the BART evaluation. For the dryer, the BART SO2 emission limitation is 36.7 tpy and the BART NOx emission limitation is 13.9 tpy, which are listed in the existing Cemex Title V permit.

SO2 BART Determination for Cemex Lyons - Kiln

Lime addition to kiln feed, fuel substitution (coal with tire derived fuel), dry sorbent injection (DSI), and wet lime scrubbing (WLS) were determined to be technically feasible for reducing SO2 emissions from Portland cement kilns.

The following table lists the most feasible and effective options:

Cemex Lyons -Kiln				
SO2 Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO2 Emissions (lbs/hr)	Annual Controlled SO2 Emissions (tpy)	Annual Controlled SO2 Emissions (lb/ton of Clinker)
Baseline SO2 Emissions		25.3	95.0	0.40
Lime Addition to Kiln Feed	25%	18.9	71.3	0.30
Fuel Substitution (coal with TDF)	40%	15.2	57.0	0.24

Cemex Lyons -Kiln				
SO2 Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO2 Emissions (lbs/hr)	Annual Controlled SO2 Emissions (tpy)	Annual Controlled SO2 Emissions (lb/ton of Clinker)
Dry Sorbent Injection	50%	12.6	47.5	0.20
Wet Lime Scrubbing (Tailpipe scrubber)	90%	2.5	9.5	0.04

The energy and non-air quality impacts of the alternatives are as follows:

- Lime addition to kiln feed and dry sorbent injection - there are no energy or non-air quality impacts associated with these control options
- Wet lime scrubbing - significant water usage, an additional fan of considerable horsepower to move the flue gas through the scrubber, potential increase in PM emissions and sulfuric acid mist
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.

There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex"s limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the SO2 emission reduction, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
SO2 Control Technology	SO2 Emission Reduction (tons/yr)	Annualized Cost ($/yr)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline SO2 Emissions	-			
Lime Addition to Kiln Feed	23.8	$3,640,178	$153,271	
Fuel Substitution (coal supplemented with TDF)	38.0	$172,179	$4,531	$243,368
Dry Sorbent Injection	47.5	Not provided	-	
Wet Lime Scrubbing (Tailpipe scrubber)	85.5	$2,529,018	$29,579	$49,618

The following table lists the projected visibility improvements for SO2 controls:

Cemex Lyons - Kiln		
SO2 Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max)	0.760	
Baseline (95 tpy)*	0.731	-
Lime Addition to Kiln Feed (71.3 tpy)*	0.727	0.033
Fuel Substitution (57 tpy)*	0.725	0.034
Dry Sorbent Injection (47.5 tpy)*	0.725	0.036
Wet Lime Scrubbing (9.5 tpy)*	0.720	0.040

** Visibility impacts rescaled from original BART modeling*

For the kiln, based upon its consideration and weighing of the five factors, the state has determined that no additional SO2 emissions control is warranted as the added expense of these controls were determined to not be reasonable for the small incremental visibility improvement of less than 0.04 deciviews. However, the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual BART SO2 emission limits for the kiln of:

25.3 lbs/hour and

95.0 tons of SO2 per year

No additional controls are warranted because 80% of the sulfur is captured in the clinker, making the inherent control of the process the SO2 control. Additional SO2 scrubbing is also provided by the limestone coating in the baghouse as the exhaust gas passes through the baghouse filter surface.

SO2 BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the SO2 BART requirement is 36.7 tpy, which is taken from the existing Title V permit.

Particulate Matter BART Determination for Cemex Lyons - Kiln and Dryer

The state has determined that the existing fabric filter baghouses and the existing regulatory emissions limits of 0.275 lb/ton of dry feed and 20% opacity for the kiln and 10% opacity for the dryer represent the most stringent control option. The kiln and dryer baghouses exceed a PM control efficiency of 95%, and the emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limits can be achieved through the operation of the existing fabric filter baghouse.

NOx BART Determination for Cemex Lyons - Kiln

Water injection, firing coal supplemented with tire-derived fuel (TDF), indirect firing with low NOx burners, and selective non-catalytic reduction (SNCR) were determined to be technically feasible and appropriate for reducing NOx emissions from Portland cement

kilns. As further discussed in Appendix C, the state has determined that SCR is not commercially available for Portland cement kilns. Presently, SCR has not been applied to a cement plant of any type in the United States. Cemex notes that the major SCR vendors have indicated that SCR is not commercially available for cement kilns at this time. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe, constitutes "available" control technology for purposes of BART. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is "available" for purposes of retrofitting such control technology on an existing source. Accordingly, the state has eliminated SCR as an available control technology for purposes of BART. Moreover, as further discussed in Appendix C, if SCR were considered commercially available, it is not technically feasible for the Lyons facility due to the unique design of the kiln.

The following table lists the most feasible and effective options:

Cemex Lyons - Kiln				
NOx Control Technology	Estimated Control Efficiency	Annual Controlled Hourly NOx Emissions (lbs/hr)	Annual Controlled NOx Emissions (tpy)	Annual Controlled NOx Emissions (lb/ton of Clinker)
Baseline NOx Emissions	-	464.3	1,747.1	7.39
Water Injection	7.0%	431.8	1,624.8	6.87
Coal w/TDF	10.0%	417.8	1,572.3	6.65
Indirect Firing with LNB	20.0%	371.4	1,397.6	5.91
SNCR (30-day rolling)	45.0%	255.3	960.9	4.06
SNCR (12-month rolling)	48.4%	239.4	901.0	3.81
SNCR w/LNB	55%	208.9	786.2	3.33

The energy and non-air quality impacts of the alternatives are as follows:

- Low-NOx burners - there are no energy or non-air quality impacts
- Water injection - significant water usage
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.
- SNCR - none

There are no remaining useful life issues for the alternatives as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex"s limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Cemex Lyons - Kiln				
NOx Control Technology	NOx Emission Reduction	Annualized Cost	Cost Effectiveness	Incremental Cost Effectiveness
	(tons/yr)	($/yr)	($/ton)	($/ton)
Baseline NOx Emissions	-			
Water Injection	122.3	$43,598	$356	-
Coal w/TDF	174.7	$172,179	$986	$2,453
Indirect Firing with LNB	349.4	$710,750	$2,034	$3,083
SNCR (45.0% control)	786.2	$1,636,636	$2,082	$2,120
SNCR (48.4% control)	846.1	$1,636,636	$1,934	$1,864
SNCR w/LNB (55.0% control w/uncertainty)	960.9	$1,686,395	$1,755	$434

The following table lists the projected visibility improvements for NOx controls for the kiln:

Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (from 24-hr Max) (Δdv)
24-hr Maximum (≈ 656.9 lbs/hr))	0.760	
Revised Baseline (≈ 464.3 lbs/hr)*	0.572	0.188
Original Baseline (≈ 446.8 lbs/hr)*	0.555	0.205
Water Injection (≈ 431.8 lbs/hr)*	0.540	0.220
Firing TDF (≈417.9 lbs/hr)*	0.526	0.234
Indirect Firing with LNB (≈ 371.4 lbs/hr)*	0.481	0.279
Original BART Limit – SNCR (≈ 268.0 lbs/hr)	0.380	0.380
Proposed BART Limit (30-day) – SNCR (≈ 255.3 lbs/hr)**	0.368	0.392
Proposed BART Limit (annual) – SNCR (≈ 239.0 lbs/hr)**	0.352	0.408
SNCR w/LNB (≈208.9 lbs/hr)**	0.322	0.438

The Cemex – Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system (>1500°F) is significantly higher at the exit than a more typical preheater precalciner kiln (650°F). This is a significant distinction that limits the location and residence time available for an effective NOx control system. The combination of SNCR with LNB has an uncertain level of control due to unique nature of the Lyons kiln. Furthermore, the associated incremental reduction in NOx emissions associated with SNCR in combination with LNB would afford only a minimal

or negligible visibility improvement (less than 0.03 delta deciview). Therefore, the Division believes that SNCR is the best NOx control system available for this kiln.

For the kiln, because of the unique characteristics of the Cemex facility, the state has determined that the BART emission limits for NOx are:

255.3 pounds per hour (30-day rolling average) and

901.0 tons per year (12-month rolling average)

The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This BART determination affords the most NOx reduction from the kiln (846.1 tpy) and contributes significant visibility improvement (0.38 Δdv). The determination affirms a prior Air Quality Control Commission BART determination for SNCR for this facility (2008). The state assumes that the BART emission limits can be achieved through the installation and operation of SNCR.

NOx BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the NOx BART requirement is 13.9 tpy, which is taken from the existing Title V permit.

A complete analysis that further supports the BART determination for the Cemex Lyons facility can be found in Appendix C.

6.4.3.2 BART Determination for Colorado Energy Nations Company (CENC)

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in its “NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado” Submittal provided on November 16, 2009, as well as additional information upon the Division‟s request on February 8, 2010, and May 7, 2010.

The CENC facility includes two coal-fired boilers that supply steam and electrical power to Coors Brewery. The boilers are rated as follows: Unit 4 at 360 MMBtu/hr and Unit 5 at 650 MMBtu/hr. These are approximately equivalent to 35 and 65 MW power plant boilers, based on the design heat rates.

SO2 BART Determination for CENC - Boilers 4 and 5

Dry sorbent injection (DSI) and SO_2 emission management were determined to be technically feasible for reducing SO2 emissions from Boilers 4 and 5. These options were considered as potentially BART by the Division. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically

feasible. SO2 emissions management uses a variety of options to reduce SO2 emissions: dispatch natural gas-fired capacity, reduce total system load, and/or recue coal firing rate to maintain a new peak SO2 limit.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SO_2 Emissions Management	1.0	$44,299	$43,690
DSI – Trona	468.0	$1,766,000	$3,774

CENC Boiler 5 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SO_2 Emissions Management	0.8	$65,882	$78,095
DSI – Trona	844.0	$2,094,000	$2,482

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, and fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to DSI are as follows:

SO2 Control Method	CENC - Boiler 4		CENC - Boiler 5	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.90		0.98	
DSI – Trona (annual avg.)	0.26	0.08	0.29	0.13

SO2 emissions management was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement that would result from one tpy or less of SO2 reduction.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)
CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

Particulate Matter BART Determination for CENC - Boilers 4 and 5

The Division has determined that for Boilers 4 and 5, an emission limit of 0.07 lb/MMBtu (PM/PM10) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for CENC - Boilers 4 and 5

Low NOx burners (LNB), LNB plus separated overfire air (SOFA), selective non-catalytic reduction (SNCR), SNCR plus LNB plus SOFA, and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at CENC Boilers 4 and 5.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 4 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	0	$0
LNB	59.9	$193,433	$3,227
SNCR	179.8	$694,046	$3,860
LNB+SOFA	209.8	$678,305	$3,234
LNB+SOFA + SNCR	368.0	$1,372,351	$3,729
SCR	515.4	$4,201,038	$8,150

CENC Boiler 5 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	48.4	$249,858	$5,166
LNB+SOFA	127.3	$815,829	$6,383
SNCR	207.3	$923,996	$4,458
LNB+SOFA + SNCR	353.7	$1,739,825	$4,918
SCR	550.0	$6,469,610	$11,764

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant
- LNB + SOFA – may increase unburned carbon in the ash, commonly referred to as loss on ignition
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	CENC - Boiler 4		CENC - Boiler 5	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx l Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.67		0.66	
LNB (annual avg.)	0.45	0.05	0.30	0.17
SNCR (annual avg.)	0.35	0.07	0.24	0.21
LNB + SOFA (annual avg.)	0.32	0.08	0.24	0.21
LNB + SOFA + SNCR (annual avg.)	0.19	0.12	0.17	0.26
SCR	0.07	0.18	0.07	0.31

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 4 is the following NOx emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air. Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not

substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SNCR and 0.10 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Unit 4.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 5 is the following NOx emission rates:

CENC Boiler 5: 0.19 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits above, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed above in section 6.4.3.

- Boiler 5: $4,918 per ton NOx removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in section 6.4.3.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.05 dv). Thus, it is not warranted to select emission limits associated SCR for CENC Unit 5.

A complete analysis that supports the BART determination for the CENC facility can be found in Appendix C.

6.4.3.3 BART Determination for Public Service Company Comanche Units 1 and 2

Comanche Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. PSCo submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8,

2007. In response to a Division request, PSCo submitted additional information on May 25, and July 14, 2010.

SO2 BART Determination for Comanche - Units 1 and 2

Semi-Dry FGD Upgrades – As discussed in EPA"s BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades should be considered for Comanche Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Comanche"s dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Comanche, the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO_2 removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO_2. Since NO_2 is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO_2 removal rates, such as those experienced at Comanche. There are no known acceptable reagents without this side effect that would allow additional SO_2 removal in the dry scrubbing systems present at the Comanche Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system* - The supplier offers no upgrade in atomizer design to improve SO_2 removal at Comanche. PSCo asserts and the state agrees that a third scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers.
- *Additional equipment and maintenance* - Comanche Units 1 and 2 are already achieving 30-day average emission rates of 0.12 lbs/MMBtu, 30-day rolling average, and 0.10 lbs/MMBtu, 12-month average for the two units combined, as adopted in 2007 by the Commission. It is not technically feasible to install an extra scrubber module at the site; therefore no additional equipment or maintenance will decrease SO2 emissions or achieve a lower limit.

Consequently, further capital upgrades to the current high performing SO2 removal system were deemed technically infeasible, and a lower emissions limit is not achievable.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Comanche – Unit 1		Comanche – Unit 2	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.75		0.74	
Semi-Dry FGD (LSD) (annual avg.)	0.12	0.35	0.12	0.33
Semi-Dry FGD (LSD) (annual avg.)	0.08	0.37	0.08	0.36

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that the following existing SO2 emission rates are BART:

Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling SO2 limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology. A complete analysis that supports the BART determination for the Comanche facility can be found in Appendix C.

Particulate Matter BART Determination for Comanche - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for PM/PM_{10}. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM_{10} as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Comanche - Units 1 and 2

SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Comanche Unit 1, and only SCR was determined feasible at Unit 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Comanche Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	445.6	$1,624,100	$3,644
SCR	770.4	$12,265,014	$15,290

Comanche Unit 2 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SCR	1,480	$14,650,885	$9,900

The energy and non-air quality impacts of the alternatives are as follows:

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Comanche – Unit 1		Comanche – Unit 2	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (1-yr) using new LNBs	0.20		0.20	
SNCR (annual avg.)	0.10	0.11	Not Feasible	–
SCR (annual avg.)	0.07	0.14	0.07	0.17

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following existing NOx emission rates:

Comanche Unit 1: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing low NOx burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the State's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.10 dv for SNCR and 0.13 dv for SCR for Unit 1, and 0.17 dv for SCR for Unit 2). SNCR was found not to be technically feasible for Comanche Unit 2. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Comanche Units 1 and 2.

A complete analysis that supports the BART determination for PSCo"s Comanche Units 1 and 2 can be found in Appendix C.

6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 BART Determination for Craig - Units 1 and 2

Wet FGD Upgrades – As discussed in EPA"s BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings:* TriState determined that installation of perforated trays, described below, accomplished the same objective.
- *Installation of perforated trays:* Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives:* Organic acid additives were considered but not selected for the following reasons:
    1. Dibasic Acid (DBA) has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.
    2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.

3. Installation of the perforated plate tray accomplished the same objective of increased SO_2 removal.

- *Improve or upgrade scrubber auxiliary equipment:* 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:
  1. Two vertical ball mills were installed for additional limestone processing capability for increased SO_2 removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO_2 removal rates.
  2. Forced oxidation within the SO_2 removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
  3. A ventilation system was installed for each reaction tank.
  4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
  5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
  6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO_2 removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
  7. Instrumentation and controls were modified to support all of the new equipment.
- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling SO_2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO2

limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 1		Craig – Unit 2	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.17		0.16	
Wet FGD	0.11	0.03	0.11	0.03
Wet FGD	0.07	0.05	0.07	0.05

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 1: 0.11 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

Particulate Matter BART Determination for Craig - Units 1 and 2

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10.}$ The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

NOx BART Determination for Craig - Units 1 and 2

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$3,797,000	$4,877
SCR	3,855	$25,036,709	$6,445

Craig Unit 2 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	806	$3,797,000	$4,712
SCR	3,975	$25,036,709	$6,299

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Craig – Unit 1		Craig – Unit 2	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.35		0.35	
SNCR	0.24	0.31	0.23	0.31
SCR	0.07	1.01	0.07	0.98

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART Alternative determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.27 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.27 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of SNCR. For the BART emission limits at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $4,877 per ton NOx removed; 0.31 deciview of improvement
- Unit 2: $4,712 per ton NOx removed; 0.31 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing

emissions. Although emission limits associated with SCR achieve better emissions reductions, the cost-effectiveness of SCR for this BART determination was determined to be excessive and above the cost guidance criteria presented above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

Per Section 308(e)(2) of EPA"s Regional Haze Rule, as an alternative to BART (or "BART alternative") it was proposed and the state agreed to a more stringent NOx emissions control plan for these BART units that consists of emission limits assumed to be associated with the operation of SNCR for Unit 1 and the operation of SCR for Unit 2. These NOx emission rates are as follows:

Craig Unit 1: 0.28 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.08 lb/MMBtu (30-day rolling average)

Unit 1"s 0.28 lb/MMBtu NOx emission rate equates to a 14% control and a NOx reduction of 727 tons per year, which is slightly less than the 15% control and a NOx reduction of 779 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

Unit 2"s 0.08 lb/MMBtu NOx emission rate equates to a 74% control and a NOx reduction of 3,975 tons per year, which is much greater than the 15% control and a NOx reduction of 806 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

The total NOx emission reduction resulting from the BART determination is 1,585 tons per year (779 + 806 = 1,585 tons per year). The total NOx emission reduction resulting from the BART Alternative is 4,702 tons per year (727 + 3,975 = 4,702 tons per year). Given the far greater emission reduction achieved by the BART Alternative when compared to the BART determinations for the individual units, the state determines, in accordance with the federal Regional Haze regulations, that the BART Alternative emission rates are appropriate for Craig Units 1 and 2 as providing greater reasonable progress than the application of BART as set forth in the federal BART Alternative regulation.

The state also evaluated the NOx emission reduction associated with both units (Craig 1 & 2) in contrast to the existing NOx rates, presumptive BART NOx rate, source-by-source determination, and the final RH determination to determine the total NOx reduction benefit. In the below table, the existing NOx emissions from both units is 10,562 tons/year which is much lower than the existing presumptive BART emissions of 14,849 tons/year. The source-by-source BART determination resulted in NOx emissions of 8,978 tons/year which is well above the 5,860 tons/year in NOx emissions calculated to result from application of the BART Alternative. These tons/year calculations provide an emissions based comparison to demonstrate that the Craig BART Alternative provides greater reasonable progress than, and is superior to, source by source BART for these units. The table below is illustrative for demonstration purposes only. The tons per year projections provide an emission based comparison and are not enforceable requirements.

NOx Analysis	Units	Craig 1	Craig 2	Total
Annual Average Heat Input*	*[MMBtu]*	36,933,572	39,214,982	
Annual Average NOx Rate*	*[lb/MMBtu]*	0.28	0.27	
Annual Average NOx Emissions*	*[tons/year]*	5,190.3	5,371.6	10,562
Presumptive NOx Rate	*[lb/MMBtu]*	0.39	0.39	
Presumptive NOx Emissions	*[tons/year]*	7,202.1	7,646.9	14,849
Source-by-Source Determination	*[lb/MMBtu]*	0.27	0.27	
Source-by-Source Determination	*[tons/year]*	4,411.8	4,565.9	8,978
Final Regional Haze Determination	*[lb/MMBtu]*	0.28	0.08	
Final Regional Haze Determination	*[tons/year]*	4,463.7	1,396.6	5,860

** Data from CAMD used for period (2006-2007)*

Based on the above analysis and demonstration, the BART Alternative (final RH determination) achieves more NOx emissions reductions, which are well below the source-by-source BART determinations for each unit. Consequently, the BART Alternative will result in more visibility improvement at nearby Class I areas, and the state adopts this BART Alternative as appropriate to comply with the Regional Haze rule for these units. The state notes that this BART Alternative is not a trading program per Section 308(e)(2) and provisions associated with trading are not applicable.

Under EPA"s Alternative to BART rule (40 CFR § 51.308(e)(2)), a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration addresses these requirements, as follows. (A complete description of these federal requirements is presented in section 6.4.3.7 below.)

1) *51.308(e)(2)(i)(A)* A listing of all BART-eligible sources can be found in Table 6-3 above.
2) *51.308(e)(2)(i)(B)* The two BART-eligible sources are Craig Units 1 and 2.
3) *51.308(e)(2)(i)(C)* The BART determinations presented herein describe the control information and the projected total NOx reduction of 1,585 tons per year for source-by-source BART.
4) *51.308(e)(2)(i)(D)* The BART Alternative achieves a projected NOx reduction of 4,702 tons per year.
5) *51.308(e)(2)(i)(E)* The BART Alternative achieves more than 3,100 tons of projected NOx reduction per year over what would be achieved by the installation of BART.
6) *51.308(e)(2)(iii)* The Craig BART Alternative will be implemented as expeditiously as practicable but no later than five years after EPA"s approval of this BART Alternative, as required by Regulation No. 3 Part F. The regulation requires that a compliance schedule be developed by the source and submitted to the state within six months from EPA"s approval. The compliance and

monitoring provisions of the BART Alternative have also been incorporated into Regulation No. 3, Part F.

7) *51.308(e)(2)(iv)* The emission reductions associated with the Craig BART Alternative have not been used for other SIP purposes, thus they are surplus.

8) *51.308(e)(2)(v)* The state is not proposing a geographic enhancement for reasonably attributable impairment.

9) *51.308(e)(2)(vi)* Since Colorado is not using a trading program for the Craig BART Alternative, this section does not apply.

10) *51.308(e)(3)* There are only two units at the same facility under the Craig BART Alternative and thus there is no change in the distribution of emissions than under BART, and, as stated above, the alternative measure results in greater emission reductions than case-by-case BART. Therefore the Craig BART Alternative is deemed to achieve greater reasonable progress.

11) *51.308(e)(3)(i)* Since the Craig BART Alternative includes only two units at the same facility, the state has determined that visibility does not decline in any Class I area due to the Craig BART Alternative when compared to case-by-case BART.

12) *51.308(e)(3)(ii)* Because the Craig BART Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART, the state determines that there will be an overall improvement in visibility over all affected Class I areas.

13) *51.308(e)(4)* Colorado is not participating in the CAIR program and cannot rely on this program for the Craig BART Alternative.

14) The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

15) *51.308(e)(6)* No Colorado BART sources have applied for an exemption from BART.

A complete analysis that supports the BART determination and BART Alternative for Craig Station Units 1 and 2, including substantial cost information for NOx controls, can be found in Appendix C.

6.4.3.5 BART Determination for Public Service Company's Hayden Station

Hayden Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to a Division request, PSCo submitted additional information on May 25, 2010.

SO2 BART Determination for Hayden - Units 1 and 2

Semi-Dry FGD Upgrades – As discussed in EPA"s BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades were considered for Hayden Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Hayden"s dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Hayden, the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO_2 removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO_2. Since NO_2 is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO_2 removal rates, such as those experienced at Hayden. This side effect is unacceptable in a region with numerous Class I areas in close proximity to the source. There are no known acceptable reagents without this side effect that would allow additional SO_2 removal in the dry scrubbing systems present at Hayden Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system* - The supplier offers no upgrade in atomizer design to improve SO_2 removal at Hayden. However, an additional scrubber module could be added along with spare parts and maintenance personnel in order to meet a lower emission limit. This option is technically feasible.
- *Additional equipment and maintenance* - Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit than the 2008 State-adopted BART emission limit of 0.16 lbs/MMBtu by purchasing additional spare atomizer parts and increasing annual operating and maintenance through increased labor and reagent requirements. This emissions limit is 0.13 lbs/MMBtu, which is the current rolling 90-day limit.

The additional scrubber module, and additional spare atomizer parts with additional operation and maintenance were determined to be technically feasible for reducing SO2 emissions from Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Semi-Dry FGD Upgrade – Additional Equipment and Maintenance	61	$141,150	$2,317
Additional Scrubber Module	488	$4,142,538	$8,490

Hayden Unit 2 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Semi-Dry FGD Upgrade – Additional Equipment and Maintenance	39	$141,150	$3,626
Additional Scrubber Module	589	$4,808,896	$8,164

The additional scrubber module option was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement (less than 0.1 deciview) that would result from this upgrade.

There are no energy and non-air quality impact associated with the remaining semi-dry FGD upgrade alternative (additional equipment and maintenance).

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Hayden – Unit 1		Hayden – Unit 2	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.34		0.40	
Existing Semi-Dry FGD (LSD) (annual avg.)	0.16	0.09	0.16	0.18
Semi-Dry FGD Upgrade (annual avg.)	0.13	0.10	0.13	0.21
Additional Scrubber Module (annual avg.)	0.07	0.14	0.07	0.26

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)
Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling SO2 limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

Particulate Matter BART Determination for Hayden - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and Unit 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for PM/PM_{10}. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM_{10} as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Hayden - Units 1 and 2

LNB upgrades, SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Hayden Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Hayden Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	1,391	$572,010	$411
SNCR	1,391	$1,353,500	$973
SCR	3,120	$10,560,612	$3,385

Hayden Unit 2 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
LNB	1,303	$992,729	$762
SNCR	1,610	$1,893,258	$1,176
SCR	3,032	$12,321,491	$4,064

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Hayden – Unit 1		Hayden – Unit 2	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.61		0.37	
LNB (annual avg.)	0.26	0.69	0.21	0.40
SNCR (annual avg.)	0.26	0.69	0.18	0.48
SCR (annual avg.)	0.07	1.12	0.06	0.85

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)
Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $3,385 per ton NOx removed; 1.12 deciview of improvement
- Unit 2: $4,064 per ton NOx removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NOx emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.

A complete analysis that supports the BART determination for PSCo"s Hayden Units 1 and 2 can be found in Appendix C.

6.4.3.6 BART Determination for Colorado Springs Utilities' Martin Drake Plant

Colorado Springs Utilities" Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division

demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in its "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 as well as additional information upon the Division"s request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010.

SO2 BART Determination for Martin Drake - Units 5, 6 and 7

Dry sorbent injection (DSI) was determined to be feasible for all units and dry FGD were determined to be technically feasible for reducing SO2 emissions from Units 6, and 7. These options were considered as potential BART level controls by the Division. Lime or limestone-based wet FGD system is also technically feasible but was determined to be not reasonable due to adverse non-air quality impacts. Drake is conducting a trial on a new wet FGD system design (NeuStream-S) that uses much less water along with a smaller operational footprint that may provide, if successfully demonstrated, a reasonable alternative to traditional wet FGD systems.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	762	$1,340,663	$1,760

Drake Unit 6 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	1,671	$2,910,287	$1,741
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	2,284	$6,186,854	$2,709
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	2,368	$6,647,835	$2,808
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	2,507	$7,452,788	$2,973

Drake Unit 7 - SO_2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI	2,657	$3,723,826	$1,405
Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average)	3,632	$8,216,863	$2,263
Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average)	3,764	$8,829,321	$2,345
Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average)	3,986	$9,898,382	$2,483

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Drake – Unit 5		Drake – Unit 6		Drake – Unit 7	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.94		1.00		0.99	
DSI (annual avg.)	0.25	0.12	0.33	0.18	0.33	0.29
Dry FGD (LSD) (annual avg.)	Not feasible		0.12	0.24	0.12	0.39
Dry FGD (LSD) (annual avg.)	Not feasible		0.07	0.26	0.07	0.41

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 5 is the following SO2 emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

- Unit 5: $1,760 per ton SO2 removed; 0.12 deciview of improvement

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 6 and Unit 7 is the following SO2 emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)
Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSD). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

These emission rates for Units 6 and 7 provide 85% SO2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: $2,808 per ton SO2 removed; 0.24 deciview of improvement
- Unit 7: $2,345 per ton SO2 removed; 0.39 deciview of improvement

Particulate Matter BART Determination for Martin Drake - Units 5, 6 and 7

The state determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) for the three units represent the most stringent control options. The units are exceeding a PM control efficiency of 95%, and the emission limits are BART for $PM/PM_{10.}$ The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx BART Determination for Martin Drake - Units 5, 6 and 7

Ultra low NOx burners (ULNB), ULNB including OFA, SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Drake Units 5, 6 and 7.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Drake Unit 5 - NO_x Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	154	$141,844	$923
Ultra-low NOx burners (ULNBs)	200	$147,000	$736
ULNBs + OFA	215	$288,844	$1,342
Selective Non-Catalytic Reduction (SNCR)	231	$1,011,324	$4,387
ULNB/SCR layered approach	626	$4,467,000	$7,133
Selective Catalytic Reduction (SCR)	626	$4,580,000	$7,314

Drake Unit 6 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	283	$104,951	$371
Selective Non-Catalytic Reduction (SNCR)	424	$1,208,302	$2,851
Ultra-low NOx burners (ULNBs)	452	$232,800	$515
ULNBs + OFA	509	$337,751	$664
ULNB/SCR layered approach	1,175	$6,182,800	$5,260
Selective Catalytic Reduction (SCR)	1,175	$6,340,000	$5,395

Drake Unit 7 - NOx Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Overfire air (OFA)	416	$75,217	$181
Ultra-low NOx burners (ULNBs)	583	$386,000	$662
Selective Non-Catalytic Reduction (SNCR)	624	$2,018,575	$3,233
ULNBs + OFA	749	$461,217	$616
ULNB/SCR layered approach	1,709	$8,196,000	$4,797
Selective Catalytic Reduction (SCR)	1,709	$8,510,000	$4,981

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Drake – Unit 5		Drake – Unit 6		Drake – Unit 7	
	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.62		0.83		0.71	
OFA (annual avg.)	0.30	0.07	0.33	0.18	0.31	0.22
ULNB (annual avg.)	0.28	0.08	0.28	0.193	0.28	0.24
ULNB + OFA (annual avg.)	0.27	0.08	0.27	0.20	0.25	0.26
SNCR (annual avg.)	0.27	0.08	0.29	0.19	0.28	0.24
ULNB + SCR	0.07	0.12	0.07	0.27	0.07	0.37
SCR (annual avg.)	0.07	0.12	0.07	0.27	0.07	0.37

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOX BART for Units 5, 6 and 7 is the following NOx emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.29 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NOx burners (including over-fire air).

- Unit 5: $1,342 per ton NOx removed
- Unit 6: $664 per ton NOx removed
- Unit 7: $616 per ton NOx removed

The extremely low dollars per ton control costs leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement at all units do not meet the criteria guidance described above (*e.g.* less than 0.50 Δdv)

For Drake Units 5 and 6, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial

when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SCR on Unit 5 and 0.07 dv for SCR on Unit 6). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Units 5 and 6.

For Drake Unit 7, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.11 dv for SCR). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Unit 7.

A complete analysis that supports the BART determination for CSU"s Martin Drake Units 5, 6 and 7 can be found in Appendix C.

6.4.3.7 BART Determination for Public Service Company's Cherokee Unit 4, Valmont Unit 5 and the Pawnee Station as a BART Alternative, which Includes Reasonable Progress Determinations for Arapahoe Units 3 and 4 and Cherokee Units 1, 2 and 3

Background

Section 308(e)(2) of EPA"s Regional Haze Rule allows a state to approve a BART alternative:

> *A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such emission trading programs or other alternative measures, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses: (i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on the following: (A) A list of all BART-eligible sources within the State. (B) A list of all BART-eligible sources and all BART source categories covered by the alternative program. The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program, but each BART-eligible source in the State must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or paragraph (e)(1) of this section, or otherwise addressed under paragraphs (e)(1) or (e)(4) of this section.*

The PSCo BART Alternative Program (““PSCo BART Alternative”) was proposed by Public Service Company of Colorado (PSCo). The PSCo BART Alternative is not a trading program and does not include any complete source categories, although all facilities in the PSCo BART Alternative are electric generating units. The PSCo BART Alternative is based on reductions achieved as a result of a combination of unit shutdowns and the application of emissions controls planned as part of the Colorado HB 10-1365, the “Clean Air – Clean Jobs Act” (§ 40-3.2-201 C.R.S., *et. seq*.). The PSCo BART Alternative includes ten units at four facilities. The facilities included in the PSCo Alternative and the proposed controls are listed below.

Table 6-5: Actions and Dates under the PSCo Alternative

Facility	Unit	Action or Control	Effective Date
Arapahoe	Unit 3	Shutdown	12/31/2013
	Unit 4	Operation on Natural Gas only (peaking unit)	12/31/2014
Cherokee	Unit 1	Shutdown	No later than 7/1/2012
	Unit 2	Shutdown	12/31/2011
	Unit 3	Shutdown	No later than 12/31/2016
	Unit 4	Operation on Natural Gas only	12/31/2017
Valmont		Shutdown	12/31/2017
Pawnee		SCR & LSD	12/31/2014

The state in evaluating the PSCo Alternative followed the EPA July 6, 2005, BART guidelines and the EPA October 13, 2006, regulation referred to as Provisions Governing Alternative to Source-Specific BART Determinations (71Fed.Reg. 60612-60634 (10/13/2006); 40 CFR § 51.308(e)(2), “Alternative to BART rule”). Under the Alternative to BART rule, a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration must include five elements:

1) A list of all BART-eligible sources within the state;
2) A list of all BART-eligible sources and source categories covered by the alternative program;
3) An analysis of the best system of continuous emission control technology available and the associated reductions;
4) An analysis of the projected emissions reductions achievable through the alternative measure; and
5) A determination that the alternative measure achieves greater reasonable progress than would be achieved through the installation of BART.

The PSCo Alternative includes both BART and non-BART sources. The non-BART sources are older than the BART timeframe, and in effect will all be controlled and reduce their NOx and SO2 emissions as a result of enforceable facility retirement dates and, for one unit, operating only on natural gas as a “peaking” unit. The BART sources, Cherokee 4, Pawnee and Valmont, will all be either controlled within the first planning period or shutdown with enforceable facility retirement dates.

The state"s alternative program satisfies the requirements of 40 CFR § 51.308, as further described in the preambles to the BART guidelines and the Alternative to BART rule. The state"s analysis must include:

> *An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.*

40 CFR § 51.308(e)(2)(i)(C).

Colorado"s alternative program was designed to meet a requirement other than BART; namely, Colorado"s HB 10-1365. The express purpose of the legislation leading to the alternative program being proposed is:

> THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT THE FEDERAL "CLEAN AIR ACT", 42 U.S.C. SEC. 7401 ET SEQ., WILL LIKELY REQUIRE REDUCTIONS IN EMISSIONS FROM COAL-FIRED POWER PLANTS OPERATED BY RATE-REGULATED UTILITIES IN COLORADO. A COORDINATED PLAN OF EMISSION REDUCTIONS FROM THESE COAL-FIRED POWER PLANTS WILL ENABLE COLORADO RATE-REGULATED UTILITIES TO MEET THE REQUIREMENTS OF THE FEDERAL ACT AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT AT A LOWER COST THAN A PIECEMEAL APPROACH. A COORDINATED PLAN OF REDUCTION OF EMISSIONS FOR COLORADO'S RATE-REGULATED UTILITIES WILL ALSO RESULT IN REDUCTIONS IN MANY AIR POLLUTANTS AND PROMOTE THE USE OF NATURAL GAS AND OTHER LOW-EMITTING RESOURCES TO MEET COLORADO'S ELECTRICITY NEEDS, WHICH WILL IN TURN PROMOTE DEVELOPMENT OF COLORADO'S ECONOMY AND INDUSTRY.

§ 40-3.2-202, C.R.S. Similarly, Colorado"s Clean Air – Clean Jobs Act further specifies that it is intended to address both current and reasonably foreseeable future requirements of the federal Clean Air Act. *See,* § 40-3.2-204, C.R.S.

PSCo BART Alternative measure for the subject coal-fired electric generating units is thus designed to meet the requirements of the regional haze rule, including BART, but also to address requirements beyond BART. This includes, for example, a revised national standard for ozone to be promulgated in 2011, other revised or to be revised national ambient air quality standards, or federal sector-specific regulations for hazardous air pollutants, among other federal regulatory requirements. Accordingly, the state will determine whether the PSCo BART Alternative represents the best system of

continuous emission control technology and associated emission reductions for the sources included in the alternative. In the preamble to the Alternative to BART rule, EPA discusses whether the option exists for states to use simplifying assumptions in determining the BART benchmark, or whether states must establish the BART benchmark through a source-by-source BART analysis. EPA states:

> [T]here is no need to develop a precise estimate of the emissions reductions that could be achieved by BART in order simply to compare two programs. As EPA did in the CAIR, States should have the ability to develop a BART benchmark based on simplifying assumptions as to what the most-stringent BART is likely to achieve. The regulations finalized today therefore provide that where an emission trading program has been designed to meet a requirement other than BART, including the reasonable progress requirement, the State may establish a BART benchmark based on an analysis that includes simplifying assumptions about BART control levels for sources within a source category.

71 Fed. Reg. 60612, 60618 (October 13, 2006). EPA has thus determined that source-by source BART is not required when it is not necessary where a state has determined that greater reasonable progress can be achieved by an alternative means. *See also,* 70 Fed. Reg. 39104, 39137 (July 6, 2005). Thus, there is no need for states to conduct an extensive source-by-source BART assessment, and to then also go through the additional, resource intensive steps of developing an alternative program to BART. *See,* 71 Fed. Reg. at 60617.

Colorado has looked at several options to establish the BART benchmark. EPA establishes some criteria for the BART benchmark in the Alternative to BART rule, where the agency discusses simplifying assumptions.

> In today"s final rule, the regulations make clear that, with one exception, States must follow the approach for making BART determinations under section 51.308(e)(1) in establishing a BART benchmark. This includes the requirement for States to use the BART guidelines in making BART determinations for EGUs at power plants of a certain size. As discussed above, the one exception to this general approach is where the alternative program has been designed to meet requirements other than BART; in this case, States are not required to make BART determinations under § 51.308(e)(1) and may use simplifying assumptions in establishing a BART benchmark based on an analysis of what BART is likely to be for similar types of sources within a source category. Under either approach to establishing a BART benchmark, we believe that the presumptions for EGUs in the BART guidelines should be used for comparison to a trading program or other alternative measure, unless the State determines that such presumptions are not appropriate for particular EGUs.

71 Fed. Reg. at 60619 (October 13, 2006). *See also, id*. at 60615 ("Where a trading program or other similar alternative program has been designed primarily to meet a Federal or State requirement other than BART, the State can use a more simplified approach to demonstrating that the alternative program will make greater reasonable progress than BART. Such an approach may be appropriate where the State believes the alternative program is clearly superior to BART and a detailed BART analysis is not

necessary to assure that the alternative program will result in greater reasonable progress than BART.”).

The PSCo BART Alternative includes only EGUs and, based on EPA"s Alternative to BART rule, one option available is a comparison to the presumptive limits in the BART guidelines. *Id*. The presumptive limits represent a reasonable estimate of stringent case BART, particularly when developing a BART benchmark to assess an alternative program, because they are applied equally to EGU"s of varying size and distance from Class I areas, and with varying impacts on visibility. *Id.* Because not all of the sources in the PSCo BART Alternative are BART sources, the state also considered other benchmarks that might be appropriate. For example, as part of the BART and reasonable progress analysis, the state has established guidelines for NOx based on control technology costs and visibility improvements. The state"s analysis substantiates that the PSCo BART Alternative provides greater reasonable progress than would have been achieved without the alternative.

Analysis Under 40 CFR Part 51, § 308(e)

(2)(i)(A) A list of all Bart-eligible sources within the State.

A listing of all BART-eligible sources can be found in Table 6-3 in this Chapter 6 of the Regional Haze State Implementation Plan.

(2)(i)(B) A list of all BART-eligible sources and all BART source categories covered by the alternative program.

The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program. However, each BART-eligible source in the State covered by the PSCo BART Alternative in this case must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or section 308(e)(1), or otherwise be addressed under section 308(e)(1) or (e)(4). The BART sources covered by the PSCo BART Alternative are shown in Table 6-6.

Table 6-6: Sources Included Within the PSCo Alternative

Facility	Unit	Action or Control
Arapahoe	Unit 3	Shutdown
	Unit 4	Operation on natural gas only
Cherokee	Unit 1	Shutdown
	Unit 2	Shutdown
	Unit 3	Shutdown
	Unit 4 (BART-eligible)	Operation on natural gas only
	New nat. gas-fired EGU	BACT where netting does not apply
Valmont	(BART-eligible)	Shutdown
Pawnee	(BART-eligible)	SCR & LSD

(2)(i)(C) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.

The PSCo BART Alternative includes the emission reductions achieved through Colorado HB 10-1365 (§ 40-3.2-201 C.R.S., *et seq*.). The PSCo BART Alternative was developed to address requirements other than BART, including to support the attainment of federal ambient air quality standards, to meet other federal requirements that can affect electric generating units, and improve air quality on the Front Range of Colorado. Since the PSCo BART Alternative was designed to address requirements other than BART, it meets the EPA SIP provision noted above that allows the state to determine the base case BART emissions using simplifying assumptions. This approach is discussed in EPA"s Alternative to BART Rule. *See,* 71 Fed. Reg. at 60612 (October 13, 2006). Colorado has estimated base case BART emissions assuming that the plants included in the PSCo BART Alternative emit at the presumptive levels established by EPA for electric generating units of greater than 750 MW.[18] The emissions resulting from the PSCo BART Alternative are then compared to the analysis of base case BART emissions to indicate the degree of emissions reduction improvement provided by the PSCo BART Alternative.

(2)(i)(D) An analysis of the projected emissions reductions achievable through the trading program or other alternative measure.

The emission reductions achievable through PSCo"s Alternative include the reductions associated with the combination of shutdowns and retrofit controls established under PSCo"s emissions reduction plan, endorsed by the state Public Utilities Commission pursuant to HB 10-1365, and codified and made enforceable by the elements reflected in this State Implementation Plan. The following emissions reductions provided by the PSCo BART Alternative are reflected in Tables 6-7 and 6-8, below. With respect to SO2 emissions, the PSCo BART Alternative will reduce SO2 emissions from these units by 21,493 tons per

[18] None of the BART units included in this Alternative are larger than 750MW, thus the presumptive emissions standards for electric generating units set forth in EPA"s BART guidelines are not mandatory for these units. *See, e.g.,* 70 Fed. Reg. at 39108. The non-BART units included in this Alternative are also not subject to the presumptive emissions standards as a mandatory element of Regional Haze. While not required as a matter of regulation the presumptive limits are employed in this instance solely for demonstrative and comparative purposes.

year in the first planning period (2010 to 2018). With respect to NOx emissions, the PSCo BART Alternative will reduce NOx emissions from these units by 15,994 tons per year in the first planning period (2010 to 2018).

(2)(i)(E) A determination under paragraph (e)(3) of this section or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.

The PSCo BART Alternative has been evaluated according to the emissions based test discussed in EPA"s Alternative to BART Rule. This is explained in further detail below, and demonstrates that for both SO2 and NOx, due to a combination of substantial retirements of coal-fired units and controls on other coal-fired units, the PSCo BART Alternative provides greater reasonable progress than would be afforded under BART at the covered sources.

(2)(ii) [Reserved]

(2)(iii) A requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. To meet this requirement, the State must provide a detailed description of the emissions trading program or other alternative measure, including schedules for implementation, the emission reductions required by the program, all necessary administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.

The PSCo BART Alternative for these electric generating units will be implemented during the first long-term strategy period, by December 31, 2017. The PSCo BART Alternative as set forth in this SIP establishes an expeditious implementation schedule for the coordinated shutdown of, and installation of retrofit emissions controls on the covered coal-fired electric generating units. As reflected in Table 6-12, emission limits for SO2 and NOx at Pawnee, operation on natural gas at Cherokee Unit 4, operation on natural gas at Arapahoe Unit 4 as a peaking unit only, and shutdowns at Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont, will all occur during the first planning period. Some of the NOx emissions reductions will be reserved, and are not used in this alternative measure demonstration and not reflected in the emissions reductions in this SIP, to allow for natural gas replacement power at Cherokee and future “netting” or “offsets”. The compliance and monitoring provisions of the PSCo BART Alternative have been incorporated into Regulation No. 3, Part F. Compliance will be determined through the use of continuous emission monitors for those facilities that are not shutdown. Enforceability of the shutdown of coal-fired units under the PSCo BART Alternative is reflected in this State Implementation Plan, as well as in Regulation No. 3, Part F. Colorado will also amend the relevant permits to include enforceable shutdown dates.

(2)(iv) A demonstration that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.

The emission controls associated with the PSCo BART Alternative have not been used for other SIP purposes, thus they are surplus. The reductions from the

shutdown of Arapahoe units 1 and 2 were used in an earlier PM SIP demonstration and are not included in this analysis.

(2)(v) At the State's option, a provision that the emissions trading program or other alternative measure may include a geographic enhancement to the program to address the requirement under §51.302(c) related to BART for reasonably attributable impairment from the pollutants covered under the emissions trading program or other alternative measure.

The Division is not proposing a geographic enhancement for reasonably attributable impairment.

(2)(vi) For plans that include an emissions trading program that establishes a cap on total annual emissions of SO2 or NOx from sources subject to the program, requires the owners and operators of sources to hold allowances or authorizations to emit equal to emissions, and allows the owners and operators of sources and other entities to purchase, sell, and transfer allowances, the following elements are required concerning the emissions covered by the cap:

Since Colorado is not using a trading program for the PSCo BART Alternative, this section does not apply. Electric generating units subject to this alternative have unit-specific compliance requirements reflected in this SIP and in Reg. No. 3, Part F.

(3) A State which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, then the alternative measure may be deemed to achieve greater reasonable progress. If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met:

The Division has determined that the distribution of emissions under the PSCo BART Alternative is not substantially different than under BART, and the alternative measure results in greater emission reductions than case-by-case BART. The PSCo BART Alternative includes three BART units at four different facilities, all of which are in or immediately adjacent to the 8-Hour Ozone Non-Attainment Area in the Front Range of Colorado. Like the other three facilities, the fourth is the Arapahoe facility and it is central to the non-attainment area, and is only 17 kilometers from the Cherokee facility.

(3)(i) Visibility does not decline in any Class I area, and

Since the Metro Denver BART eligible sources are included in the PSCo BART Alternative along with other non–BART sources in the area, and the overall visibility-impairing pollutants from these units decrease substantially, the Division

has determined that visibility does not decline in any Class I area in relation to this PSCo BART Alternative.

(3)(ii) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.

The PSCo Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART. The reasons why the alternative provides greater reductions include:

a) Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont (BART eligible unit), will be shutdown during the first planning period.

b) Arapahoe Unit 4 will operate on natural gas as a peaking unit.

c) Cherokee Unit 4 (BART eligible unit) will operate on natural gas only.

d) Pawnee Unit 1(BART eligible unit) will install and operate an LSD to control SO2 emissions and SCR to control NOx emissions in 2014.

(4) A State that chooses to meet the emission reduction requirements of the Clean Air Interstate Rule (CAIR) by participating in one or more of EPA's CAIR trading programs

Colorado is not participating in the CAIR program.

(5) After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraph (d) of this section in the same manner as other sources.

The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

(6) Any BART-eligible facility subject to the requirement under paragraph (e) of this section to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement. An application for an exemption will be subject to the requirements of §51.303(a)(2)–(h).

No Colorado BART sources have applied for an exemption from BART.

Technical Analysis of the PSCo Alternative Emissions Reductions with Respect to the Section 308(e) Alternative Measure Demonstration

The following technical analysis of emissions reductions that result from the PSCo BART Alternative more fully demonstrates that the proposed alternative achieves greater reasonable progress than the installation of BART, as allowed under EPA"s regional haze regulations. EPA"s Regional Haze Rule requires that BART- eligible sources either install BART as determined for each source on a case-by-case basis, or install controls as required by a BART Alternative. EPA"s BART guidance (70 Fed. Reg. 39104, July 6, 2005) and EPA"s regulation on BART Alternatives (71 Fed. Reg. 60612, October 13, 2006) both provide guidance on how to evaluate whether a BART Alternative proposal achieves greater reasonable progress under the regulation. This determination can be made based on an emissions comparison or through a modeling analysis if the state determines that is appropriate. If the geographic distribution of

emissions reductions from the programs is expected to be similar, the comparison can be made based on emissions alone. 70 Fed. Reg. at 39136; 71 Fed. Reg. at 60620. Because all the sources included in the PSCo BART Alternative are located in the same air shed and within a 100 mile area, the Division has determined that the BART eligible sources in the PSCo BART Alternative are in the same geographic region (namely, in the Denver Metro Area and also in or immediately adjacent to the existing 8-Hour Ozone Non-Attainment Area) for purposes of regional haze. Thus an emissions demonstration is appropriate and modeling is not warranted for an alternative measure demonstration.

EPA"s BART guidance does not specify a quantity of emission reductions an alternative must exceed to satisfy the "achieves greater reasonable progress" criteria. In its BART guidance, EPA provides an emission-based demonstration of how EPA determined the Clean Air Interstate Rule (CAIR) to be better than case-by-case BART on individual sources. In that instance, EPA demonstrated that more tons of emission reductions would result from the CAIR rule than with source-by-source BART. *See, e.g.,* 70 Fed. Reg. at 39141. Similarly, the state has utilized the emission-based method to evaluate the PSCo BART Alternative. The state has determined that the PSCo BART Alternative achieves greater reasonable progress by evaluating the future emissions from the electric generating units under the operating scenarios reflected in the PSCo BART Alternative, and for demonstration purposes compared those emissions with the same units using the standard established by EPA of 95 percent removal or 0.15 lb/MMBtu for SO2 or a lb/MMBtu for NOx based on boiler and coal type. *See* 71 Fed. Reg. at 60619 ("States establishing a BART benchmark based on simplifying assumptions as to the most stringent BART for EGUs may rely on the presumptions, as EPA did in the CAIR rule.").

As previously discussed, the PSCo Alternative is based on a combination of emissions control retrofits and shutdowns resulting from Colorado HB 10-1365 and the PUC"s actions. The PSCo BART Alternative includes Pawnee, Arapahoe Units 3 and 4, Valmont Unit 5, and Cherokee Units 1-4. Pawnee, Cherokee Unit 4 and Valmont Unit 5 are the only BART eligible units. The sources involved in the PSCo BART Alternative are either BART eligible sources or sources that precede the BART timeframe. For demonstration purposes, the emissions from the entire group of electric generating units in the PSCo BART Alternative were compared to the emissions from the units if the presumptive levels were applied, as allowed under EPA"s regulation. Table 6-7 compares the tons of SO2 that would be emitted under the PSCo BART Alternative to the number of tons of SO2 that would be emitted by the same units if the standard of 0.15 lb SO2/MMBtu were applied. The 0.15 lb/MMBtu standard comes from the 70 Fed. Reg. 39132 (7/6/2005) in which EPA establishes "BART limits of 95 percent SO2 removal, or an emission rate of 0.15 lb SO2/MMBtu". The MMBtu used for the analysis is an average of the actual MMBtu reported by the units to the Clean Air Markets Division for 2006, 2007 and 2008. For units that will be shutdown or operated on natural gas (Arapahoe unit 4) under the PSCo BART Alternative an emissions factor of 0.0006 lb SO2/MMBtu was used for the alternative.

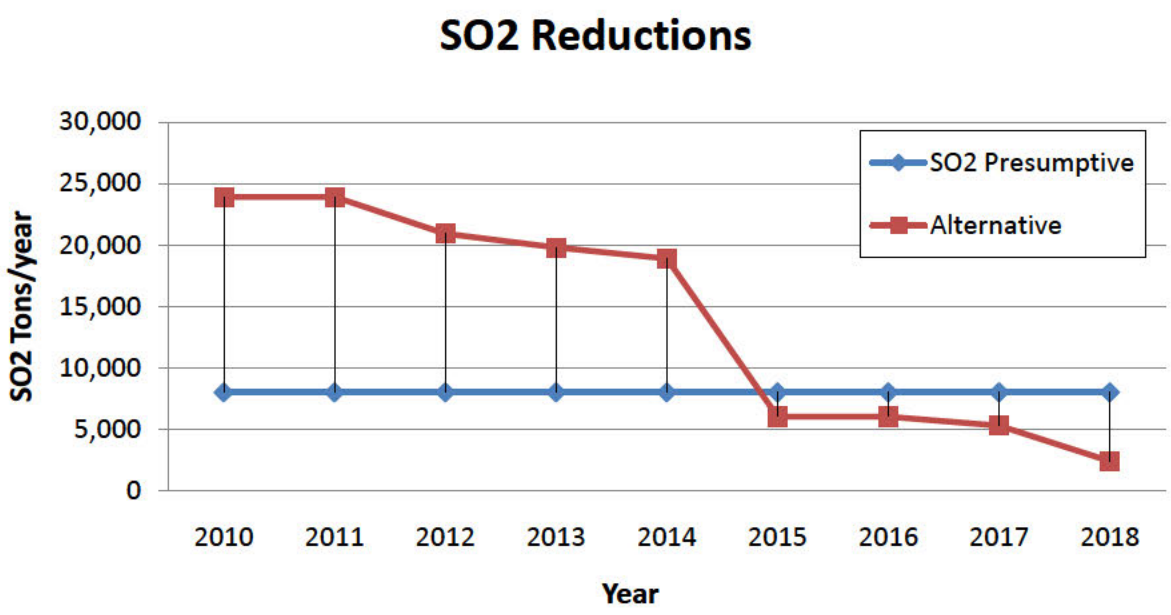
Table 6-7: SO2 Reductions Beyond Presumptive BART for PSCo Alternative

Facility	MMBtu Average 2006 to 2008	SO2 TPY Average 2006 to 2008	SO2 TPY at 0.15 lb/MMBtu Presumptive	SO2 TPY under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe					
Unit 3	4,380,121	924.97	328.51	0.00	100.00%
Unit 4	8,545,791	1,764.70	640.93	1.28[19]	99.8%
Cherokee					
Unit 1	8,311,352	2,220.80	623.35	0.00	100.00%
Unit 2	5,586,021	1,888.37	418.95	0.00	100.00%
Unit 3	8,159,889	743.00	611.99	0.00	100.00%
Unit 4	26,047,648	2,135.43	1,953.57	7.81	99.6 %
Valmont	13,722,507	758.47	1,029.19	0.00	100.00%
Pawnee	40,093,753	13,472.07	3,007.03	2,405.63	20.00%
Total	114,847,083	23,908	8,614	2,415	71.97%

The comparison with the standard of 0.15 lb SO2/MMBtu shows that the PSCo BART Alternative provides 72% lower SO2 emissions.

Figure 6-1 provides a year by year comparison of the PSCo BART Alternative to the 0.15 lb SO2/MMBtu standard for this planning period.

Figure 6-1: SO2 reductions beyond presumptive BART for PSCo Alternative



[19] Emission factor of 0.0006 lb SO2/MMBtu and 50% capacity factor.

A similar analysis was completed for NOx emissions. Table 6-8 compares the PSCo BART Alternative to a standard based on NOx limits established by EPA in 70 Fed. Reg. 39135 (7/6/2005). EPA provides a NOx lb/MMBtu level based on the boiler type and the coal type burned. The PSCo BART Alternative reflects 600 tpy of NOx emitted from Arapahoe 4 operating on natural gas as a "peaking" unit, 300 tpy of NOx reserved for "netting" or "offsets" from the Arapahoe facility, and 500 tpy of NOx reserved for "netting" or "offsets" from the Cherokee facility.

Table 6-8: NOx Reductions Beyond Presumptive BART for PSCo Alternative

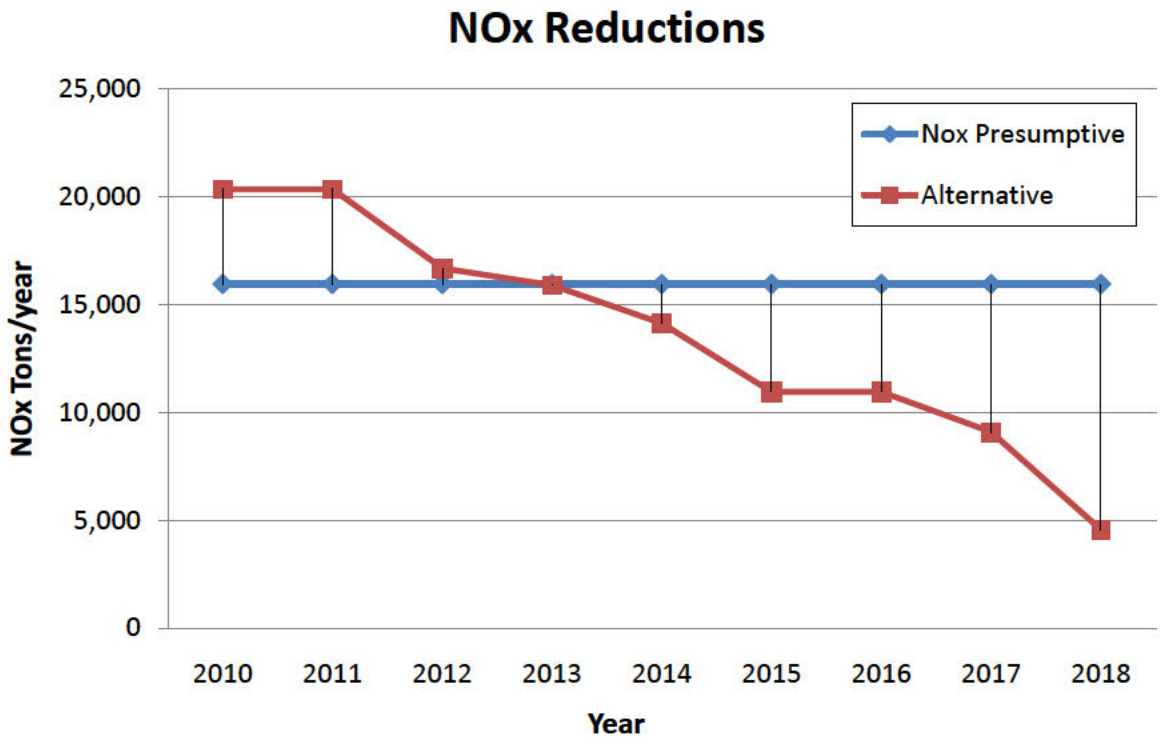
Facility	MMBtu Average 2006 to 2008	NOx TPY Average 2006 to 2008	NOx lb/MMBtu Standard	TPY NOx at Standard	TPY NOx Under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe						
Unit 3	4,380,121	1,770.47	0.23	503.71	0.00	100.00%
Unit 4	8,545,791	1,147.67	0.23	982.77	900.00[20]	8.42%
Cherokee						
Unit 1	8,311,352	1,556.23	0.39	1,620.71	0.00	100.00%
Unit 2	5,586,021	2,895.20	0.39	1,089.27	0.00	100.00%
Unit 3	8,159,889	1,865.50	0.39	1,591.18	0.00	100.00%
Unit 4	26,047,648	4,274.00	0.28	3,646.67	2,062.86[21]	43.43%
Valmont	13,722,507	2,313.73	0.28	1,921.15	0.00	100.00%
Pawnee	40,093,753	4,537.73	0.23	4,610.78	1,403.28	69.57%
Total	114,847,083	20,361		15,966	4,366	72.65%

Figure 6-2 illustrates the year by year reductions achieved by the PSCo BART Alternative as compared to the standard derived from the EPA standard based on the configuration of each unit and the coal type burned by the unit in the PSCo BART Alternative.

[20] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a "peaking" unit and 300 tpy NOx reserved for "netting" and "offsets" for additional natural gas generation. The 300 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with either unit.

[21] Cherokee 4 operating on natural gas at 0.12 lb NOx/mmBTU and 500tpy NOx reserved for "netting" or "offsets". The 500 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with any combination of the units.

Figure 6-2: NOx Reductions Beyond Presumptive BART for PSCo Alternative



The PSCo BART Alternative provides a reduction of 15,994 tons per year of NOx and 21,493 tons per year of SO2 from the baseline (average of 2006-2008 actuals) (89% and 77% reduction, respectively). These SO2 and NOx reductions provide significantly greater reductions as compared to the application of the standard set forth in 70 Fed. Reg. 39132-39135 (7/6/2005) applied all the units in the PSCo BART Alternative. The PSCo BART Alternative provides a 71% improvement in NOx reductions (See Table 6-8) over the presumptive levels, and a 72% improvement in SO2 reductions (See Table 6-7) over the presumptive levels. This is a significantly higher reduction than would have been achieved through the application of the presumptive limits. The state's alternative program is thus "clearly superior" to source-specific BART. *See* 71 Fed. Reg. at 60615. It provides not only for further emission reductions at units, but reflects the closure of numerous units, and thus the complete elimination of emissions from those units. Because these measures will provide greater emission reductions and will occur within the first planning period, the state has determined that they also satisfy reasonable progress for these sources. In this regard, Colorado has reasonably concluded that any control requirements imposed in the BART context also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," p. 4-2 (June 2007).

Supplemental Technical Analysis Supporting the Alternative measure demonstration for the PSCo Alternative

In addition to the foregoing demonstration that the PSCo BART Alternative satisfies the requirements of 40 CFR 51.308(e)(2) for an approvable alternative to EPA"s BART regulation, the state undertook and provides the following additional technical analyses to support its determination that the PSCo BART Alternative demonstrates greater reasonable progress than the installation of BART on subject to BART units.

Colorado also evaluated the NOx reductions of the alternative program based on the criteria established by the state for BART and reasonable progress for NOx reductions. As part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state"s calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state"s calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

For the PSCo BART Alternative sources included in the PSCo BART Alternative, SCR costs (where technically feasible) are greater than $5,000 per ton of NOx removed or the visibility improvement from SCR is less than 0.50 Δdv. See analysis in appendix C. Under the state"s criteria this would eliminate SCR from further consideration as a control alternative for BART and reasonable progress. Thus, for demonstration purposes the state has compared the PSCo BART Alternative with the emission reductions achievable by SNCR. The division used study of SNCR on coal fired boilers in the size range of those in the PSCO BART Alternative. The study showed that the SNCR tested achieved a 35% reduction in NOx with less than 2ppm NH3 slip and 54% reduction with a 10ppm NH4 slip.[22] Because of the high ammonia slip at the higher range of NOx removal the division determined that 50% removal was appropriate for this comparison. Thus, for comparative purposes for the PSCo BART Alternative, the state will assume that SNCR is applied at a level of NOx reduction, of 50%, to assess performance of presumed SNCR on these units as against the PSCo BART Alternative for NOx.[23] Table 6-9 provides a comparison of the costs for SCR and SNCR as provided by PSCo, SNCR at a 50% reduction (calculated from an average of NOx actual from 2006-2008 as reported to the Clean Air Markets Division) and the PSCo BART Alternative.

[22] Environmental Controls Conference, Pittsburgh, PA (5/16/2006 to 5/18/2006)

[23] This level of NOx control efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that SNCR on these particular electric generating units could, in fact, achieve this level of NOx reduction performance from application of SNCR.

Table 6-9: NOx reductions beyond state criteria for PSCo Alternative

Facility	SCR $/ton	SNCR $/ton	SNCR TPY at 50%[24]	PSCo Alternative TPY	% Reduction from SNCR at 50% Control
Arapahoe					
Unit 3			885.23	0	100.00%
Unit 4			573.83	900[25]	-56.84%
Cherokee					
Unit 1	N/A	$8,737	778.12	0	100.00%
Unit 2	N/A	$3,963	1,447.60	0	100.00%
Unit 3	$10,134	$3,485	932.75	0	100.00%
Unit 4	$6,252	$2,625	2,137.00	2,062[26]	3.47%
Valmont	$8,647	$3,328	1,156.87	0	100.00%
Pawnee	$4,371	$3,082	2,268.87	1,403	38.15%
Total			10,180	4,366	57.11%

The PSCo BART Alternative results in 55% more reduction in NOx than the assumed installation of SNCR at all units covered by the PSCo BART Alternative. A similar analysis was not completed for SO2 because the state did not look at SO2 controls for reasonable progress as all sources were already controlled.

For both SO2 and NOx the state also evaluated the PSCo BART Alternative against a source by source analysis. For SO2 the state has done source specific analyses for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 95% control level assumption to the uncontrolled emissions from those sources. The 95% was taken both from current operations and from uncontrolled emissions calculated using AP-42.[27] The analysis demonstrates that the alternative proposed is better than the source by source analysis by more than 52% as shown in Table 6-10. Figure 6-3 shows the reductions

[24] Fifty percent reduction was taken from an average of 2006-2008 actual NOx emissions as reported to the Clean Air Markets Division.

[25] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a “peaking” unit and 300 tpy NOx reserved for “netting” and “offsets” for additional natural gas generation.

[26] Cherokee 4 operating on natural gas at 0.12 lb NOx/MMBtu and 500 tpy NOx reserved for “netting” or “offsets”.

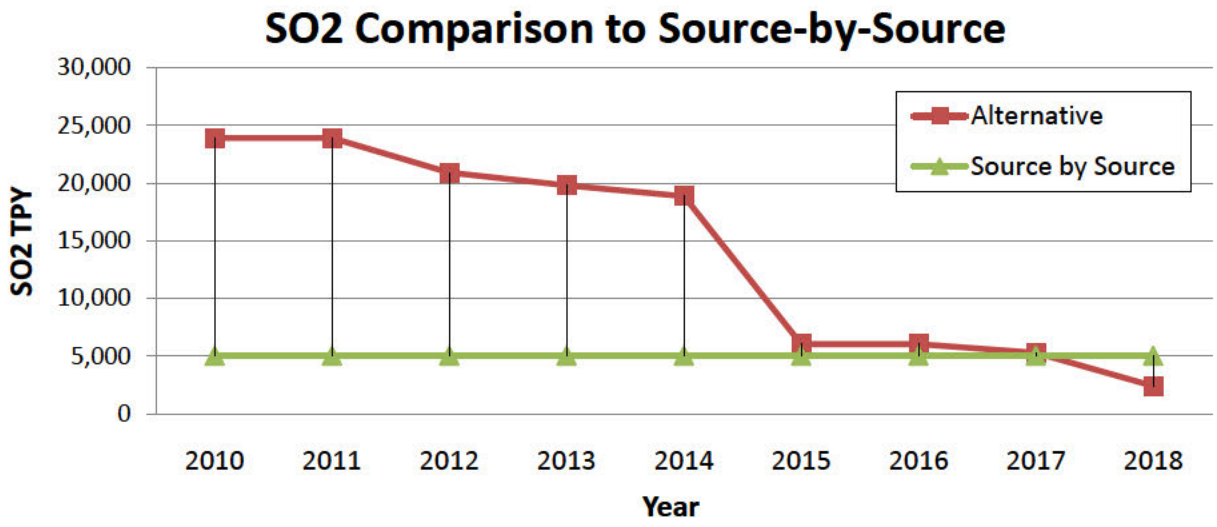
[27] This level of SO2 reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units burning low-sulfur western coal, could, in fact, achieve this level of SO2 reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities. This is different from the other analyses provided in this document, and when employing a 95% reduction assumption for demonstration purposes for an alternative measure makes the starting point for the sources in the Alternative more similar to uncontrolled eastern sources, where a higher sulfur content coal is generally utilized, which is more relevant to an assumed 95% reduction of SO2.

from the PSCo BART Alternative as compared to the source by source evaluation on a year to year basis.

Table 6-10: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative

Facility	SO2 TPY from AP-42	Source-by-Source	SO2 TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	1,076.53	53.82	0.00	100.00%
Unit 4	2,322.21	1.28	1.28	0.00%
Cherokee				
Unit 1	2,803.67	140.18	0.00	100.00%
Unit 2	2,662.17	133.10	0.00	100.00%
Unit 3	3,438.79	171.93	0.00	100.00%
Unit 4	9,779.27	1,953.57[28]	7.81	99.6%
Valmont	3,822.73	191.13	0.00	100.00%
Pawnee	8,342.36	2,405.62[29]	2,405.63	0.00%
Total	34,248	5,051	2,415	52.19%

Figure 6-3: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative



[28] The Cherokee Unit 4 BART evaluation concluded that a 0.15 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

[29] The Pawnee BART evaluation concluded that a 0.12 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

For NOx the state looked at a source by source analysis for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 90% control level assumption to the sources. The 90% was taken from emissions calculated using AP-42.[30] The source by source analysis considered the operation of Arapahoe Unit 4 with natural gas as a peaking unit and retaining 300 tpy of NOx for future netting or offsets from Arapahoe, the operation of Cherokee Unit 4 on natural gas at 0.12 lb/MMBTU and retaining 500 tpy of NOx from Cherokee for future netting, and control of Pawnee with SCR at 0.07 lb/MMBTU. The results of the comparison indicate that the alternative proposed is 49% better than the source by source analysis.

Table 6-11: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative

Facility	NOx TPY from AP-42	Source-by-Source	NOx TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	2,149.15	214.91	0.00	100.00%
Unit 4	4,636.00	600	900.00[31]	-50.00%
Cherokee				
Unit 1	3,596.54	359.65	0.00	100.00%
Unit 2	3,415.03	341.50	0.00	100.00%
Unit 3	4,411.28	441.12	0.00	100.00%
Unit 4	7,878.04	2,735.00[32]	2,062.86[33]	24.58%
Valmont	2,061.04	206.10	0.00	100.00%
Pawnee	7,945.11	3,608.43	1,403.28	61.11%
Total	36,092	8,507	4,366	48.67%

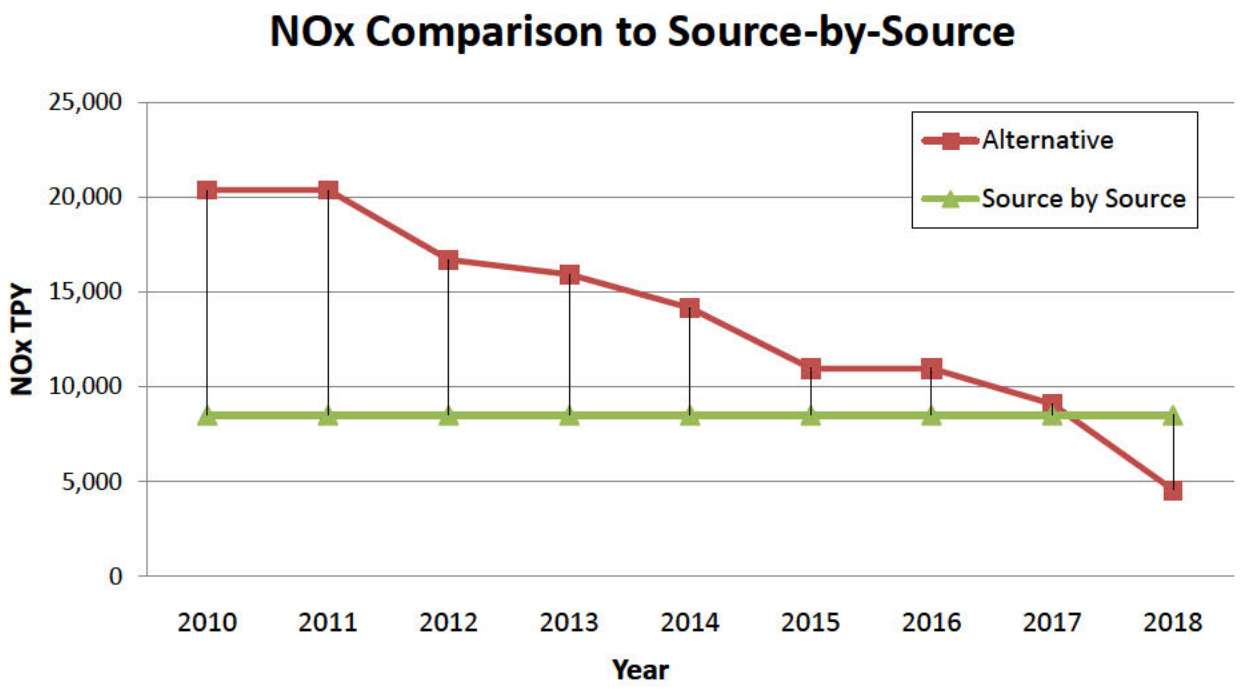
[30] This level of NOx reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units, could, in fact, achieve this level of NOx reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities.

[31] Natural gas operation as a peaking unit limited to 600 tpy with 300 tpy NOx reserved for offsets or netting for additional natural gas generation.

[32] Coal fired operation with SNCR at 0.21 lb NOx/MMBtu.

[33] Natural gas operation at 0.12 lb NOx/MMBtu with 500 tpy NOx reserved for offsets or netting.

Figure 6-4: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative



Conclusion

Under EPA regional haze regulations, Colorado has utilized an emission based comparison to demonstrate that that the PSCo BART Alternative provides greater reasonable progress than, and is clearly superior to, source by source BART. Although not necessary, as a means of further supporting its demonstration, the state has utilized other methodologies to demonstrate that the PSCo BART Alternative achieves greater reasonable progress than BART or individual reasonable progress requirements. The PSCo BART Alternative will result in early and significant reductions of visibility impairing pollutants.

Table 6-12: PSCo Alternative Emissions Limits[34, 35, 36]

Unit	NOx Control Type	NOx Emission Limit	SO2 Control Type	SO2 Emission Limit	Particulate Type And Limit
Cherokee Unit 1	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012	0	Shutdown No later than 7/1/2012
Cherokee Unit 2	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011
Cherokee Unit 3	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016	0	Shutdown No later than 12/31/2016
Cherokee Unit 4	Natural Gas Operation	0.12 lb/MMBtu (30-day rolling average) by 12/31/2017	Natural Gas Operation 12/31/2017	7.81 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5	Shutdown 12/31/2017	0	Shutdown 12/31/2017	0	Shutdown 12/31/2017
Pawnee Unit 1	SCR**	0.07 lb/MMBtu (30-day rolling average) by 12/31/2014	Lime Spray Dryer**	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	Fabric Filter Baghouse* 0.03 lbs/MMBtu
Arapahoe Unit 3	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Arapahoe Unit 4	Natural Gas Operation	600 tpy (12 month rolling average) by 12/31/2014	Natural Gas operation 12/31/2014	1.28 tpy (12 month rolling average)	Fabric Filter Baghouse* 0.03 lbs/MMBtu Natural Gas operation 12/31/2014

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

[34] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.

[35] 500 tpy NOx will be reserved from Cherokee Station for netting or offsets.

[36] 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation.

Chapter 7 Visibility Modeling and Apportionment

Modeling results and technical analyses indicate that Colorado sources contribute to visibility degradation at Class I areas. The modeling also shows out-of-state sources have the greatest impact on regional haze in Colorado. As such, this Plan anticipates local and regional solutions so that Colorado"s 12 Class I areas make progress towards the 2018 and 2064 visibility goals.

7.1 Overview of the Community Multi-Scale Air Quality (CMAQ) Model

The Regional Modeling Center (RMC) Air Quality Modeling group is responsible the Regional Haze modeling for the WRAP. The RMC is located at the University of California - Riverside in the College of Engineering Center for Environmental Research and Technology.

The RMC modeling analysis is based on a model domain comprising the continental United States using the Community Multi-Scale Air Quality (CMAQ) model. The EPA developed the CMAQ modeling system in the late 1990s. CMAQ was designed as a "one atmosphere" modeling system to encompass modeling of multiple pollutants and issues, including ozone, PM, visibility, and air toxics. This is in contrast to many earlier air quality models that focused on single-pollutant issues (e.g., ozone modeling by the Urban Airshed Model). CMAQ is an Eulerian model - that is, it is a grid-based model in which the frame of reference is a fixed, three-dimensional (3-D) grid with uniformly sized horizontal grid cells and variable vertical layer thicknesses. The key science processes included in CMAQ are emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species.

A detailed summary of the CMAQ modeling for each Class I area is included in Section 6 of the Technical Support Document.

7.2 CMAQ Modeling Results for 2018

Figure 7-1 lists the 2018 Uniform Progress (UP) for each class I area along with the visibility modeling forecasts for 2018. These modeling results were released in 2006 by the WRAP and are preliminary; new modeling results with the latest emission estimates and control measure benefits are anticipated mid- to late 2007, and additional modeling is scheduled to be performed in 2008 and 2009. The results of this modeling will be utilized in defining (RPGs) for all 12 Colorado Class I areas by the year 2010 as described in Chapter 9.

As indicated by the 2006 modeling, reasonable progress for each Class I area falls short of meeting 2018 uniform progress for the 20% worst days, as indicated by the numbers in the blue highlighted box. Alternatively, all areas are forecast to maintain the best days in 2018.

More detailed information on the CMAQ modeling for a particular Class I area can be found in Section 6 of the Technical Support Document.

Figure 7-1 Summary of CMAQ Modeling Progress Towards 2018 UP

Colorado Mandatory Class I Federal Areas
Uniform Progress Summary in Haze Index Metric
Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days					20% Best Days		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

7.3 Overview of Particulate Matter Source Apportionment Technology (PSAT) Modeling

The Regional Modeling Center (RMC) at the University of California – Riverside developed the PSAT algorithm in the Comprehensive Air quality Model with extensions (CAMx) model to assess source attribution. The PSAT analysis is used to attribute particle species, particularly sulfate and nitrate from a specific location within the Western Regional Air Partnership (WRAP) modeling domain. The PSAT algorithm applies nitrate-sulfate-ammonia chemistry to a system of tracers or “tags” to track the chemical transformations, transport and removal of emissions.

Each state or region (i.e. Mexico, Canada) is assigned a unique number that is used to tag the emissions from each 36-kilometer grid cell within the WRAP modeling domain. Due to time and computational limitations, only point, mobile, area and fire emissions were tagged.

The PSAT algorithm was also used, in a limited application (e.g. no state or regional attribution) due to resource constraints, to track natural and anthropogenic species of organic aerosols at each CIA. The organic aerosol tracer tracked both primary and secondary organic aerosols (POA & SOA). Appendix H includes more information on PSAT methodology.

More detailed information on the PSAT modeling can be found in Section 7 of the Technical Support Document for each Class I area.

7.4 PSAT Modeling Results for 2018

Figure 7-2 provides the four highest source areas contributing sulfate and nitrate at each Class I area. As indicated, boundary conditions (BC) are the highest contributor to sulfate at all Colorado Class I areas. The boundary conditions represent the background concentrations of pollutants that enter the edge of the modeling domain. Depending on meteorology and the type of pollutant (particularly sulfate), these emissions can be transported great distances that can include regions such as Canada, Mexico, and the Pacific Ocean. Colorado appears to be a major contributor of particulate sulfate at those Class I areas near significant sources of SO2.

For nitrate, Colorado appears to be a major contributor at most of our Class I areas except for the Weminuche Wilderness, La Garita Wilderness and Black Canyon of Gunnison National Park. Although, boundary conditions also appear to be a major contributor of nitrate at all our Class I areas.

Figure 7-2 Summary of PSAT Modeling for 2018

WRAP - PM Source Apportionment Technology (PSAT) Modeling Results

Results based on 2018b Modeling

Class I Area	2018 Sulfate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area					2018 Nitrate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area				
	Sources*	1st	2nd	3rd	4th	Sources*	1st	2nd	3rd	4th
Great Sand Dunes National Park & Preserve		OD 38.2%	CO 9.7%	NM 8.1%	MEX 7.9%		OD 28.9%	NM 27.2%	CO 12.3%	CEN 8.8%
Mesa Verde National Park		OD 35.4%	NM 17.2%	MEX 11.3%	AZ 10.2%		NM 60.2%	CO 12.3%	OD 9.7%	AZ 9.7%
Mount Zirkel & Rawah Wilderness Areas		OD 29.3%	CO 20.9%	WY 9.2%	UT 7.6%		CO 41.6%	OD 17.8%	UT 14.1%	WY 10.3%
Rocky Mountain National Park		OD 29.1%	CO 23.5%	WY 7.7%	CEN 7.2%		CO 33.7%	OD 15.8%	WY 11.0%	UT 5.9%
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas		OD 34.9%	NM 13.2%	MEX 10.7%	PO 9.1%		NM 43.7%	OD 19.7%	CA 14.1%	AZ 9.9%
Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas		OD 40.1%	MEX 10.8%	AZ 6.8%	NM 6.1%		OD 55.0%	UT 20.0%	CO 15.0%	NM 10.0%

Notes:
'OD' denotes Outside Domain
'CEN' denotes the Central Regional Air Partnership (CENRAP)
'MEX' denotes the country of Mexico
'PO' denotes the Pacific Offshore

** Boundary Conditions not included in Pie Charts*

Point Sources
Area Sources
Mobile Sources
Natural Fire

Point Sources
Area Sources
Mobile Sources
Natural Fire

Figure 7-3 identifies the change in the Colorado portion of particulate sulfate and nitrate concentrations, from 2002 to 2018 at each Class I area. For 2018, the PSAT modeling forecasts a reduction in the Colorado portion of sulfate at all Class I areas ranging from 25% to 33%. These particulate sulfate reductions are due to reductions from point and mobile source sulfur dioxide emissions (see Figure 5-1).

The 2018 forecasts for nitrate appear mixed with increases of 25% to 27% at the southwest Colorado Class I areas and nitrate reductions of 9% to 28% at all other areas. The increase in particulate nitrate in southwest Colorado is likely due to forecast increases in Colorado"s and the region"s NOx emissions from area sources and oil & gas development (see Figure 5-2). The projected particulate nitrate reductions at the remaining Class I areas are due to NOx reductions in mobile sources.

Figure 7-3 Colorado Share of Modeled Sulfate and Nitrate Changes for 2018

Change in Modeled Concentration for Colorado Share

Based PM Source Apportionment Technology (PSAT) Modeling Results (2018b)

Class I Area	Year	Total SO4 [ug/m3]	Colorado SO4 [ug/m3]	Colorado Share SO4	Colorado Sulfate Change	Total NO3 [ug/m3]	Colorado NO3 [ug/m3]	Colorado Share NO3	Colorado Nitrate Change
Great Sand Dunes National Park & Preserve	2002	0.440	0.057	13%		0.116	0.017	15%	
	2018	0.442	0.043	10%	-25%	0.114	0.014	12%	-18%
Mesa Verde National Park	2002	0.665	0.013	2%		0.249	0.026	10%	
	2018	0.644	0.009	1%	-31%	0.269	0.033	12%	+27%
Mount Zirkel & Rawah Wilderness Areas	2002	0.649	0.175	27%		0.214	0.085	40%	
	2018	0.621	0.130	21%	-26%	0.185	0.077	42%	-9%
Rocky Mountain National Park	2002	0.760	0.238	31%		0.339	0.128	38%	
	2018	0.677	0.159	23%	-33%	0.273	0.092	34%	-28%
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	2002	0.484	0.024	5%		0.080	0.004	5%	
	2018	0.484	0.018	4%	-25%	0.071	0.005	7%	+25%
Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas	2002	0.428	0.028	7%		0.020	0.004	20%	
	2018	0.424	0.021	5%	-25%	0.020	0.003	15%	-25%

Chapter 8 Reasonable Progress

8.1 Overview of Reasonable Progress Requirements

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals (expressed in deciviews) for each Class I area in Colorado that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. These reasonable progress goals (RPGs) are to provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

In establishing the RPGs, the state must consider four factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. As well, the state must include a demonstration showing how these factors were taken into consideration in selecting the goals.

In establishing RPGs, the state must estimate the 2018 uniform rate of progress (URP) for each Class I area. The state must consider the URP and the emission reductions needed to achieve URP for the period covered by the plan. If the state ultimately establishes a Reasonable Progress Goal that provides for a slower rate of visibility improvement than would be necessary to meet natural conditions by 2064, the state must demonstrate that the uniform rate is not reasonable and that the state"s alternative goal is reasonable, based on an evaluation of the 4 factors. In addition, the state must provide to the public an assessment of the number of years it would take to achieve natural conditions if improvement continues at the rate selected by the state. The detailed discussion of Reasonable Progress Goals can be found in Chapter 9, “Long Term Strategy”. The establishment of the pollutants for RP evaluations and the evaluation of significant sources for reasonable progress is presented below.

8.2 Visibility Impairing Pollutants Subject to Evaluation

The state conducted a detailed evaluation[37] of the six particulate pollutants; ammonium sulfate, ammonium nitrate, organic carbon (OC), elemental carbon (EC), fine soil and coarse mass (CM) (both of which are commonly known as particulate matter (PM)), contributing to visibility impairment at Colorado"s 12 mandatory Class I federal areas, and determined that the first Regional Haze Plan RP evaluation should focus on significant point sources of SO2 (sulfate precursor), NOx (nitrate precursor) and PM emissions. Emission sources are best understood for these three visibility-impairing pollutants, and stationary, or “point” sources, dominate the emission inventories and apportionment modeling. This determination is based on the well documented point source emission inventories for SO2 and NOx, and the Regional Model performance for sulfate and nitrate was determined to be acceptable. Significant point source PM emissions are also evaluated because of the Q/d screening methodology (Q = total

[37] *Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas*, October 2, 2007. See the Technical support Document

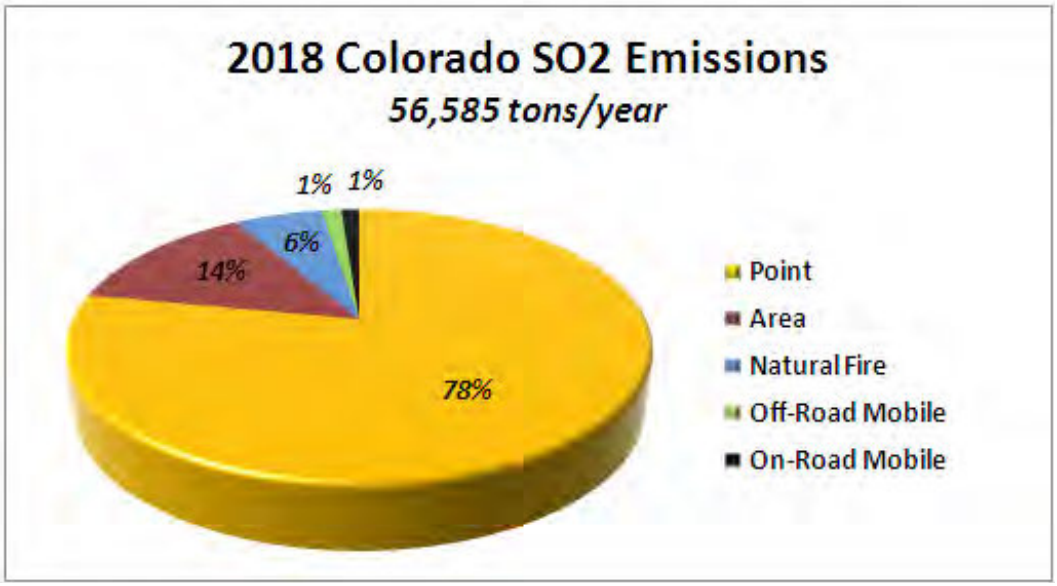
SO2, NOx and PM emissions; d = distance from the nearest Class I area, as further described in section 8.3), which includes PM emissions. PM emissions from other anthropogenic and natural sources are not being evaluated at this time.

Mobile and area sources were also identified as significant contributors to nitrates, and the RP evaluation of these two source categories is presented in section 8.2 above.

Generally, the sources of other visibility impairing pollutants, OC, EC, and PM, are not well documented because of emission inventory limitations associated with natural sources (predominantly wildfires), uncertainty of fugitive (windblown) emissions, and poor model performance for these constituents. Without a sound basis for making emission control determinations for sources that emit these three pollutants, Colorado determines that it is not reasonable in this planning period to recommend emission control measures; the State intends to address these pollutants and their emissions sources in future plan updates.

Figure 8-1 provides the statewide projected 2018 SO2 emissions, which reflects "on-the-books (OTB)" and "on-the-way (OTW)" emission control measures as of January 2009 (the latest year for a complete emissions inventory compiled by the Western Regional Air Partnership (WRAP)).

Figure 8-1: Relative Source Contributions to Colorado SO2 Emissions in 2018

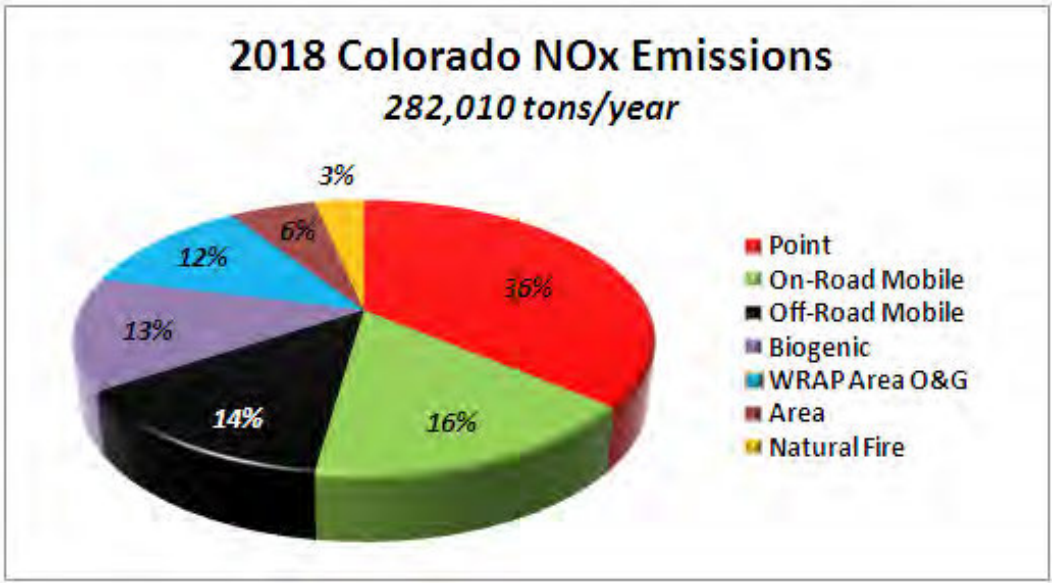


As indicated, 78% of total statewide SO2 emissions are from point sources – largely coal-fired boilers. Area source SO2 emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content of distillate fuel ranges between 500 ppm to 5000 ppm. SO2 emissions from natural fires are considered uncontrollable and vary from year-to-year depending on precipitation, fuel loading and lightning. Both off-road and on-road mobile sources are subject to federal ultra-low sulfur diesel (ULSD) fuel requirements that limit sulfur content to 15 ppm (0.0015 %) that was in widespread use after June 2010 for off-road mobile and June 2006 for on-road mobile.

The state has determined that point sources are the dominant source of emissions and, for this planning period, the only practical category to evaluate under reasonable progress for SO2.

Figure 8-2 provides the statewide projected 2018 NOx emissions, which reflects OTB and OTW emission control measures as of October 2009 (the latest year for a complete emissions inventory compiled by the WRAP).

Figure 8-2: Relative Source Contributions to Colorado NOx Emissions in 2018



Point sources comprise 36% of total NOx emissions that are mostly coal-fired external combustion boilers and natural gas-fired internal combustion engines (in oil and gas compression service). On-road and off-road mobile sources comprise 16% and 14% of statewide NOx emissions respectively. A portion of the on-road mobile source NOx emissions reflect some level of NOx control because of the Denver metro-area vehicle inspection program (IM-240). Both on/off road mobile also benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. Because mobile exhaust emissions are primarily addressed, and will continue to be addressed, through federal programs, mobile sources will not be evaluated by Colorado for further RP control in this planning period. NOx emissions from biogenic activity and natural fire are considered uncontrollable and vary from year-to-year. Non-oil and gas area sources comprise about 6% of NOx emissions that involve thousands of combustion sources that are not practical to evaluate in this planning period.

The state has determined that large point sources are the dominant source of emissions and for this planning period are practical to evaluate under reasonable progress for NOx. Also, certain smaller point sources and area sources of NOx will also be evaluated under RP.

8.3 Evaluation of Smaller Point and Area Sources of NOx for Reasonable Progress

Oil and gas area source NOx emissions have been determined to significantly contribute to visibility impairment in Colorado"s Class I areas. Because this source category is made up of numerous smaller sources, it is only practical to evaluate the category for RP control as a whole, unlike point sources where individual sources are evaluated separately. When reviewing O&G area sources, natural gas-fired heaters, and reciprocating internal combustion engines (RICE), are identified as the largest NOx emission sources. When reviewing point sources, natural gas-fired turbines were also identified as significant for review for RP.

8.3.1 Oil and Gas Heater Treaters

A heater-treater is a device used to remove contaminants from the natural gas at or near the well head before the gas is sent down the production line to a natural gas processing plant. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead.

The latest 2018 emissions inventory for the state assumes approximately 23,000 tons of NOx per year from 26,000 natural gas heater-treaters in Colorado at an emissions level of 0.88 tpy NOx per gas well heater-treater.

Emissions control research and control application for this source category is not well developed and has focused primarily on methane reductions. Though there are some technically feasible control options, the costs of compliance and the control effectiveness cannot be confidently determined. While the cumulative emissions make this a significant source category, the state determines that, for this planning period, requiring the control of 26,000 individual sources less than one ton per year in size is not practical or reasonable for reasonable progress.

A detailed 4-factor analysis for heater treaters can be found in Appendix D.

8.3.2 Reciprocating Internal Combustion Engines

Power generated by large reciprocating internal combustion engines (RICE) is generally used to compress natural gas or to generate electricity in remote locations. The designation “large” refers to RICE that have an engine rating of at least 100 horsepower (hp) for the purpose of this reasonable progress analysis.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios. If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. RICE are operated with either fuel-rich ratios at or near stoichiometric, which are called rich-burn engines (RB), or air-rich ratios below stoichiometric, which are called lean-burn engines (LB). Undesirable emissions from RICE are primarily nitrogen oxides (NO_x; primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). NO_x are formed by thermal oxidation of nitrogen from the air. CO and VOCs are formed from incomplete combustion. Rich-burn engines inherently have higher NOx emissions by design, and lean burn engines are designed to have relatively lower NOx emissions.

Colorado has undertaken regulatory initiatives to control NOx emissions from RICE, beginning in 2004. For the Denver metro area/North Front Range ozone control area, Regulation No. 7 was revised to require the installation of controls on new and existing rich burn and lean burn RICE larger than 500 hp by May 1, 2005. Controls for rich burn RICE are non-selective catalytic reduction (NSCR) and an air-to-fuel ratio controller, which effectively controls NOx (95%), CO and VOCs. Controls for lean burn RICE are oxidation catalyst reduction, which effectively control CO and VOCs. An exemption from control for lean burn RICE could be obtained upon demonstration that cost of emission control would exceed $5,000 per ton. Selective catalytic reduction was considered for the control of NOx from lean burn engines, but was dismissed due to the high cost/effectiveness at approximately $22,000/ton (see Appendix D for complete analysis). EPA approved this requirement as part of the Colorado SIP on August 19, 2005 (70 Fed. Reg. 48652 (8/19/05)).

In December 2008, Colorado proceeded to adopt into Regulation No. 7 similar provisions for all existing RICE over 500 hp throughout the state. By July 1, 2010 all existing engines in Colorado, had to install controls as described in the paragraph above, with the one exception that the $5,000 per ton exemption applied to both lean burn and rich burn engines. The state-only provision for rich-burn RICE (which reduces NOx emissions and is codified in Regulation No. 7, Sections XVII.E.3. and 3.a.) is being included as part of the Regional Haze SIP to become federally enforceable upon EPA approval.

For RICE NOx control under the Regional Haze rule, Colorado determines that the installation of NSCR on all rich burn RICE throughout the state satisfies RP requirements. The accompanying benefits of reducing VOCs and CO also support this RP determination. Additional NOx control for lean burn RICE throughout the state is not reasonable for this planning period.

For new and modified RICE of 100 hp or greater, the state is relying on emissions controls that are required by EPA's New Source Performance Standards (NSPS) Subpart JJJJ, 40 CFR Part 60 and EPA's National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ, 40 CFR Part 63. Colorado determines that this federal control program satisfies reasonable progress for these sources in this planning period.

For existing RICE less than 500 hp throughout the state, the state determines that no additional control is necessary for RP in this planning period. Colorado"s emission inventory system indicates that in the 2007/2008 timeframe, there were 538 engines less than 500 hp in the state, and these engines emitted 5,464 tons/year of NOx. At an average of about 10 tons of NOx emissions per year, controlling engines of this size is not reasonable. Many of these smaller existing engines will eventually be brought into JJJJ and ZZZZ when modified in the future, so it is reasonable to assume that additional NOx reductions will occur.

The 2018 emissions inventory assumes approximately 16,199 tons of NOx per year from RICE of all sizes in Colorado. The NOx control achieved by controlling rich burn engines in the ozone control area (approximately 7,000 tons/year) is assumed in this number. Controlling the remaining rich burn engines statewide reduces the 2018 RICE

NOx emissions inventory by approximately 5,800 tons/year to approximately 10,400 tons/year. For new RICE subject to the NSPS and NESHAP, NOx emissions reductions have not been estimated. Because the 2018 estimate of 16,199 tons/year of NOx assumed growth in uncontrolled engines and did not account for th NSPS and NESHAP, the 10,400 ton/year emissions in 2018 should be even lower. The remaining NOx from engines is attributed to existing lean burn engines which are uncontrolled for NOx (though they will eventually be brought into JJJJ and ZZZZ when modified in the future), existing rich burn engines after control, small engines, and new RICE after the application of JJJJ and ZZZZ.

A detailed 4-factor analysis for RICE can be found in Appendix D.

8.3.3 Combustion Turbines

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the state‟s air emissions inventory. Typical emissions for this source type may be significant for NOx, but pipeline quality natural gas is inherently clean and low-emitting for SO2 and PM10 emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

RP evaluations are triggered for turbines that are co-located at BART or RP sources that have been determined to be significant because they have a Q/d impact of greater than 20 (see section 8.3 below for a description of this “significance” determination). The state analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period. There are five Reasonable Progress facilities with combustion turbines – PSCo Valmont Generating Station, PSCo Arapahoe Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two turbines located at the Nixon Plant emit significant levels of visibility impairing emissions, as defined by the federal Prevention of Significant Deterioration (PSD) significance levels:

- NO_x – 40 tons per year
- SO_2 – 40 tons per year
- PM_{10} – 15 tons per year

Facility – Turbine	Total 2006 – 2008 Averaged NOx Annual Emissions (tpy)	Total 2006 – 2008 Averaged SO2 Annual Emissions (tpy)	Total 2006 – 2008 Averaged PM10 Annual Emissions (tpy)	Greater than *de minimis* levels?
Front Range Power Plant – Turbine #1	159.6	2.9	4.9	Yes – NOx only
Front Range Power Plant – Turbine #2	147.9	2.8	4.9	Yes – NOx only

The combustion turbines at the Front Range Power Plant were installed with advanced dry-low NOx combustion systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NOx reductions, respectively.

There is one feasible emission control technology available for these turbines is adding post combustion technology – selective catalytic reduction (SCR) which, in good working order can achieve removal efficiencies ranging from 65 – 90 percent from uncontrolled levels.

Applying SCR would achieve up to an additional 90% control efficiency to both turbines and could result in about 275 tons of NOx reduced annually with a capital expenditure of at least $15 million. The state estimates that SCR for these turbines will range from approximately $57,000 - $62,000 per ton of NOx reduced annually. In the state"s judgment for this planning period for Reasonable Progress, the potential 275 tons per year of NOx reductions are not cost-effective. The state has determined that NOx RP for combustion turbines is existing controls and emission limits.

A detailed 4-factor analysis for combustion turbines can be found in Appendix D.

8.4 Determination of Point Sources Subject to Reasonable Progress Evaluation

Colorado refined the RP analysis referred to in Section 8.2 (using the latest WRAP emission inventory data) to select specific point sources to evaluate for RP control[38]. This RP screening methodology involves a calculated ratio called "Q-over-d", that evaluates stationary source emissions (mathematical sum of actual SO2, NOx and PM emissions in tons per year, denoted as "Q") divided by the distance (in kilometers, denoted as "d") of the point source from the nearest Class I area.

The State evaluated the visibility impact sensitivity of different Q/d thresholds and determined that a Q/d ratio equal to or greater than "20" approximated a delta deciview (Δdv) impact ranging from 0.06 Δdv to 0.56 Δdv. The resultant average of the range is about 0.3 Δdv, which is a more conservative RP threshold than the 0.5 Δdv that was used in determining which sources would be subject-to-BART under the federal BART regulations. The delta deciview impact was determined by evaluating CALPUFF

[38] *Reasonable Progress Analysis of Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas,* March 31, 2010. See the Technical Support Document

modeling, conducted by the state in 2005, for the ten subject-to-BART stationary sources. Since the Q/d methodology involves consideration of PM emissions, the state has added PM (PM-10) emissions to the RP evaluation process.

The evaluation of potential RP sources involved all Colorado stationary sources with actual SO2, NOx or PM10 emissions over 100 tons per year based on Air Pollution Emissions Notice (APEN) reports from 2007. The one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants (see Figure 8-3) were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I area boundary. The Q/d was calculated for each source, and Table 8-1 lists the sixteen (16) point sources that are equal to or greater than the Q/d of 20 threshold. These sixteen sources will be referred to as "significant" sources for purposes of reasonable progress.

Figure 8-3: Point Sources with >100 TPY of Emissions

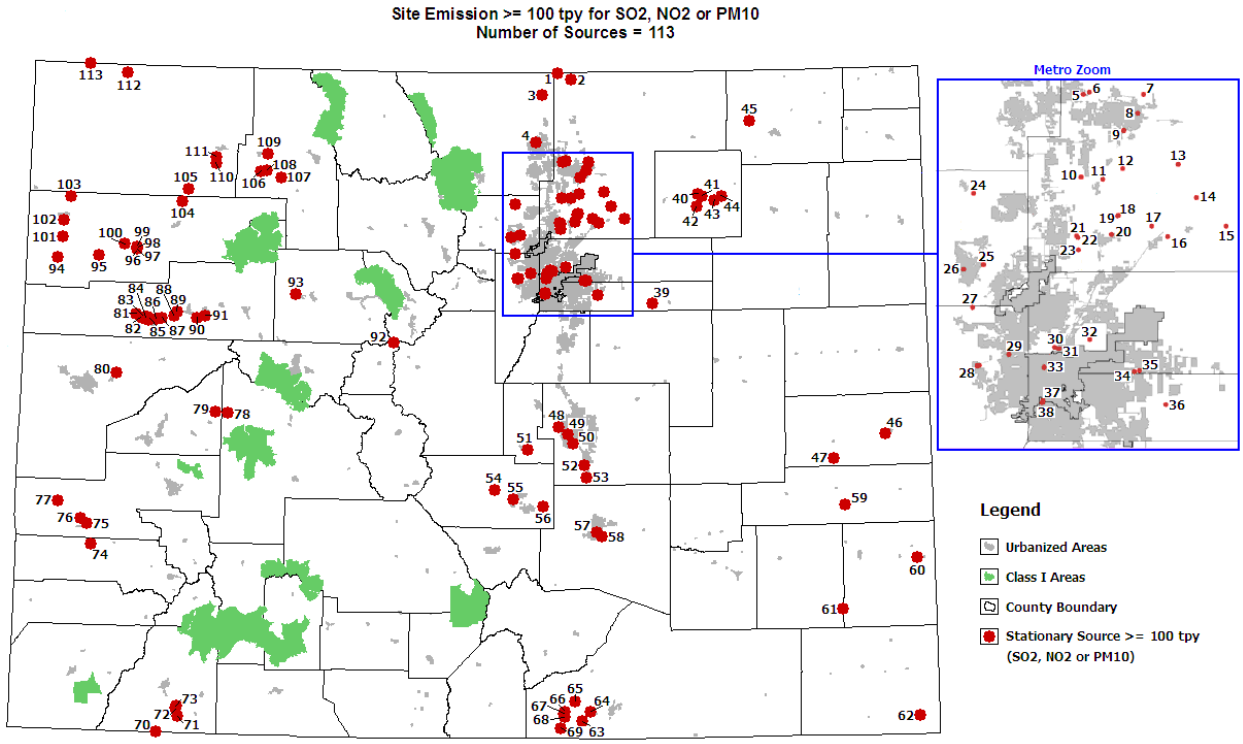


Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20

ArcGIS DATA - Statewide Sources over 100 tpy for SO2, NOx and PM10 (based on 2007 data)

Count	FACILITY NAME	SO2 [tpy]	NO2 [tpy]	PM10 [tpy]	Q [tpy]	Closest CIA	d [km]	Q/d
1	PLATTE RIVER POWER AUTHORITY - RAWHIDE	854	1,808	134	2,796	Rocky Mnt NP	56.0	49.9
2	CEMEX INC. - LYONS CEMENT	87	2,479	418	2,984	Rocky Mnt NP	24.8	120.3
3	PUBLIC SERVICE CO - VALMONT	749	2,355	58	3,162	Rocky Mnt NP	34.8	90.9
4	COLORADO ENERGY NATIONS CORPORATION	2,626	1,786	42	4,453	Rocky Mnt NP	54.5	81.7
5	PUBLIC SERVICE CO - CHEROKEE	7,116	10,205	261	17,581	Rocky Mnt NP	65.3	269.2
6	PUBLIC SERVICE CO - ARAPAHOE	2,496	2,922	178	5,595	Rocky Mnt NP	73.3	76.3
7	PUBLIC SERVICE CO - PAWNEE	13,073	4,645	193	17,911	Rocky Mnt NP	155.7	115.0
8	COLORADO SPRINGS UTILITIES - DRAKE	8,431	3,826	251	12,507	Great Sand Dunes NP	114.0	109.7
9	COLORADO SPRINGS UTILITIES - NIXON	3,883	2,656	129	6,668	Great Sand Dunes NP	104.4	63.9
10	AQUILA INC. - W.N. CLARK STATION	1,480	869	44	2,393	Great Sand Dunes NP	58.7	40.8
11	HOLCIM (US) INC. PORTLAND CEMENT	372	2,589	288	3,250	Great Sand Dunes NP	66.0	49.2
12	PUBLIC SERVICE CO - COMANCHE	13,854	8,415	178	22,447	Great Sand Dunes NP	84.5	265.6
13	TRI STATE GENERATION - NUCLA	1,509	1,716	101	3,327	Black Canyon NP	70.6	47.1
14	PUBLIC SERVICE CO - CAMEO	2,586	1,051	112	3,750	Black Canyon NP	70.5	53.2
15	PUBLIC SERVICE CO - HAYDEN	2,657	7,694	284	10,634	Mt Zirkel WA	31.6	336.5
16	TRI STATE GENERATION - CRAIG	3,586	16,807	235	20,628	Flat Tops WA	47.7	432.4
	Totals:	65,358	71,821	2,906				

Note that the APEN reports may not represent actual annual emissions, as Colorado Regulation 3 requires APEN reports to be updated every five years if no significant emissions increases have occurred at the source. Further, sources do not pay APEN emission fees on fugitive dust, thus sources with significant fugitive dust emissions may report potential rather than actual emissions in the APEN. The state contacted sources to ensure that actual emissions were used as much as possible since many sources over-estimate emissions in APENs. This ensures that correct emissions are used for the purposes of Reasonable Progress.

Set forth below are summaries of each of the sixteen significant sources. Many of these are BART sources, and emission control analyses and requirements for those sources are documented in Chapter 6 of this document. The BART determinations represent best available retrofit control and also satisfy RP requirements, and no further assessment of emissions controls for these facilities is necessary for reasonable progress during this planning period. In this regard, the state has already conducted BART analyses for its BART sources that are largely based on an assessment of the same factors to be addressed in establishing RPGs. Thus, Colorado has reasonably concluded that any control requirements imposed in the BART determination also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 4-2 (June 2007).

1. The state has determined that Platte River Power Authority"s Rawhide Power Plant (unit 1) is a subject-to-RP source and has conducted an emission control analysis for the unit (see below).
2. The CEMEX Portland cement manufacturing facility in Lyons, Colorado, is a subject-to-BART source that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The state has determined that the CEMEX BART determinations for the kiln and the dryer (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period.
3. The Public Service Company of Colorado (PSCo) Valmont Power Plant (unit 5) is a subject-to-BART source that is included in a better than BART alternative for SO2

and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the state has determined that the facility"s closure by 2018 satisfies the PM BART/RP requirements in this planning period.

4. The Colorado Energy Nations Corporation (CENC) operates two subject-to-BART industrial boilers (boilers 4 & 5) that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The CENC BART determination for these two boilers (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period. For boiler 3, the state has determined it to be subject-to-RP and has conducted an emission control analysis for the boiler (see below).
5. The PSCo Cherokee Power Plant has four units (1, 2, 3 & 4); unit 4 is a subject-to-BART source. All of the units are included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of units 1, 2 and 3 by 2018 satisfies the PM RP requirements in this planning period. For unit 4, the BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
6. The PSCo Arapahoe Power Plant (units 3 & 4) is a subject-to-RP source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of unit 3 by 2018 satisfies the PM RP requirements in this planning period; for unit 4 the conversion to repower from coal to natural gas satisfies the PM RP requirements in this planning period.
7. The PSCo Pawnee Power Plant (unit 1) is a subject-to-BART source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. The BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
8. The Colorado Springs Utilities (CSU) Drake Power Plant (units 5-7) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Drake BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
9. The state has determined that the CSU Nixon Plant (unit 1) and the co-located Front Range Power Plant are subject-to-RP sources and has conducted emission control analyses for these sources (see below).
10. The state has determined that the Black Hills Energy Clark Power Plant (units 1 and 2) is a subject-to-RP source and has conducted an emission control analysis for the source (see below).
11. The state has determined that the Holcim Portland cement manufacturing facility (kiln and dryer) is subject-to-RP and has conducted an emission control analysis for the source (see below).
12. The PSCo Comanche Power Plant (units 1 and 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Comanche BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.

13. The state has determined that the Tri-State Generation and Transmission Association"s Nucla Power Plant is subject-to-RP and has conducted an emission control analysis for the source (see below).
14. The state has determined that the PSCo Cameo Power Plant is subject-to-RP. With the closure of the facility by 2012, the SO2, NOx, and PM RP requirements are satisfied in this planning period. A regulatory closure requirement is contained in this chapter and in Regulation No. 3.
15. The PSCo Hayden Power Plant (units 1 & 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Hayden BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
16. The Tri-State Generation and Transmission Association"s Craig Power Plant has three units (1, 2, and 3); units 1 & 2 are subject-to-BART that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The BART determinations for units 1 and 2 (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period. The state has determined that unit 3 is subject-to-RP and has conducted an emission control analysis for the unit (see below).

Consequently, there are seven significant sources identified as subject-to-RP that Colorado has evaluated for controls in the RP analysis process:

- Rawhide Unit 1
- CENC Boiler 3
- Nixon Unit 1
- Clark Units 1, 2
- Holcim Kiln, Dryer
- Nucla
- Craig Unit 3

8.5 Evaluation of Point Sources for Reasonable Progress

In identifying an appropriate level of control for RP, Colorado took into consideration the following factors:

(1) The costs of compliance,
(2) The time necessary for compliance,
(3) The energy and non-air quality environmental impacts of compliance, and
(4) The remaining useful life of any potentially affected sources.

Colorado has concluded that it also appropriate to consider a fifth factor: the degree of visibility improvement that may reasonably be anticipated from the use of RP controls. States have flexibility in how they take these factors into consideration, as well as any other factors that the state determines to be relevant. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 5-1 (June 2007).

8.5.1 Rationale for Point Source RP Determinations

Similar to the process for determining BART as described in Chapter 6, in making its RP determination for each Colorado source, the state took into consideration the five factors on a case-by case basis, and for significant NOx controls the state also utilized the guidance criteria set forth in Section 6.4.3 consistent with the factors. Summaries of the state"s facility-specific consideration of the factors and resulting determinations for each RP source are provided in this Chapter 8. Documentation reflecting the state"s analyses and supporting the state"s RP determinations, including underlying data and detailed descriptions of the state"s analysis for each facility, are provided in Appendix D of this document and the TSD.

8.5.1.1 The costs of compliance. The Division requested, and the companies provided, source-specific cost information for each RP unit. The cost information relates primarily to the installation and operation of new SO2 and NOx control equipment. The cost for each unit is summarized below, and the state"s consideration of this factor for each source is presented in detail in Appendix D.

8.5.1.2 The time necessary for compliance.

Regulation No 3, Part F, Section VI.B.4. requires facilities subject to RP determinations to submit a compliance plan within 60 days of SIP approval. Based on Colorado facility submittals, the Division anticipates that the time necessary for facilities to complete design, permitting, procurement, and system startup, after SIP approval, would be approximately 3 - 5 years. This timeframe may vary somewhat due to the necessary major maintenance outage with other regionally affected utilities.

8.5.1.3 The energy and non-air quality environmental impacts of compliance. This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each RP unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

8.5.1.4 The remaining useful life of the source. For those sources set to retire by 2018, the state established a regulatory closure requirement in this chapter and in Regulation No. 3. For those sources not expected to retire over the next twenty years, this factor did not affect any of the state"s RP determinations.

8.5.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of RP. The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of RP control, where relevant and the information was available, although degree of visibility improvement is not an express element of four factors to be considered during reasonable progress under EPA"s federal regulations and guidelines. Modeling information where relevant and available for each RP determination is presented below and in Appendix D.

8.5.1.6 Overview of the RP Determinations for Each Source. This section presents an overview of the RP determinations for the significant point sources not addressed in Chapter 6.

The regional haze rule gives the states broad latitude on how the four statutory factors, and any other factors a state deems to be relevant, may be considered to determine the appropriate controls for RP. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the factors in reaching a determination. The manner and method of consideration is left to the state"s discretion; states are free to determine the weight and significance to be assigned to each factor.

The Division has reviewed available particulate controls applicable to RP facilities. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM". *See,* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix D.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 8, in Appendix D and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See,* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix D.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate.

When determining the emission rates for each source, the state referred to the available literature and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that RP relates to retrofitting sources (vs. new or reconstructed facilities), a review of other BART and RP determinations used to better substantiate the source specific information provided by the source.

For the purposes of the RP review for the three pollutants that the state is assessing for the seven facilities, SO2 and PM have been assessed utilizing the factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and

certain other sources require a case by case review because of their unique nature. For NOx controls on reasonable progress electric generating units, for reasons described below, the state is employing guidance criteria to aid in its RP assessment, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of control for these sources.

With respect to SO2 emissions, there are currently ten flue gas desulphurization lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[39] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. The state has determined in the past that these systems can be cost-effective for sources in Colorado. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are currently no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx controls at significant sources for individual units for visibility improvement under the Regional Haze rule, for reasonable progress, the state has considered the relevant factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight. In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors.

[39] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

Accordingly, as part of its reasonable progress factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state"s calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state"s calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state"s general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of RP control on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state"s extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado"s retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[40] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[41] The $5,000/ton criterion is also consistent with and within the range of the state"s implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control

[40] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[41] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for reasonable progress, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, have the ability to provide significant NOx reductions, but also have initial capital dollar requirements that can approach or exceed $100 million per unit.[42] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[43] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[44] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the relevant factors for reasonable progress, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

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[42] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[43] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[44] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. Colorado is applying these same criteria to RP sources, as a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

8.5.2 Point Source RP Determinations

The following summarizes the RP control determinations that will apply to each source.

Table 8-2 RP Control Determinations for Colorado Sources

Emission Unit	Assumed** NOx Control Type	NOx Emission Limit	Assumed** SO_2 Control Type	SO_2 Emission Limit	Assumed** Particulate Control and Emission Limit
Rawhide Unit 101	Enhanced Combustion Control*	0.145 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
CENC Unit 3	No Control	246 tons per year (12-month rolling total)	No Control	1.2 lbs/MMBtu	Fabric Filter Baghouse* 0.07 lb/MMBtu
Nixon Unit 1	Ultra-low NOx burners with Over-Fire Air	0.21 lb/MMBtu (30-day rolling average)	Lime Spray Dryer	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Clark Units 1 &2	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Holcim - Florence Kiln	SNCR	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	Wet Lime Scrubber*	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	Fabric Filter Baghouse* 246.3 tons/year
Nucla	No Control	0.5 lb/MMBtu (30-day rolling average)	Limestone Injection*	0.4 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 3	SNCR	0.28 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.15 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu PM10
Cameo	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

For all RP determinations, approved in the federal State Implementation Plan, the state affirms that the RP emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional Haze analyses or Regional Haze controls will be required by the state during this timeframe.

The following presents an overview of Colorado"s RP control determinations:

8.5.2.1 RP Determination for Platte River Power Authority - Rawhide Unit 101

This facility is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. Unit 101 is a 305 MW boiler and is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Platte River Power Authority (PRPA) submitted a "Rawhide NOx Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010.

SO2 RP Determination for PRPA Rawhide Unit 101

Dry FGD Upgrades – As discussed in EPA"s BART Guidelines, electric generating units (EGUs) with existing control achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Rawhide Unit 101 operates a lime spray dryer FGD currently achieving over 72 percent SO2 reduction. The state has elected to consider EPA"s BART Guidelines as relevant to the RP evaluation of Rawhide Unit 101 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of SO_2 scrubber performance additives applicable to the Unit 101 SDA system.
- *Use of more reactive sorbent*: Lime quality is critical to achieving the current emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with existing limits. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. PRPA is already using a highly reactive sorbent, therefore this option is not technically feasible.
- *Increase the pulverization level of sorbent*: The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 SO_2 scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements that are designed to improve the reactivity of the slaked lime-milk slurry.
- *Engineering redesign of atomizer or slurry injection system*: The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-

nozzle design. The state and PRPA concur that PRPA utilizes optimal maintenance and operations; therefore, a lower SO2 emission cannot be achieved with improved maintenance and/or operations.

Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 – SO2 Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Fuel switching – NG	906	$237,424,331	$262,169

There are no energy and non-air quality impacts associated with this alternative.

There are no remaining useful life issues for the alternative as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to more stringent SO2 emission limits as a demonstration are as follows:

SO2 Control Method	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.11	
Existing Dry FGD	0.09	0.01
Dry FGD – tighter limit	0.07	0.03
Fuel switching – NG	0.00	0.87

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that SO2 RP is the following SO2 emission rates:

Rawhide Unit 101: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the installation and operation of lime spray dryers (LSD). The state has determined that these emissions rates are achievable without additional capital investment through the four-factor analysis. Upgrades to the existing SO2 control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO2 limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

Particulate Matter RP Determination for PRPA Rawhide

The state has determined that the existing Unit 101 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}.

The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

NOx RP Determination for PRPA Rawhide

Enhanced combustion control (ECC), selective non-catalytic reduction (SNCR), fuel switching to natural gas (NG), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Rawhide Unit 101. Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Rawhide Unit 101 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
ECC	448	$288,450	$644
SNCR	504	$1,596,000	$3,168
Fuel switching – NG	545	$237,424,331	$435,681
SCR	1,185	$12,103,000	$10,214

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.302	
ECC	0.126	0.45
SNCR	0.121	0.46
Fuel Switching – NG	0.118	0.47
SCR	0.061	0.59

It should be noted that the daily maximum (3-yr) value of 0.302 lb/MMBtu was a substituted value from CAMD. The next highest 24-hour value was 0.222 lb/MMBtu, 26% lower than the modeled value. However, the Division did not conduct revised modeling since it was determined that it would not change the State"s RP determination.

Switching to natural gas was eliminated from consideration due to the excessive cost/effectiveness ratio and degree of visibility improvement less than 0.5 dV.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Rawhide Unit 101 is the following NOx emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements of 0.45 delta dv, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit (0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state.

A complete analysis that supports the RP determination for the Rawhide facility can be found in Appendix D.

8.5.2.2 RP Determination for Colorado Energy Nations Company (CENC) Boiler 3

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boiler 3 is considered by the State to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. CENC submitted a “Reasonable Progress Control Evaluation” on May 7, 2010 as well as additional relevant information on February 8, 2010.

The CENC facility includes five coal-fired boilers that supply steam and electrical power to Coors Brewery. Three of the boilers emit above 40 tons or more of haze forming pollution. Of these three boilers, Units 4 and 5 are subject to BART, and Unit 3 is subject to RP. Unit 3 is rated as follows: 225 MMBtu/hr, which is approximately equivalent to 24 MW, based on the design heat rate.

SO2 RP Determination for CENC – Boiler 3

Dry sorbent injection (DSI) and fuel switching to natural gas were determined to be technically feasible for reducing SO2 emissions from Boiler 3. Dry FGD is not technically feasible for Boiler 3 due to space constraints onsite. These options were considered as potentially RP by the state. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by PRPA it was evaluated by the state.

Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

CENC Boiler 3 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI – Trona	147	$1,340,661	$9,114
Fuel Switching – Natural Gas	245	$1,428,911	$5,828

DSI – Trona and fuel switching to natural gas were eliminated from consideration due to excessive cost/effectiveness ratio.

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce minimal visibility impacts (<<0.10 dv).

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is an emission rate of:

CENC Boiler 3: 1.2 lbs/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<< 0.10 dv) afforded.

Particulate Matter RP Determination for CENC – Boiler 3

The state has determined that the existing Boiler 3 regulatory emissions limit of 0.07 lb/MMBtu (PM/PM10) corresponding with the original Industrial Boiler MACT standard represents the most stringent control option. The units are exceeding a PM control efficiency of 90%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CENC – Boiler 3

Flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), rotating overfire air (ROFA) fuel switching to natural gas, and three options for selective catalytic reduction (RSCR, HTSCR, and LTSCR) were determined to be technically feasible for reducing NOx emissions at CENC Boiler 3. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by CENC it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

CENC Boiler 3 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
FGR	33.7	$1,042,941	$30,929
SNCR	50.6	$513,197	$10,146
Fuel switching – NG	84.3	$1,428,911	$16,950
ROFA w/ Rotamix	77	$978,065	$9,496
Regenerative SCR	96.3	$978,065	$10,160
High temperature SCR	125.6	$1,965,929	$15,651
Low temperature SCR	144.5	$2,772,286	$19,187

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce visibility impacts below the guidance visibility criteria discussed in section 8.4 above.

All NOx control options were eliminated from consideration due to the excessive cost/effectiveness ratios and small degree of visibility improvement.

Based on review of historical actual load characteristics of this boiler, the state determines to be appropriate an annual NOx ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor for a variety of reasons specific to Boiler 3 further explained in Appendix D.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Boiler 3 is the following NOx emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with predicted minimal visibility improvement (<< 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze SIP, and thus not reasonable

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is likely below the state's guidance criteria of 0.2 dv and 0.5 dv,

respectively (as demonstrated in the BART determination for CENC Boiler 4). Moreover, the incremental visibility improvement associated with SNCR or SCR is likely not substantial when compared to the visibility improvement achieved by the selected limits. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Boiler 3.

A complete analysis that supports the RP determination for the CENC facility can be found in Appendix D.

8.5.2.3 RP Determination for Colorado Springs Utilities' - Nixon Unit 1

The Nixon plant is located in Fountain, Colorado in El Paso County. Nixon Unit 1 and two combustion turbines at the Front Range Power Plant are considered by the Division to be eligible for the purposes of Reasonable Progress, being industrial sources with the potential to individually emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Colorado Spring Utilities (CSU) provided RP information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 and additional relevant information on May 10, 2010.

SO2 RP Determination for CSU – Nixon

Dry sorbent injection (DSI) and dry FGD were determined to be technically feasible for reducing SO2 emissions from Nixon. These options were considered as potentially RP by the state. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nixon Unit 1 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
DSI – Trona	2,473	$9,438,692	$1,997
Dry FGD @ 78% control (0.10 lb/MMBtu annual average)	3,215	$12,036,604	$3,744
Dry FGD @ 85% control (0.07 lb/MMBtu annual average)	3,392	$13,399,590	$3,950

The energy and non-air quality impacts of the remaining alternatives are as follows:

- DSI – reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Nixon – Unit 1	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.45	
DSI	0.18	0.44
Dry FGD (LSD)	0.10	0.46
Dry FGD (LSD)	0.07	0.50

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state"s experience, 30-day SO2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO2 emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is the following SO2 emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% SO_2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: $3,744 per ton SO_2 removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

Particulate Matter RP Determination for CSU – Nixon

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limits is RP for $PM/PM_{10.}$ The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for CSU – Nixon

Ultra low NOx burners (ULNB), SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Nixon Unit 1.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives.

Nixon Unit 1 - NO_x Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Ultra-low NOx Burners (ULNBs)	471	$567,000	$1,203
Overfire Air (OFA)	589	$403,000	$684
ULNBs+OFA	707	$907,000	$1,372
Selective Non-Catalytic Reduction (SNCR)	707	$3,266,877	$4,564
ULNB/SCR layered approach	1,720	$11,007,000	$6,398
Selective Catalytic Reduction (SCR)	1,720	$11,010,000	$6,400

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Nixon – Unit 1	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Max (3-yr)	0.26	
ULNB	0.21	0.15
OFA	0.19	0.15
ULNB+OFA	0.18	0.16
SNCR	0.18	0.16
ULNB + SCR	0.07	0.24
SCR	0.07	0.24

SCR options were eliminated from consideration due to the excessive cost/effectiveness ratios and degree of visibility improvement.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state‟s experience and other state BART proposals, 30-day NOx rolling average emission rates

are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Nixon Unit 1 is the following NOx emission rates:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that the ultra-low NOx burners with over-fire air-based emissions limit is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above RP determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.01 dv for SNCR and 0.09 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Nixon Unit 1.

A complete analysis that supports the RP determination for the Nixon Plant can be found in Appendix D.

8.5.2.4 RP Determination for Black Hills Clark Facility Units 1 and 2

Black Hills/Colorado Electric Utility Company, LP informed the state that the Clark Station in the Cañon City, Colorado area will be shutdown 12/31/2013, resulting in SO2, NOx and PM reductions of approximately 1,457, 861, and 72 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

8.5.2.5 RP Determination for Holcim's Florence Cement Plant

The Holcim Portland cement plant is located near Florence, Colorado in Fremont County, approximately 20 kilometers southeast of Canon City, and 35 kilometers northwest of Pueblo, Colorado. The plant is located 66 kilometers from Great Sand Dunes National Park.

In May 2002, a newly constructed cement kiln at the Portland Plant commenced operation. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. As a result, Holcim was able to increase clinker production from approximately 800,000 tons of clinker per year to a permitted level of 1,873,898 tons of clinker per year, while reducing the level of NO_X, SO_2, and PM/PM_{10} emissions on a

pound per ton of clinker produced basis. As a part of this project, Holcim also installed a wet lime scrubber to reduce the emissions of sulfur oxides.

The Portland Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. The raw materials are further crushed and blended and then directed to the kiln feed bin from where the material is introduced into the kiln.

The dual string 5-stage preheater/precalciner/kiln system features a multi-stage combustion precalciner and a rotary kiln. The kiln system is rated at 950 MMBtu per hour of fuel input with a nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types and amounts (with nominal fuel heat values, where reported):

- coal (269,262 tons per year [tpy] @ 11,185 Btu/pound);
- tire derived fuel (55,000 tpy @ 14,500 Btu/pound);
- petroleum coke (5,000 tpy @ 14,372 Btu/pound);
- natural gas (6,385 million standard cubic feet @ 1,000 Btu/standard cubic foot);
- dried cellulose (55,000 tpy); and
- oil, including non-hazardous used oil (4,000 tpy @ 12,000 Btu/pound).

The clinker produced by the kiln system is cooled, grounded and blended with additives and the resulting cement product is stored for shipment. The shipment of final product from the plant is made by both truck and rail.

Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to atmosphere. These emissions are currently controlled by fabric filters (i.e., baghouses) for PM/PM_{10}, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for SO_2, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-NO_X precalciner, indirect firing, Low-NO_X burners, staged combustion and a Linkman Expert Control System for NO_X, and by the use of good combustion practices for both NO_X and SO_2.In addition to the kiln system/main stack emissions, there are two other process points whose PM/PM_{10} emissions exceed the Prevention of Significant Deterioration (PSD) significance level thresholds and were considered as a part of this Reasonable Progress analysis: 1) the raw material extraction and alkali bypass dust disposal operations associated with the quarry, and 2) the cement processing operations associated with the finish mill. Emissions from the quarry are currently controlled through a robust fugitive dust control plan and emissions from the finish mills are controlled by a series of baghouses.

Holcim did not initially complete a detailed four-factor analysis, though it did submit limited information on the feasibility of post-combustion NO_X controls for the kiln system. In late October through early December 2010, Holcim did submit detailed information, including data on baseline emissions, existing controls and additional control options, and visibility modeling to support the reasonable progress determination process. This section has been revised to reflect this additional information.

CALPUFF modeling was conducted by the Division for the kiln system, as a part of our original analysis, using a SO_2 emission rate of 99.17 lbs/hour, a NO_X emission rate of

837.96 pounds per hour (lbs/hour), and a PM_{10} emission rate of 19.83 lbs/hour. The modeling indicates a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Holcim provided additional visibility modeling results in a submittal made in late October 2010.

Because of the high level of existing fugitive dust controls employed at the quarry and the baghouse controls already installed on the finish mill emission points, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable additional controls on these points. Accordingly, the state has determined that no additional visibility analysis is necessary or appropriate since even the total elimination of the emissions from the quarry and finish mill would not result in any meaningful visibility improvement. For the quarry, the current PM_{10} emission limitation is 47.9 tpy (fugitive) and for the finish mill it is 34.3 tpy (point source). These limitations are included in the existing Holcim Portland Plant construction permit.

SO_2 RP Determination for Holcim Portland Plant – Kiln System

In addition to good combustion practices and the inherent recycling and scrubbing of acid gases by the raw materials, such as limestone, used in the cement manufacturing process, the Portland Plant kiln system has a tail-pipe wet lime scrubber. Holcim has reported that this combination of controls achieves an overall sulfur removal rate of 98.3% for the kiln system, as measured by the total sulfur input in to the system versus the amount of sulfur emitted to atmosphere. Holcim has also reported that they estimate that the wet scrubber at the Portland Plant achieves an overall removal efficiency of over 90% of the SO_2 emissions entering the scrubber. This control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding SO2 emissions rates. The facility is currently permitted to emit 1,006.5 tpy of SO2 from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 1.08 pounds of SO2 per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for SO2). The actual kiln SO2 emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 0.51 pound of SO2 per ton of clinker, with a standard deviation of 0.26 pound per ton. The highest annual emission rate in the baseline years was 0.95 pound per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for SO_2. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emissions limit of 1.30 pounds of SO_2 per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability. The long-term annual limit was calculated at 721.4 tpy by multiplying the long-term baseline SO_2 value

of 0.77 lb/ton (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton.

Because there are no changes to the existing controls for SO2, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

For the kiln system, based upon our consideration and weighing of the four factors, the state has determined that no additional SO2 emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technologies – the inherent recycling and scrubbing effect of the process itself followed by a tail-pipe wet lime scrubber. The RP analysis provides sufficient basis to establish a short-term SO_2 emission limit of 1.30 pound per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of SO_2 per year (12-month rolling total) for the kiln system. There is no specific visibility improvement associated with this emission limitation.

Finally, on August 9, 2010, EPA finalized changes to the New Source Performance Standards (NSPS) for Portland Cement Plants and to the Maximum Achievable Control Technology standards for the Portland Cement Manufacturing Industry (PC MACT). The NSPS requires, new, modified or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO2 per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, it is important to note that the estimated level of control achieved by Holcim"s wet scrubber (~90%) is consistent with the level of control prescribed by the NSPS for new sources.

Particulate Matter RP Determination for Holcim Portland Plant – Kiln System

The state has determined that the existing fabric filter baghouses installed on the kiln system represent the most stringent control option. Holcim has reported a nominal control efficiency for the kiln system baghouses at 99.5%. The units are exceeding a PM control efficiency of 95% and this control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding PM_{10} emissions rates. The facility is currently permitted to emit 246.3 tpy of PM_{10} from the kiln system main stack (includes emissions from the clinker cooler). At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 0.26 pound of PM_{10} per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for PM_{10}). The actual kiln system PM_{10} emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) average to a rate of 0.16 pound of PM_{10} per ton of clinker (combined emissions from main stack). This value is derived from the limited annual stack test data, which are effectively snapshots in time, and does not take into account the short-term inherent variability in the manufacturing process, raw material and fuel.

Because there are no changes to the existing controls for PM_{10}, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

As a part of our original analysis, the state modeled possible visibility improvements associated with two emission rates – the baseline emission rate of 0.08 pound of PM_{10} per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of PM_{10} per ton of clinker (9.92 lbs/hour). This analysis assumed the baseline emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. There was no change to the 98th percentile impact deciview value from 19.83 lbs/hour to 9.92 lbs/hour and therefore, no visibility improvement associated with this change. The state"s modeling results showed that the most significant contributors to the visibility impairment from the Portland Plant were nitrates (NO_3) followed by sulfates (SO_4).The contribution of PM_{10} to the total visibility impairment was insignificant in the analysis. The level of PM_{10} emissions evaluated had no discernable impact on visibility.

For the kiln system, based upon our consideration and weighing of the four factors and the very limited impact of PM_{10} emissions from the kiln system on visibility impairment, the state has determined that no additional PM_{10} emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technology – fabric filter baghouses. These baghouses and the current permit limit of 246.3 tpy of PM_{10} (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler) represent RP for this source. Furthermore, the Portland Plant is subject to the PC MACT and the recent amendments to the PC MACT include new, lower standards for PM emissions. As an existing facility, the Portland Plant kiln system will be subject to this standard once it becomes effective on September 9, 2013. Compliance with the new PC MACT PM emission standards will result in further reductions in the PM_{10} emissions.

NO_X RP Determination for Holcim Portland Plant – Kiln System

There are a number of technologies available to reduce NO_X emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-NO_X burners, staged combustion, a low-NO_X precalciner, and a Linkman Process Control Expert system). These include water injection (the injection of water or steam into the main flame of a kiln to act as a heat sink to reduce the flame temperature), and selective non-catalytic reduction (SNCR). These technologies were determined to be technically feasible and appropriate for reducing NO_X emissions from Portland cement kilns.

As further discussed in Appendix D, the state has determined that selective catalytic reduction (SCR) is not commercially available for the Portland Plant cement kiln system. Presently, SCR has not been applied to a cement plant of any type in the United States. Holcim notes that the major SCR vendors have either indicated that SCR is not commercially available for cement kilns at this time, or if they are willing to provide a quotation for an SCR system, the associated limitations that are attached with the quote severely undercut the efficacy of the system. The state does not believe that a limited

use - trial basis application of an SCR control technology on three modern kilns in Europe constitutes reasonable “available” control technology for purposes of RP at the Holcim Portland Plant. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is “available” for purposes of retrofitting such control technology on an existing source.

In the preamble to the recently finalized changes to the Portland Cement MACT/NSPS, EPA stated: “However, although SCR has been demonstrated at a few cement plants in Europe and has been demonstrated on coal-fired power plants in the US, the Agency is not satisfied that it has been sufficiently demonstrated as an off-the-shelf control technology that is readily applicable to cement kilns.” Based on our research and EPA"s analysis for the MACT/NSPS standards, the state has eliminated SCR as an available control technology for purposes of this RP analysis.

The design of the Holcim Portland Plant does allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia-like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NO_X to elemental nitrogen. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant. In April 2008, Holcim provided information to the state on SNCR systems that was based on trials that were conducted at the plant in the 4th quarter of 2006. Holcim estimated that NO_X emissions could be reduced in the general range of 60 to 80% (based on a 1,000 pound per hour emission rate) at an approximate cost of $1,028 per ton. This was based on a short-term testing and showed considerable ammonia slip which could cause significant environmental, safety and operational issues.

The facility is currently permitted to emit 3,185.7 tpy of NOX from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 3.40 pounds of NOX per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NOX). The actual kiln NOX emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 3.43 pounds of NOX per ton of clinker, with a standard deviation of 0.21 pound per ton. The highest annual emission rate in the baseline years was 3.67 pounds per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for NOX. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emission rate of 4.47 pounds of NOX per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability.

Holcim is permitted to burn up to 55,000 tpy of TDF annually and has been using TDF during the baseline years. Use of TDF as a NOX control strategy has been well

documented and recognized by EPA. A reduction in NOX emissions of up to 30% to 40% has been reported. Since the TDF market and possible associated TDF-use incentives are unpredictable and TDF"s long-term future availability is unknown, the baseline emission rate was adjusted upward by a conservative factor of 10% to account for the NOX reduction in the baseline years as a result of the use of TDF during this baseline period that might not be available in future years. This increased the baseline 30-day rolling average emissions rate from 4.47 to 4.97 pounds of NOX per ton of clinker.

An SNCR control efficiency of 50% is feasible for the Portland Plant kiln that already has number of technologies available to reduce NOX emissions including indirect firing, low-NOX burners, staged combustion, a low-NOX precalciner, and a Linkman Process Control Expert system. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, (conservative estimate) for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the overall SNCR control efficiency for the main stack will be 45%.

Based on the above discussion, the 30-day rolling average short-term limit was calculated at 2.73 pounds of NOX per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of NOX per ton clinker by 10% for TDF and then accounting for SNCR 45% overall control efficiency [4.47/0.9*(1-0.45) = 2.73]. The long-term annual limit was calculated at 2,086.8 tpy by adjusting upward the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) by 10% for TDF and then accounting for SNCR 45% overall control efficiency [3.64/0.9*(1-0.45) = 2.23 lb/ton]. This calculated value of 2.23 pounds per ton was then multiplied by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy NOX limit.

Because SNCR with existing LNB is technically and economically feasible, the state did not further consider water injection because the level of control associated with this option is not as high as with SNCR.

The following table lists the most feasible and effective option (SNCR):

NOx Control Technology	Estimated Control Efficiency	30-day Rolling Average Emissions (lb/ton of Clinker)	Annual Controlled NOx Emissions (tpy)
Baseline NOx Emissions	-	4.97	3,185.7*
SNCR w/ existing LNB	45%**	2.73	2,086.8

* Defaulted to the permit limit since the calculated baseline was higher.

** This is calculated based on the 50% SNCR removal efficiency and 10% bypass

There are no significant associated energy and non-air quality impacts for SNCR in operation on a Portland cement plant. There are no remaining useful life issues for the

source, as the state has presumed that the source will remain in service for the 20-year amortization period.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

Holcim Portland Plant – Kiln System				
NOx Control Technology	NOx Emission Reduction (tons/yr)	Annualized Cost ($/yr)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline NOx Emissions	-			
SNCR w/existing LNB (45% control)	1,098.9	$2,520,000*	$2,293	-

* Annualized cost is based on the estimates provided by Holcim. The state believes that the $2,293/ton value is generally representative of control costs for the scenario evaluated in this RP analysis.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed NO_X RP limitations. The following table lists the projected visibility improvements for NO_X controls, as identified by Holcim:

Holcim Portland Plant – Kiln System		
NOx Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NOx, 586 lb/hr SO_2, 86.4 lb/hr PM_{10})	0.814	N/A
SNCR w/ existing LNB (45% overall NO_X control efficiency) Limits of **2.73 lb/ton** (30-day rolling average) and **2,086.8 tons per year** (based on modeled emission rates of 750 lb/hr NO_X, 586 lb/hr SO_2, 86.4 lb/hr PM_{10})	0.526	0.288

For the kiln, the state has determined that SNCR w/existing LNB is the best NO_X control system available with NO_X RP emission limits of 2.73 pounds per ton of clinker (30-day rolling average) and 2,086.8 tons per year (12-month rolling total). The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This RP determination affords the most NO_X reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement.

A complete analysis that further supports the RP determination for the Holcim Portland Plant can be found in Appendix D.

8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Nucla – Unit 4

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO2 emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs. Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nucla Unit 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Limestone Injection Improvements	526	$914,290	$4,161
Spray Dry Absorber (dry FGD)	1,162	$7,604,627	$6,547
Limestone Injection Improvements + dry FGD	1,254	$9,793,222	$7,808

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO2 reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage.

There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed "limestone injection improvements") was evaluated and determined to not be feasible under certain operating conditions. The system cannot be „run harder" with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

PM10 RP Determination for Nucla – Unit 4

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Nucla – Unit 4

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State"s estimates vary between 10 – 40% NOx reduction potential, which correlates to between $3,000 - $17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 – 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure above, and within approximately 115 kilometers to five Class I areas, including Utah"s Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO2 and NOx Controls for Nucla

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options. A final analysis that addresses the state"s comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division"s approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013.

A complete analysis that supports the RP determination for the Nucla facility can be found in Appendix D.

8.5.2.7 RP Determination for Tri-State Generation and Transmission Association's Craig Facility Unit 3

The Tri-State Craig Station is located in Moffat County about 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. Craig Units 1 and 2 are subject to BART. Craig Unit 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2,

PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Craig – Unit 3

Dry FGD Upgrades - As discussed in EPA"s BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Craig Unit 3 operates a [lime spray dryer FGD] currently achieving over 80 percent SO2 reduction. The state considers EPA"s BART Guidelines relevant to the RP evaluation of Craig Unit 3 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of SO_2 scrubber performance additives applicable or commercially available for the Unit 3 SDA system.

- *Use of more reactive sorbent/Increase the pulverization level of sorbent*: The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial pebble lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that TriState cannot use a more reactive sorbent or increase the pulverization level of sorbent.

- *Engineering redesign of atomizer or slurry injection system*: Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO2 removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling SO_2 limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA"s Clean Air Markets

Division website, the state has determined that this emissions rate is achievable without additional capital investment.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 3	
	SO2 Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.33	
Dry FGD	0.15	0.26
Dry FGD	0.07	0.38

The current SO2 emission limits for Craig 3 are:

- 0.20 lb/MMBtu averaged over a calendar day, to be exceeded no more than once during any calendar month;
- 80% reduction of the potential combustion concentration of SO2, determined on a 30-day rolling average basis
- 2,125 tons/year annual emission limit

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of existing dry FGD controls. An SO2 limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

PM10 RP Determination for Craig – Unit 3

The State has determined that the existing Unit 3 regulatory emissions limits of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Craig – Unit 3

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Unit 3.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 3 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	853	$4,173,000	$4,887
SCR	4,281	$29,762,387	$6,952

SCR was eliminated from consideration due to the excessive cost/benefit ratio.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (2nd half 2009)	0.365	
SNCR	0.240	0.32
SCR	0.070	0.79

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state"s experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.
Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Craig Unit 3 is the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of SNCR. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. For SNCR-based emission rates at Unit 3, the cost per ton of emissions removed, coupled with the

estimated visibility improvements gained, falls with guidance cost criteria discussed in section 8.4 above.

- Unit 3: $4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

A complete analysis that supports the RP determination for the Craig facility can be found in Appendix D.

8.5.2.8 RP Determination for Public Service Company's Cameo Station

Public Service Company informed the state that the Cameo Station east of Grand Junction, Colorado will be shutdown 12/31/2011, resulting in SO2, NOx and PM reductions of approximately 2,618, 1,140, and 225 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

Chapter 9 Long Term Strategy

The Long-Term Strategy (LTS) is required by both Phase 1 (Reasonably Attributable Visibility Impairment) and Phase 2 (Regional Haze) regulations. The LTS" of both phases are to be coordinated.

This chapter contains:

- LTS requirements;
- An overview of the current Reasonably Attributable Visibility Impairment Long Term Strategies (RAVI LTS), adopted by the Commission in 2004 and subsequently approved by EPA;
- A review of the 2004 RAVI LTS and a SIP revision;
- A Regional Haze LTS; and
- Reasonable Progress Goals for each of the state"s 12 mandatory federal Class I areas.

9.1 LTS Requirements

The LTS requirements for reasonably attributable visibility impairment, as described in 40 CFR 51.306, are as follows:

- Submittal of an initial RAVI LTS and 3-year periodic review and revision (since revised to 5-year updates per 40 CFR 51.306(g)) for addressing RAVI;
- Submittal of revised LTS within three years of state receipt of any certification of impairment from a federal land manager;
- Review of the impacts from any new or modified stationary source;
- Consultation with federal land managers; and
- A report to the public and EPA on progress toward the national goal.

The LTS requirements for Regional Haze (RH), as described in 40 CFR 51.308(d)(3), are as follows:

- Submittal of an initial LTS and 5-year progress review per 40 CFR 51.308(g) that addresses regional haze visibility impairment;
- Consult with other states to develop coordinated emission management strategies for Class I areas outside Colorado where Colorado emissions cause or contribute to visibility impairment, or for Class I areas in Colorado where emissions from other states cause or contribute to visibility impairment;
- Document the technical basis on which the state is relying to determine its" apportionment of emission reduction obligations necessary for achieving reasonable progress in each Class I area it affects;
- Identify all anthropogenic sources of visibility impairing emissions;
- Consider the following factors when developing the LTS:
  (1) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
  (2) Emission limitations and schedules for compliance to achieve the RP goal;
  (3) Measures to mitigate the impacts of construction activities;

(4) Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;
(5) Source retirement and replacement schedules;
(6) Enforceability of emission limitations and control measures; and
(7) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

The following sections 9.2 and 9.3 address these LTS requirements.

9.2 2004 RAVI Long-Term Strategy

The RAVI LTS was adopted by the Commission in November 2004. It was subsequently approved by EPA in December 2006 and is summarized below.

9.2.1 Existing Impairment

The LTS must have the capability of addressing current and future existing impairment situations as they face the state. Colorado considers that Commission Regulation No. 3, Part B, 5XIV.D ("Existing Impairment") meets this LTS requirement regarding existing major stationary facilities and provides Federal Land Managers (FLMs) the opportunity to certify whether an existing stationary source(s) is likely reasonably attributable to existing visibility impairment and potentially subject to BART. The state believes existing regulations along with strategies and activities outlined below have together provided for reasonable progress toward the national visibility goal under Phase 1 of the visibility protection program. However, a specific requirement associated with the RH rule is found in 40 CFR § 51.306(c) and is intended to bring into harmony the reasonable attribution requirement in place since 1980 and the RH rule. As such, to meet one part of that requirement, the State of Colorado commits to review the long-term strategy as it applies to reasonably attributable impairment, and make revisions, as appropriate, within three years of state receipt of any certification of reasonably attributable impairment from a Federal Land Manager. This is consistent with the current LTS and State Regulation No. 3 noted above. In addition, Regulation 3, Part D, is amended as part of this SIP action to change the current 3 year review cycle to a 5 year cycle to coordinate the RAVI and RH elements together as intended by the RH rule. Elsewhere in this SIP the state has documented measures to be adopted to address the RH element of the rule including BART determinations and strategies identified in Chapter 8- Reasonable Progress.

In a related action, this 5-year update will satisfy Colorado"s requirement for developing emissions estimates from activities on federal lands (Colorado Revised Statute 25-7-105(1)). The state commits to consult with Federal Land Managers to develop a consolidated emissions inventory, which will be brought to the Air Quality Control Commission as part of the 5-year LTS update and then submitted to EPA. After the 2008 emission inventory data submittal, the Consolidated Emission Reporting Rule will be completely replaced by the Air Emissions Reporting Requirements Rule.

Following is a review of the elements contained in the LTS in a chronological order. During the five-year review required by the RH rule, the State of Colorado will add to or

revise this section as needed based on any new findings or actions taken related to RAVI notifications delivered to the state by a FLM.

9.2.1.1 Mt. Zirkel Wilderness

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and local existing stationary sources, namely the Craig and Hayden power stations, contributed to the problem. In 1996 and again in 2001, settlement agreements between various parties and the Hayden and Craig (Units 1 and 2) Generating Stations, respectively, were completed. The state believes significant emission reductions of SO2 and PM effectively address the RAVI in the MZWA associated with the Hayden and Craig (Units 1 & 2) Generating Stations. The state further believes the Hayden and Craig Consent Decrees effectively resolve the certification of impairment brought by the U.S.D.A. Forest Service. The Forest Service indicated its complaint against Hayden and Craig had been satisfied.

9.2.1.2 BART and Emission Limitations

Although RAVI BART determinations were not made by the state regarding Hayden and Units 1 and 2 of Craig generating stations, emission limitations for the two power plants were incorporated into the LTS SIP in August 1996 (Hayden) and April 2001 (Craig Units 1 and 2) and these SIP revisions remain incorporated into the Colorado SIP. The contents of the August 1996 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for Hayden generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference. EPA originally approved this SIP amendment on January 16, 1997. The contents of the April 2001 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for the Craig generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference.

This RH SIP amendment establishes new limits on Hayden Units 1 and 2, and Craig Units 1 and 2, based on a full BART analysis under the current EPA guidelines. Chapter 6 of this SIP (and Appendix C as well as supporting technical support documents) and changes to Regulation No. 3 result in new control requirements for these units to meet BART.

9.2.1.3 Monitoring

It is important to track the effects of the emission changes on visibility and other Air Quality Related Values in and near Mt. Zirkel Wilderness Area and other Class I areas in Colorado. The Division committed in the 2004 LTS SIP amendment to coordinating a monitoring strategy with other agencies and to provide periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. Colorado commits to maintain a monitoring strategy and periodically report to the public and the EPA on an annual basis to include trends, current levels and emission changes. In addition periodic emission inventory updates required by the national emissions reporting rule establish a 3-year reporting cycle for emissions updates. Finally, this RH SIP commits to a five year review process established by the RH rule. Through this, the state believes a demonstration of „before and after emission reductions" will be met.

9.2.1.4 Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance

There are no outstanding certifications of Phase I visibility impairment in Colorado. For Regional Haze, Chapters 6 and 8 specifically delineate the comprehensive BART analysis and Reasonable Progress analysis of other sources. In these sections specific additional controls of selected stationary sources are detailed and emission reductions from these are reflected in the Appendices and technical support documents. The state believes the coordination of these added control measures meets the requirements of the LTS showing both emission limitations and schedules for compliance. In regard to any future certification of any RAVI, the state is prepared to respond to any future certifications as per AQCC Regulation No. 3 X1V.D in accordance with the five year limit established in 40 CFR § 51.306(c).

9.2.1.5 Ongoing Air Pollution Programs

In the 2004 LTS SIP revision, the state committed to:

- Continue to attain and maintain the PM10 and PM2.5 standards which will have some effect on improving visibility in pristine and scenic areas;
- Continue to provide technical support to efforts to understand and reduce the Brown Cloud in the Front Range of Colorado. Analysis of Brown Cloud data indicates it improved approximately 28% between 1991 and 2006, and data through 2009 indicates this trend continues as demonstrated in the APCD Annual Air Quality Data reports;
- Continue to stay involved and inform the Colorado Air Quality Control Commission about emissions growth in the Four Corners area;
- Continue to participate in any future work of the Rocky Mountain National Park research effort; and,
- Continue to administer and follow existing regulations of point, area and mobile sources as specified in AQCC regulations.

9.2.2 Prevention of Future Impairment

The LTS must establish mechanisms to address the prevention of future impairment and outline strategies to ensure progress toward the national goal. The 2004 LTS summarized programs and activities providing reasonable progress toward the national goal under the Phase 1 RAVI program. Generally, Colorado considers its NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities.

9.2.3 Smoke Management Practices

The LTS requires smoke management practices of prescribed burning be addressed. The 2004 LTS described Colorado"s Regulation No. 9 regarding open burning and wildland fire smoke management. As the level and complexity of burning increases the Division committed to continually evaluate its regulatory program for this source of air pollution and surveyed its current activities in the 2004 LTS review. The addition of the Fire Emissions Tracking System (FETS) by the WRAP, FLMs and states allows Colorado to input fire emission data into the national tracking system thereby adding

more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a database of fire related permits and actions - the basis for data entered into the FETS.

9.2.4 Federal Land Manager Consultation and Communication

The state committed to providing for the plans, goals, and comments of the Federal Land Managers during SIP and LTS revisions. The state will provide, at a minimum, the opportunity for consultation with the FLMs at least 60 days prior to any public hearing on any element of the Class I Visibility SIP including LTS revisions and review. In addition the state will publish as part of the SIP process any formal comments received by the FLMs as a result of their review along with a listing of responses the state made in regard to such comments.

9.3 Review of the 2004 RAVI LTS and Revisions

A July 2007 review of the 2004 RAVI LTS concluded that “The Division does not believe extensive and substantive revisions are necessary at this time to ensure reasonable progress toward the national goal under Phase I of the Class I Visibility Protection Program. However, small updates and edits are proposed so this part of the SIP does not become outdated.” Appendix A of this SIP document contains this review. The only other changes to this LTS relate to the change in the update period in Regulation 3, as described above in section 9.2.1, and a commitment to utilize the FETS to track fire data as described above in section 9.2.3. The state commits to work with the FLMs to coordinate any changes to the RH/RAVI LTS on the five year cycle required by the regulation. This will include responding to any notification of impairment by the FLMs, providing an opportunity to comment 60 days prior to any public hearing on proposed changes to the RH/RAVI LTS, and to publish the FLM comments and state responses as part of that review process. Appendix B of this document contains the SIP revision for the RAVI LTS.

9.4 Regional Haze Long Term Strategy

The following presents Colorado"s Long Term Strategy (LTS) for Regional Haze.

9.4.1 Impacts on Other States

Where the state has emissions reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another state or states, the state must consult with the other state(s) in order to develop coordinated emission management strategies. Colorado has analyzed the output of the initial 2006 PSAT product from the WRAP and determined that emissions from the state do not significantly impact other states" Class I areas. The two largest Colorado visibility impacts are at Canyonlands National Park in Utah and Bandelier National Monument in New Mexico, where Colorado"s total nitrate and sulfate contribution are only 1.0% and 0.5%, respectively, of total haze at these Class I areas. This is not a meaningful level of

contribution, and all other modeled contributions at other Class I areas are of a smaller magnitude.

Table 9-1 Colorado's Nitrate and Sulfate Impacts at Bandelier and Canyonlands

Mandatory Class I Area	Modeled Visibility Improvement by 2018 [deciviews]	Colorado's Contribution to 2018 Nitrate	2018 Total Nitrate Impacts at CIA	Colorado's Nitrate Contribution to 2018 Haze at CIA	Colorado's Contribution to 2018 Sulfate	2018 Total Sulfate Impacts at CIA	Colorado's Total Sulfate Contribution to 2018 Haze at CIA	Colorado's Total Nitrate & Sulfate Contribution to 2018 Haze at CIA
Bandelier National Monument	0.3	5.1%	6.6%	0.3%	1.2%	15.5%	0.2%	0.5%
Canyonlands National Park	0.5	6.9%	9.5%	0.7%	2.3%	14.8%	0.3%	1.0%

All Colorado Impacts to nearby Class I Areas that exceed 5.0% are shaded in purple. No Colorado 2018 Sulfate Contributions exceeding 5% were indentified.

9.4.2 Impacts from Other States

Where other states cause or contribute to impairment in a mandatory Class I Federal area, the state must demonstrate it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. Chapter 7 presents modeling information that describes the contribution to visibility impairment in Colorado"s Class I areas from other states. Colorado is establishing reasonable progress goals later in this chapter utilizing modeling results presented in Chapter 7, with supporting information in the technical support documents. This demonstration reflects the emission reductions achieved by the controls committed to by other states.

9.4.3 Document Technical Basis for RPGs

The state must document the technical basis (e.g., modeling) on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area. This is addressed in the Technical Support Document, Chapter 7, and later in this Chapter 9.

9.4.4 Identify Anthropogenic Sources

The state must identify all anthropogenic sources of visibility impairment considered by the state in developing its LTS. Colorado presents comprehensive emission inventories in Chapter 5 and the TSD, and presents emissions control evaluations in Chapters 6 and 8. Chapter 7 and the Technical Support Documents present information about source apportionment for each Class I area in Colorado.

9.4.5 Emission Reductions Due to Ongoing Air Pollution Control Programs

Below is a discussion of ongoing air pollution control programs that reduce visibility impairing emissions throughout Colorado.

Numerous emission reduction programs exist for major and minor industrial sources of NOx, SO2 and particulates throughout the state, as well as in the Denver Metro Area/Northern Front Range region for VOCs, NOx, and particulates from mobile, area, stationary and oil/gas sources, and are contained in the following Colorado Air Quality

Control Commission Regulations:

- Regulation Number 1: Emission Controls for Particulates, Smoke, Carbon Monoxide and Sulfur Oxides
    - In the SIP (includes specific fugitive dust and open burning regulations)
- Regulation Number 3: Stationary Source Permitting and Air Pollutant Emission Notice Requirements
    - Parts A, B,D, F in the SIP or Submitted to EPA for inclusion in the SIP
    - Part C is the Title V program and is delegated by EPA to the state
- Regulation Number 4: New Wood Stoves and the Use of Certain Woodburning Appliances on High Pollution Days
    - Regulation Number 4 is in the SIP. One provision, the Masonry Heater Test Method, is state only. Colorado is waiting for EPA to develop their own test method – the state will adopt it when EPA goes final
- Regulation Number 6: Standards of Performance for New Stationary Sources
    - Part A – Federal NSPS"s adopted by the state – EPA has delegated authority to the state to implement; Colorado has requested delegation for the most recent adoptions
    - Part B – state-only NSPS regulations
- Regulation Number 7: Control of Ozone Precursors
    - The majority of Regulation Number 7 for VOC and NOx control is in the SIP or has been submitted for approval into the SIP – these provisions relate to VOC and NOx control measures for the Denver Metro Area/North Front Range 8-hour ozone nonattainment area and are summarized below
- Regulation Number 9: Open Burning, Prescribed Fire and Permitting – state-only
- Regulation Number 11: Motor Vehicle Emission Inspection Program – Parts A-F in the SIP
- Regulation Number 16: Street Sanding Emissions – In the SIP

Some examples of these programs and the visibility-improving emission reductions they achieve are as follows. It is noted as to whether the program is federally enforceable, submitted by the state in an unrelated submittal for inclusion into the SIP, or state-only enforceable.

- Early reductions from BART sources include approximately 24,000 tpy of SO2 from metro Denver power plants, approximately 6,500 tpy of SO2 from the Comanche power plant, and approximately 18,000 tpy of SO2 from the Craig and Hayden power plants – state-only
- Oil and gas condensate tank control regulations for the Front Range region that have achieved approximately 52,000 tpy of volatile organic compounds (VOC) emission reductions by 2007 - in the SIP - with additional projected reductions of 18,000 tpy by 2010 – Submitted for inclusion in the SIP
- Existing industrial engine control regulations for the Front Range region that have achieved NOx and VOC emissions reductions of approximately 8,900 tpy – In the SIP
- Oil and gas pneumatic actuated device control regulations for the Front Range

region that have achieved VOC emission reductions of approximately 8,400 tpy – state-only

- Mobile source emissions controls for VOCs and NOx through vehicle inspection/maintenance and lower volatility gasoline programs for the Front Range region is estimated to reduce emissions by approximately 8,000 tpy by 2011 – Submitted for inclusion in the SIP
- Statewide condensate tank control regulations that have achieved approximately 5,600 tpy of VOCs emission reductions – state-only
- Statewide existing industrial engine control regulations that are estimated to achieve NOx and VOC emissions reductions of approximately 7,100 tpy by 2010 – state-only
- PM10 emission reduction programs in PM10 maintenance areas throughout the state – In the SIP
- Fugitive dust control programs for construction, mining, vehicular traffic, and industrial sources state-wide – In the SIP
- Smoke management programs for open burning and prescribed fire activities statewide – state-only
- Renewable energy requirements that are driving current and future NOx, SO2 and PM emission reductions from coal-fired power plants - Ballot Initiative 37 – by requiring electricity to be obtained from renewable resources – state-only
- Attaining and maintaining the PM10 and PM2.5 standards throughout the state
- Reducing Colorado Front Range Urban Visibility Impairment (Denver"s Brown Cloud) by 28% between 1991 and 2006) – state-only
- Reducing Colorado emissions in the Four Corners area (which is upwind of numerous Class I areas in three states) through oil and gas control measures administered by the CDPHE and the Colorado Oil and Gas Conservation Commission, and by working with the Southern Ute Indian Tribe to develop a Title V permitting program and a minor source permitting program – state-only
- Federal mobile source tailpipe exhaust reductions of approximately 55,000 tpy of VOC and NOx emissions by 2020 – gained through fleet turn-over

(Discussion of state-only measures in this Regional Haze SIP is informational only and not intended to make such measures federally enforceable. However, such measures could be included in future SIP revisions if found necessary to meet National Ambient Air Quality Standards or visibility requirements.)

Another comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission"s 2008-2009 Report to the Public available at the following website:

http://www.cdphe.state.co.us/ap/rttplinks.html

As recently as 1995 Colorado had 12 “non-attainment” areas within the state for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado"s non-attainment areas also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 1997 8-hour ozone standard, though the nonattainment designation was deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone during the 2005-2007 period put the nine-county Denver region in violation of the 1997 standard, and the deferred nonattainment designation became effective in November 2007. A detailed plan to reduce ozone was adopted by the Colorado Air Quality Control Commission in December 2008 and submitted to EPA for approval in 2009. This new plan contains additional VOC and NOx emission reduction measures to support achievement of compliance with the 1997 ozone standard by the end of 2010.

The table below shows the designation status for all current and former non-attainment areas.

Table 9-1 REDESIGNATION and PLAN AMENDMENT STATUS REPORT

PM10	Redesignations	Plan Amendments
Aspen	AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03	10-year update: AQCC approved 12/16/10
Canon City	AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00	10-year update: AQCC approved 11/20/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
Denver	AQCC approved 4/19/01; EPA approved 9/16/02, effective 10/16/02	Plan amendment developed with MOBILE6 to remove I/M from SIP; AQCC approved 12/15/05; EPA approved 11/6/07, effective 1/7/08
Lamar	AQCC approved 11/15/01; EPA approved 10/25/05, effective 11/25/05	None
Pagosa Springs	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Steamboat Springs	AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04	
Telluride	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010

Carbon Monoxide	**Redesignations**	**Plan Amendments**
Colorado Springs	AQCC approved 1/15/98; EPA approved 8/25/99, effective 9/24/99	- Amendment to drop oxyfuels approved by AQCC 2/17/00; EPA approved 12/22/00, effective 2/20/01 - Amendment using MOBILE6 to eliminate I/M from SIP and revise emission budget approved by AQCC 12/18/03; EPA approved 9/07/04, effective 11/08/04 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Denver	AQCC approved 1/10/00; EPA approved 12/14/01, effective 1/14/02	- Amendment using MOBILE6 to revise emission budgets approved by AQCC 6/19/03; EPA approved 9/16/04, effective 11/15/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08
Ft. Collins	AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03	10-year update: AQCC approved 12/16/10
Greeley	AQCC approved 9/19/96; EPA approved 3/10/99, effective 5/10/99	- Amendment using MOBILE6 to revise emission budget & to eliminate oxyfuels from the regulation/SIP & I/M from the SIP approved by AQCC 12/19/02; EPA approved 8/19/05, effective 9/19/05 - 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010
Longmont	AQCC approved 12/19/97; EPA approved 9/24/99, effective 11/23/99	- Amendment using MOBILE6 to revise emission budget approved by AQCC 12/18/03; EPA approved 9/30/04, effective 11/29/04 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08

Ozone	**Redesignations**	**Plan Amendments**
Denver/Northern Front Range	AQCC approved 1-hour redesignation request and maintenance plan 1/11/01; EPA approved 9/11/01, effective 10/11/01 Early Action Compact 8-hour Ozone Action Plan approved by AQCC 3/12/04; EPA approved 8/19/05, effective 9/19/05	- 8-hour OAP updated to include periodic assessments; AQCC approved 12/15/05; EPA approved //0, effective //0 - 8-hour OAP updated 12/17/06 by AQCC to incorporate Reg. 7"s 75% oil and gas condensate tank requirements. EPA approved 2/13/08, effective 4/14/08 - Due to 2005-2007 ozone values, Front Range has violated the ozone standard and the nonattainment designation became effective 11/20/07; revised attainment plan approved by AQCC 12/11/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009
Lead	**Redesignations**	**Plan Amendments**
Denver	EPA redesignated Denver attainment in 1984	
Nitrogen Dioxide	**Redesignations**	**Plan Amendments**
Denver	EPA redesignated Denver attainment in 1984	

For larger stationary sources, the state of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as being protective of visibility impairment from proposed major stationary sources or major modifications to existing facilities.

9.4.6 Measures to Mitigate the Impacts of Construction Activities

Regulations 1 and 3 are currently part of Colorado"s EPA-approved SIP and apply statewide. In part, provisions of Regulation 1 address emissions of particulate matter, from construction activities. Provisions of Regulation 3 cover issuance of permits applicable to sources defined in these regulations and air pollution emission notices required of specified sources. Provisions of Regulation 1, sections III.D.2.b apply to new and existing point and area sources. This section of the regulation addresses fugitive particulate emissions from construction activities. As such the state believes these regulations address common construction activities including storage and handling of materials, mining, haul roads and trucks, tailings piles and ponds, demolition and blasting activities, sandblasting, and animal confinement operations.

Colorado believes point and area sources of emissions from these regulated sources are in part contributing to regional haze in Colorado. Colorado relies on the particulate emission controls specified in Regulation 1 to most directly address these sources of fine and course particles known to have a minor, but measured, impact on visibility in Class I areas of the state. Based on Coarse Mass Emissions Trace Analysis, described in Section 8 of the Technical Support Document for each Mandatory Class I Federal Area in Colorado included in this SIP, the greatest impact from coarse mass related construction in the state is expected in Rocky Mountain National Park. In RMNP slightly over 6% of the total impact on visibility on the 20% worst days is attributed to coarse mass particulate matter from construction activities. All other Class I areas have impacts from construction in the 2 to 3 percent range.

This regulatory provision requires applicable new and existing sources to limit emissions and implement a fugitive emission control plan. Various factors are specified in the regulation under which consideration in the control plan encompasses economic and technological reasonability of the control.

9.4.7 Smoke Management

For open burning and prescribed fire, Colorado believes its smoke management program reduces smoke emissions through emission reduction techniques and is protective of public health and welfare as well as Class I visibility.

Regulation No. 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement[45]. Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation No. 9 also contains a number of factors the Division must consider in determining whether and, if so, under what conditions, a permit may be granted. Many of these factors relate to potential visibility impacts in Class I areas. A permit is granted only if the Division is reasonably certain that under the permit‟s conditions that include the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. Colorado‟s program also maintains an active compliance assistance and enforcement component. In 2005, the Division certified its smoke management program as consistent with EPA‟s *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998.

Factors considered under Regulation No. 9, include, for example,

- the potential contribution of such burning to air pollution in the area;
- the meteorological conditions on the day or days of the proposed burning;
- the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn;

[45] The Division has determined that agricultural burning is not a significant source of emissions related to regional haze impairment. For example, 2004 estimates from the Division are that only 503 tpy of PM10 were generated from agricultural burning in the entire State of Colorado. See TSD “Agricultural Burning in Colorado, 2003 and 2004 Inventories”.

- whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires:
    - that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas);
    - that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire; and
- a monitoring plan to allow appropriate evaluation of smoke impacts at smoke-sensitive receptors.

The regulation requires all prescribed fire permitees to submit an application to the Division. A permit is granted only if the Division"s assessment demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. The Division reviews each permit application and determines if the burn can be conducted without causing unacceptable visibility impacts within Class I areas, as well as other smoke sensitive sites. In addition, the regulation provides for the Division to impose "permit conditions necessary to ensure that the burn will be conducted so as to minimize the impacts of the fire on visibility and on public health and welfare."

Permitted sources are also required to report actual activity to the Division. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, each year all permitted sources must return their permit forms with information indicating whether or not there was any activity in the area covered by the permit and, if so, how many acres were burned. The Division annually prepares a report on prescribed burning activity and estimated emissions. Reports from 1990 through 2009 are available by contacting the Division.

The regulation requires the draft permit for any proposed prescribed fire rated as having a "high" smoke risk rating be subject to a 30-day public comment period. The notice for the public comment period must contain information relating to the potential air quality and visibility impacts at smoke sensitive receptors, including Class I areas.

The Division"s web site contains information about various aspects of Colorado"s Smoke Management Program, downloadable forms and instructions, and links. It is also used to contain the notices for public comment periods for the draft permits subject to public comment. It is located at: http://www.cdphe.state.co.us/ap/smoke/

The addition of the Fire Emissions Tracking System (FETS) allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a data base of fire related permits and actions - the basis for data entered into the FETS.

9.4.8 Emission Limitations and Schedules for Compliance to Achieve the Reasonable Progress Goal, and Enforceability of Emission Limitations and Control Measures

The emission limitations and compliance schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and Regulation Nos. 3 and 7. Enforceability of the requirements is ensured by codifying these requirements in regulation, inspecting the sources for compliance and initiating enforcement action under EPA-approved compliance regimes, and requiring monitoring, recordkeeping and reporting.

9.4.9 Source Retirement and Replacement Schedules

Source retirement and replacement schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and in Regulation No. 3. Unless otherwise indicated in those chapters or in Regulation No. 3, the state assumes that all other stationary sources will remain in operation through the end of this planning period. For mobile sources, the turnover of the fleet from older, higher-emitting vehicles to newer, lower-emitting vehicles is captured in the emission inventory presented in Chapter 5 – the fleet turn-over rate was developed utilizing EPA-approved methodologies.

9.4.10 Anticipated Net Effect on Visibility

The WRAP has produced extensive analytical results from air quality monitoring, emissions inventories and air quality modeling. These data demonstrate that causes of regional haze in the West are due to emissions from a wide variety of anthropogenic and natural sources, some of which are controllable, some of which are natural, and some of which originate outside the jurisdiction of any state or the federal government and are uncontrollable. Analyses to date consistently show that anthropogenic emissions of haze causing pollutants will decline significantly across the West through 2018, but overall visibility benefits of these reductions will be tempered by emissions from natural, international, and uncontrollable sources.

Colorado in this RH SIP addresses projections to 2018 anticipating growth and all committed to or reasonably expected controls at the time of modeling (emission inventories for Colorado are presented in Chapter 5). Note that at the time of this 2009 WRAP modeling, Colorado had made BART determinations for each subject to BART unit in 2007 and 2008, and the associated emission reductions were included in the modeling. The inventories indicate a total SO2 emission reduction of 58,907 tons per year and a total NOx emission reduction of 123,497 tons per year by 2018. (SO2 and NOx are the primary emissions addressed by Colorado in this Regional Haze SIP.)

For the uniform rate of progress analysis and to establish Reasonable Progress Goal (RPGs), the modeling results from Chapter 7 are utilized. The modeled Uniform Rate of Progress and the progress made towards URP are presented below. Depending on the Class I area, the state has achieved 36 to 76 percent of the visibility improvement necessary to achieve URP. Note that this analysis does not include emission reductions that result from the BART and RP determinations presented in Chapters 6 and 8.

Figure 9-2 Summary of CMAQ Modeling Progress Towards 2018 URP

Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days					20% Best Days		
	Worst Days Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2018 URP delta from Baseline [dv]	2018 Modeling Projection [dv]	CMAQ Modeling % Towards 2018 URP	Best Days Baseline Condition [dv]	2018 CMAQ Modeling Results [dv]	2018 CMAQ Modeling Below Baseline?
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.63	Yes

Uniform Rate of Progress for 2018

Projected Amount of Progress by 2018 Towards URP

The total tons of visibility impairing pollutants reduced by 2018 due to the BART and RP measures adopted in 2010 are summarized below in Figures 9-4, 9-5 and 9-6.

- 2010 BART: 20,734 tons/year
- 2010 BART alternative: 37,488 tons/year
- 2010 RP: 12,624 tons/year

Total: 70,846 tons/year

The following figures also present "CALPUFF" modeling results that show the visibility benefits of each BART and RP determination. Though not additive to the visibility improvement values presented in Figure 9-2 above because different modeling platforms were used, the CALPUFF modeling illustrates that additional visibility improvement can be anticipated from the BART and RP controls.

Figure 9-3 Emission Reductions Achieved by 2010 BART Determinations

BART Emission Control Analysis

NOx BART - SCR

Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Hayden - Unit 2	$ 71,780,853	$ 12,321,491	3,032	$ 4,064	0.82	23 (Zirkel)
Hayden - Unit 1	$ 61,938,167	$ 10,560,612	3,120	$ 3,385	1.12	48 (Zirkel)
Craig - Unit 2 (SCR @ 74% Reduction)	$ 209,552,000	$ 25,036,709	3,975	$ 6,299	0.98	41 (Mt. Zirkel)

NOx BART - SNCR

Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Craig - Unit 1 (SNCR @ 14% reduction)	$ 13,118,000	$ 3,797,000	727	$ 5,226	0.31	15 (Mt. Zirkel)
CEMEX - Kiln	$ 600,000	$ 1,636,636	846	$ 1,934	0.40	14 (RMNP)

NOx BART - Other

Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5 (ULNB w/OFA)	$ 2,895,672	$ 288,844	215	$ 1,342	0.08	> 0 (RMNP)
Drake - Unit 6 (ULNB w/OFA)	$ 3,340,318	$ 337,751	509	$ 664	0.20	> 3 (RMNP)
Drake - Unit 7 (ULNB w/OFA)	$ 4,500,232	$ 461,217	749	$ 616	0.26	> 3 (RMNP)
CENC (TriGen) - Unit 4 LNB, w/SOFA	$ 4,284,900	$ 678,305	214	$ 3,170	0.08	3 (RMNP)
CENC (TriGen) - Unit 5 LNB, w/SOFA and SNCR	$ 6,556,888	$ 1,739,825	354	$ 4,919	0.26	14 (RMNP)
CEMEX - Dryer T5 Permit Limits	$ -	$ -	0	$ -	0.00	none

SO2 BART

Source	Capital or O&M Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Drake - Unit 5: (DSI w/0.26 Emission Limit 30-day)	$ 6,000,000	$ 1,340,663	762	$ 1,761	0.12	2 (RMNP)
Drake - Unit 6: (FGD w/0.13 Emission Limit 30-day)	$ 38,000,000	$ 6,665,771	2,368	$ 2,816	0.24	3 (RMNP)
Drake - Unit 7: (FGD w/0.13 Emission Limit 30-day)	$ 44,166,000	$ 9,577,538	3,764	$ 2,544	0.39	6 (RMNP)
Hayden - Unit 1 Tighten Emission Limit to 0.13	$165,000 parts & $110,000 O&M	$ 141,150	61	$ 2,318	0.01	>12 (Mt. Zirkel)
Hayden - Unit 2 Tighten Emission Limit to 0.13	$165,000 parts & $110,000 O&M	$ 141,150	39	$ 3,629	0.05	>8 (Mt. Zirkel)

TOTAL CAPITAL COST	$ 467,283,031
TOTAL ANNUALIZED COST	$ 74,724,662

TOTAL NOX REDUCED	**13,741**	*tons/year*
TOTAL SO2 REDUCED	**6,993**	*tons/year*
TOTAL COMBINED POLLUTANTS REDUCED	**20,734**	*tons/year*

Figure 9-4 Emission Reductions Achieved by 2010 BART Alternative Determinations

Facility	NOx Emissions Average 2006-2008 (tpy)	NOx Emissions from Alternative (TPY)	Total NOx Emissions Reduced (TPY)	SO2 Emissions Average 2006 -2008 (tpy)	SO2 Emissions from Alternative (TPY)	Total SO2 Emissions Reduced (TPY)
Arapahoe						
Unit 3	1,770	0		925	0	
Unit 4	1,148	900[46]		1,765	1.28	
Cherokee						
Unit 1	1,556	0		2,221	0	
Unit 2	2,895	0		1,888	0	
Unit 3	1,866	0		743	0	
Unit 4	4,274	2,063[47]		2,135	7.81[48]	
Valmont	2,314	0		758	0	
Pawnee	4,538	1,403[49]		13,472	2,406[50]	
Totals	20,361	4,366	15,995	23,908	2,415	21,493

Total Emission Reductions Achieved: 37,488 tons per year

[46] Includes 300 tpy NOx for offset or netting purposes and 600 tpy NOx from firing Arapahoe 4 on natural gas as a peaking unit.

[47] Includes 500 NOx tpy for offset or netting purposes and emissions at 0.12 lb NOx/MMBtu

[48] Emissions at 0.0006 lb SO2/MMBtu

[49] Emissions at 0.07 lb NOx/MMBtu

[50] Emissions at 0.12 lb SO2/MMBtu

Figure 9-5 Emission Reductions Achieved by 2010 RP Determinations

RP Emission Control Analysis

NOx RP - SCR

Source	SCR Capital Costs	Annualized SCR Costs	SCR NOx Reduced [tpy]	SCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement

NOx RP - SNCR

Source	SNCR Capital Costs	Annualized SNCR Costs	SNCR NOx Reduced [tpy]	SNCR NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Craig - Unit 3 (SNCR @ 15% Reduction)	$ 13,139,000	$ 4,173,000	854	$ 4,886	0.32	6 (Mt. Zirkel)
Holcim Cement (establish limit)	not estimated	$ 2,520,000	1,028	$ 2,451	0.23	5 (GSDNP)

NOx RP- Other

Source	Capital Costs	Annualized Costs	NOx Reduced [tpy]	NOx Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	861	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	516	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	624	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Nixon - Unit 1 (ULNB w/Overfire Air)	$ 3,822,000	$ 970,000	707	$ 1,372	0.15	2 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (enchanced combustion control)	$ 1,180,000	$ 288,450	448	$ 644	0.35	18 (RMNP)

SO2 RP

Source	Capital Costs	Annualized Costs	SO2 Reduced [tpy]	SO2 Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	1,457	n/a	n/a	n/a
Cameo - Unit 1 (Shutdown)	n/a	n/a	849	n/a	n/a	n/a
Cameo - Unit 2 (Shutdown)	n/a	n/a	1,769	n/a	n/a	n/a
CENC - Boiler 3 (none)	n/a	n/a	n/a	n/a	n/a	n/a
Craig - Unit 3 (tighten existing emission limit)	none	none	0	n/a	0.26	6 (RMNP)
Holcim Cement (establish limit)	not estimated	not estimated	0	n/a	-	n/a
Nixon - Unit 1 LSD @ 0.10 lb/MMBtu (0.11 lb/MMBtu 30-day rolling)	$ 96,160,000	$ 12,036,604	3,215	$ 3,744	0.46	11 (RMNP)
Nucla (none)	n/a	n/a	n/a	n/a	not modeled	not modeled
Rawhide - Unit 1 (no technically feasible options)	n/a	n/a	n/a	n/a	n/a	n/a

PM RP

Source	Capital or O&M Costs	Annualized Costs	PM Reduced [tpy]	PM Control Cost [$/ton]	CALPUFF Δ dv Improvement	# of Days of Improvement
Black Hills - Clark Units 1 & 2 (shutdown)	n/a	n/a	72	n/a	n/a	n/a
Cameo - Units 1 & 2 (Shutdown)	n/a	n/a	225	n/a	n/a	n/a

TOTAL CAPITAL COST	$ 114,301,000	
TOTAL ANNUALIZED COST	$ 19,988,054	

TOTAL NOX REDUCED	5,038	*tons/year*
TOTAL SO2 REDUCED	7,290	*tons/year*
TOTAL PM REDUCED	297	*tons/year*
TOTAL COMBINED POLLUTANTS REDUCED	12,624	*tons/year*

Of these 70,800 tons of SO2 and NOx reduced due to 2010 BART and RP, approximately 44,500 tons per year were not included in the WRAP"s 2009 "CMAQ" modeling. Figure 9-6 below presents this analysis for each of the BART and RP sources.

Figure 9-6 Difference Between the WRAP and Final BART/RP Emissions for NOx and SO2

Additional NOx and SO2 Reductions

Difference between PRP2018b and Proposed BART/RP

PLANT	PRP 2018b NOx [tpy]	2018 BART/RP NOx [tpy]	Difference [tpy]	PRP 2018b SO2 [tpy]	2018 BART/RP SO2 [tpy]	Difference [tpy]
AQUILA, INC. - W.N. CLARK STATION	1,090	-	(1,090)	1,322	-	(1,322)
CEMEX, INC. - LYONS CEMENT PLANT	901	901	-	97	95	(2)
COLORADO SPRINGS UTILITIES - NIXON PLT	2,331	1,650	(681)	4,073	907	(3,166)
COLORADO SPRINGS UTILITIES - DRAKE PLT	3,669	2,789	(880)	2,701	1,590	(1,111)
HOLCIM (US) INC. PORTLAND PLANT	1,859	2,087	228	393	721	328
PLATTE RIVER POWER AUTHORITY - RAWHIDE	3,912	1,418	(2,494)	927	913	(14)
PUBLIC SERVICE CO - CAMEO (shutdown)	-	-	-	-	-	-
PUBLIC SERVICE CO - ARAPAHOE (Unit 3-Shutdown, Unit 4 NG only)	-	900	900	-	1	1
PUBLIC SERVICE CO - VALMONT	2,279	-	(2,279)	879	-	(879)
PUBLIC SERVICE CO CHEROKEE PLT (Units 3 & 4)	5,998	1,813	(4,185)	5,214	8	(5,206)
PUBLIC SERVICE CO CHEROKEE PLT (Units 1 & 2)	4,317	250	(4,067)	1,750	-	(1,750)
PUBLIC SERVICE CO COMANCHE PLT (Units 1 & 2)	6,143	4,602	(1,541)	3,686	2,953	(733)
PUBLIC SERVICE CO COMANCHE PLT (Unit 3)	2,600	2,600	-	3,250	3,250	-
PUBLIC SERVICE CO HAYDEN PLT	7,307	1,341	(5,966)	2,898	2,541	(357)
PUBLIC SERVICE CO PAWNEE PLT	3,942	1,403	(2,539)	2,225	2,406	181
TRI STATE GENERATION CRAIG (Units 1 & 2)	10,974	5,861	(5,113)	2,117	1,952	(165)
TRI STATE GENERATION CRAIG (Unit 3)	5,825	4,839	(986)	1,823	1,863	40
TRI STATE GENERATION NUCLA	1,753	2,167	414	1,325	1,325	0
TRIGEN - COLORADO ENERGY CORPORATION (Units 4 & 5)	1,185	722	(463)	2,624	2,762	138
TRIGEN - COLORADO ENERGY CORPORATION (Unit 3)	159	222	63	170	379	209
	66,243	**35,565**	**(30,678)**	**37,473**	**23,666**	**(13,807)**

Combined Reductions from NOx and SO2 Controls [tpy]: (44,486)

These substantial additional emission reductions will further the amount of progress achieved by 2018.

Colorado believes the combination of WRAP"s CMAQ modeling and the Division"s BART and RP modeling adequately demonstrate the anticipated net positive visibility benefit or improvement for this SIP. Although the state of Colorado makes no commitment to produce comprehensive RH modeling unless resources are available and there is a need for such analysis (e.g., through the WRAP), it is anticipated in the five year review required by the RH rule and committed to in this SIP that additional regional CMAQ modeling will be done to evaluate compliance with the Reasonable Progress Goals for all the western states.

9.5 Reasonable Progress Goals

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals, for each Class I area in Colorado (expressed in deciviews) that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. The reasonable progress goals (RPGs) must provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

Colorado is relying on the Western Regional Air Partnership"s (WRAP"s) CMAQ regional modeling performed in 2009 to establish these goals. As stated throughout this chapter,

all western states' reasonably foreseeable control measures at the time of modeling were included in the projections of 2018 visibility levels. Colorado determines that the 2018 projections represent significant visibility improvement and reasonable progress upon the state's consideration of the statutory factors, and are the RPGs for each Class I area. Figure 9-7 presents these RPGs.

Figure 9-7 Reasonable Progress Goals for Each Class I Area

Colorado Mandatory Class I Federal Areas

Uniform Progress Summary in Haze Index Metric

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	*20% Worst Days*					*20% Best Days*		
	Worst Days Baseline Condition [dv]	*Uniform Rate of Progress at 2018 [dv]*	*2018 URP delta from Baseline [dv]*	*2018 Modeling Projection [dv]*	*CMAQ Modeling % Towards 2018 URP*	*Best Days Baseline Condition [dv]*	*2018 CMAQ Modeling Results [dv]*	*2018 CMAQ Modeling Below Baseline?*
Great Sand Dunes National Park & Preserve	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
Mesa Verde National Park	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
Rocky Mountain National Park	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	0.83	8.98	75.9%	0.70	0.53	Yes

Reasonable Progress Goals for 2018

No Degradation of Visibility for the Best Days

As required, each Class I area must 1) make improvement in visibility for the most-impaired (20% worst) days over the period ending in 2018, and 2) allow no degradation in visibility for the least-impaired (20% best) days. This is demonstrated in Figure 9-5. As stated above in section 9.4.10, these goals reflect the emissions reductions achieved throughout Colorado (as reflected in the Chapter 5 inventories) and the nation. The additional emissions reductions from the BART and RP determinations will increase the amount of progress achieved by 2018.

In establishing the RPGs, the state considered the required four factors as per EPA regulations: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. Colorado describes in Chapter 8 how the four factors were used to select significant sources/source categories not already covered by BART or federal measures for control evaluation. The evaluations resulted

in substantial emission reductions that build on the reductions already achieved by other measures.

Although the state used the four factors to determine reasonable and appropriate emission controls for subject facilities, Figure 9-7 illustrates that the RPGs do not achieve URP. The state realizes additional emissions reductions from both within and outside of the state are necessary to achieve URP. The state finds that the RPGs established in this SIP are reasonable for this planning period and that achieving URP in this planning period is not reasonable. In this SIP, Colorado has described, based upon its consideration of the statutory factors, why certain controls for specified BART and RP sources are reasonable, and why additional controls during this planning period are not reasonable. Similarly, the state has described why additional controls for certain area sources (such as oil and gas heater treaters and lean burn RICE engines) are not reasonable in this planning period. The emission reductions needed to achieve URP at each Class I area for this planning period cannot be determined with precision, due to limitations in calculating and modeling all of the visibility-impairing emissions. In the first 5-year assessment, the state commits to begin evaluating this shortfall, first accounting for the degree of additional emission reductions achieved in Colorado and in other states that are not included in the modeling, and then assessing the inventory and modeling technical issues.

Because RPGs are not achieving URP by 2018 and natural conditions by 2064, Colorado is required by the Regional Haze rule to re-calculate and state the length of time necessary to achieve natural conditions, as shown below and presented in Figure 9-8. Instead of achieving natural conditions in 2064 (60 years) at all Class I areas, the year and the length of time is re-calculated as follows:

- Sand Dunes: 2152 (148 years)
- Mesa Verde: 2168 (164 years)
- Zirkel & Rawah: 2106 (102 years)
- Rocky Mountain: 2098 (94 years)
- Black Canyon, Weminuche, & La Garita: 2119 (115 years)
- Eagles Nest, Flat Tops, Maroon Bells & West Elk: 2083 (79 years)

The recalculated natural conditions timeline is based upon progress through 2018, though, as described above, the calculations do not consider the emission control requirements adopted by the state in 2010 and presented in Chapters 6 and 8. The four factors were used to evaluate significant sources of SO2, NOx (and PM from stationary sources) only as the state also determined that it was not reasonable to evaluate sources organic carbon, elemental carbon and particulate matter for control during this planning period. Thus, all reasonable control measures are presented in this SIP and it is acceptable under the Regional Haze rule that natural conditions are projected to be achieved beyond 2064.

Figure 9-8 Re-Calculation of the Length of Time Necessary to Achieve Natural Conditions

Colorado Mandatory Class I Federal Areas

Number of Years to Attain Natural Conditions

Based on WRAP CMAQ Modeling using the PRP 2018b

Mandatory Class I Federal Area	20% Worst Days										
	Baseline Condition [dv]	Uniform Rate of Progress at 2018 [dv]	2064 Natural Conditions [dv]	Total Haze Delta (Baseline-2064 NC) [dv]	Haze Program Period [yrs]	Haze Program Reduction Rate [dv/yr]	2018 Modeling Projection [dv]	2018 Modeling <= 2018 UPG?	Recast Reduction Rate [dv/yr]	Number of years to NC [yrs]	New NC Goal [year]
Great Sand Dunes National Park & Preserve	12.78	11.35	6.66	6.12	60	0.102	12.20	No	0.041	148	2152
Mesa Verde National Park	13.03	11.58	6.81	6.22	60	0.104	12.50	No	0.038	164	2168
Mount Zirkel & Rawah Wilderness Areas	10.52	9.48	6.08	4.44	60	0.074	9.91	No	0.044	102	2106
Rocky Mountain National Park	13.83	12.27	7.15	6.68	60	0.111	12.83	No	0.071	94	2098
Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas	10.33	9.37	6.21	4.12	60	0.069	9.83	No	0.036	115	2119
Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas	9.61	8.78	6.06	3.55	60	0.059	8.98	No	0.045	79	2083

The following figures for Mesa Verde National Park illustrate the re-calculations.

Figure 9-9 Current Uniform Rate of Progress Glidepath for Mesa Verde and the Reasonable Progress Goal for 2018

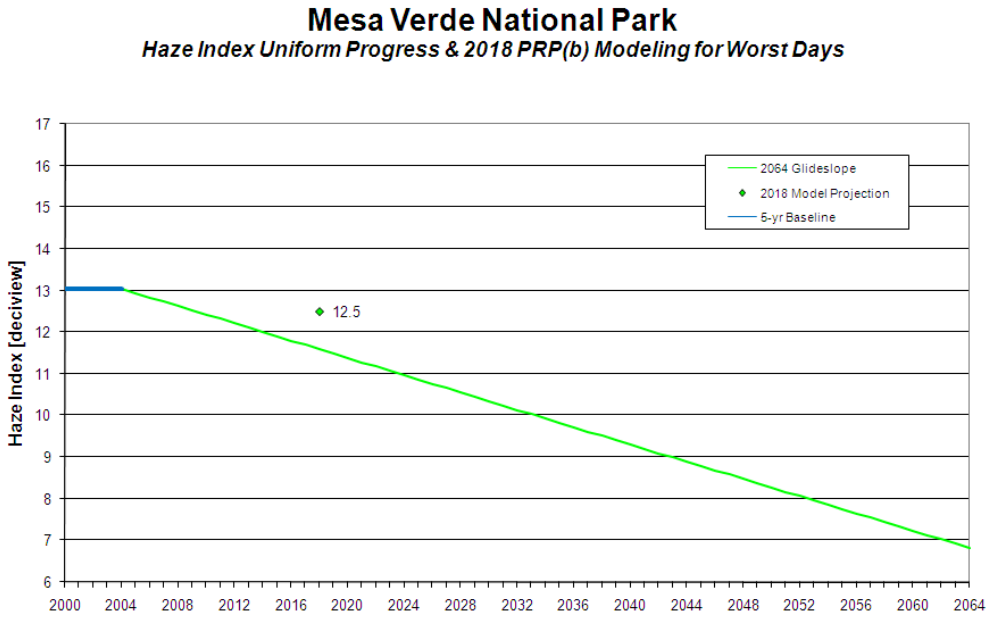
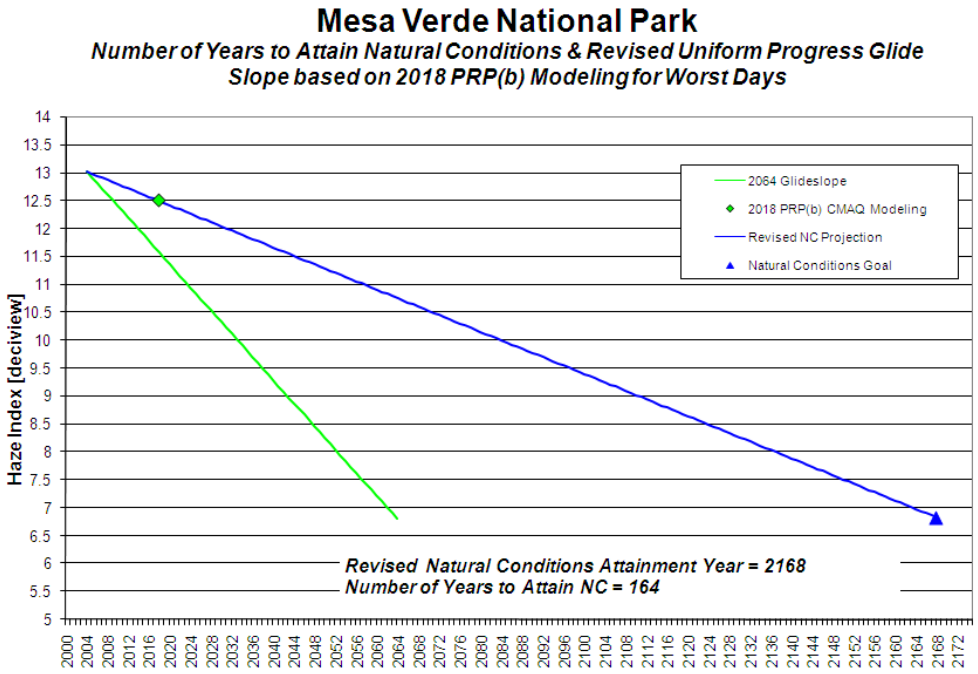


Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions



Chapter 10 Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

10.1 Future Consultation Commitments

10.1.1 FLM Consultation

As required by 40 CFR 51.308(i)(4), Colorado will continue to consult with the FLM on the implementation of the visibility protection program: and the following items

1. Colorado will provide the FLM an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I visibility impairment. This report will include:
    a. Implementation of emission reduction strategies identified in the SIP as contributing to achieving improvement of worst-day visibility;
    b. Summary of major new source permits issued;
    c. Any changes to the monitoring strategy or monitoring stations that may affect tracking reasonable progress;
    d. Work underway in preparing the five and ten year reviews
2. Colorado will afford the FLM with an opportunity for consultation in person and at least 60 days prior to holding any public hearing on a SIP revision. The FLM consultation must include the opportunity to discuss their assessment of visibility impairment in each federal Class I area; and to provide recommendations on the reasonable progress goals and on the development and implementation of the visibility control strategies. Colorado will include a summary of how it addressed the FLM comments in the revised RH SIP.

10.1.2 Tribal Consultation

Colorado will continue to remain in contact with those Tribes which may reasonably be anticipated to cause or contribute to visibility impairment in Colorado mandatory Class I Federal area(s). For those Tribes that adopted a RH TIP, Colorado will consult with them directly. For those Tribes without a RH TIP, Colorado will consult with both the Tribe and EPA. Documentation of the consultation will be maintained.

10.1.3 Inter-state Consultation/Coordination

In accordance with 40 CFR 51.308(d)(1)(iv) and 51.308(d)(3)(i), Colorado commits to continue consultation with Arizona, Nebraska, Kansas, Wyoming, New Mexico, Utah, and California, and any other state which may reasonably be anticipated to cause or contribute to visibility impairment in federal Class I areas located within Colorado. Colorado will also continue consultation with any state for which Colorado"s emissions may reasonable be anticipated to cause or contribute to visibility impairment in those state"s federal Class I areas.

With regards to the established or updated goal for reasonable progress, should disagreement arise between another state or group of states, Colorado will describe the actions taken to resolve the disagreement in future RH SIP revisions for EPA‟s consideration. With regards to assessing or updating long-term strategies, Colorado commits to coordinate its emission management strategies with affected states and will continue to include in its future RH SIP revisions all measures necessary to obtain its share of emissions reductions for meeting progress goals.

10.1.4 Regional Planning Coordination

As per the requirements of [51.308(c)(1)(i)],Colorado commits to continued participation with one or more other States in a planning process for the development of future RH SIP revisions. Future plans will include:

1. Showing of inter-state visibility impairment in federal Class I areas based on available inventory, monitoring, or modeling information as per the requirements of [51.308(c)(1)(ii)].
2. Description of the regional planning process, including the list of states, which have agreed to work with Colorado to address regional haze, the goals, objectives, management, decision making structure for the regional planning group, deadlines for completing significant technical analyses and developing emission management strategies, and a schedule for State review and adoption of regulations implementing the recommendations of the regional group as per the requirements of ; [51.308(c)(1)(iii)].
4. Address fully the recommendations of WRAP, including Colorado‟s apportionment of emission reduction obligations as agreed upon through WRAP and the resulting control measures required [51.308(c)(1)(iv) and 51.308(d)(3)(ii)].

10.2 Commitment to Progress Reports

40 CFR 51.308(g), requires a State/Tribe to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goal(s). The first progress report is due five years from the submittal of the initial implementation plan and must be in the form of an implementation plan revision that complies with Sections 51.102 and 51.103. At a minimum, the progress reports must contain the elements in paragraphs 51.308(g)(1) through (7) for each Class I area as summarized below.

1. Status of implementation of the RFP SIP measures for CIAs in Colorado and those outside the State identified as being impacted by emissions from within the state
2. Summary of emissions reductions in Colorado adopted or identified as part of the RFP strategy

3. A five year annual average assessment of the most and least impaired days for each CIA in Colorado including the current visibility conditions, difference between current conditions and baseline and change in visibility impairment over the five year period
4. Analysis, by type of source or activity of pollutant emission changes or activities over the five year period from all sources contributing to visibility impairment in Colorado, based on the most recent EI with estimates projected forward as necessary to account for changes in the applicable five year period
5. Assessment of significant changes in anthropogenic emissions in or out of Colorado in the applicable five years which limited or impeded RFP;
6. Assessment of the current SIP sufficiency to meet reasonable progress goals both in Colorado and other States CIA identified as being significantly impacted by Colorado emissions
7. Assessment of Colorado"s visibility monitoring strategy and modifications of the strategy as necessary.

In accordance with the requirements listed in Section 51.308(g) of the federal regional haze rule, Colorado commits to submitting a report on reasonable progress to EPA every five years following the initial submittal of the SIP. That report will be in the form of an implementation plan revision. The reasonable progress report will evaluate the progress made towards the reasonable progress goal for each mandatory Class I area located within Colorado and in each mandatory Class I area located outside Colorado, which have been identified as being affected by emissions from Colorado.

The State will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

10.3 Determination of Current Plan Adequacy

Based on the findings of the five-year progress report, 40 CFR 51.308(h) requires a State to make a determination of adequacy of the current implementation plan. The State must take one or more of the actions listed in 40 CFR 51. 308(h)(1) through (4) that are applicable. These actions are described below and must be taken at the same time the State is required to submit a five-year progress report.

1. If the State finds that no substantive SIP revisions are required to meet established visibility goals and emissions reductions, the State will provide a negative declaration that no implementation plan revision is needed.
2. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from outside the State, the State shall notify EPA and the other contributing state(s) or tribe(s). The plan deficiency shall be addressed through a regional planning process in developing additional strategies with the planning efforts described in the progress report(s).
3. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from another country, the State shall notify EPA and provide the available supporting information.

4. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from within the State, the State shall revise the plan to address the deficiency within a year.

Colorado commits, in accordance with 40 CFR 51.308(h), to make an adequacy determination of the current SIP at the same time a five-year progress report is due.

10.4 Commitment to Comprehensive SIP Revisions

In addition to SIP revisions made for plan adequacy as specified in Section 10.3 of this plan, 40 CFR 51.308(f)(1-3)requires a State to revise and submit its regional haze implementation plan to EPA by July 31, 2018, and every ten years thereafter. Colorado commits to providing this revision and to evaluate and reassess elements under 40 CFR 51.308(d) taking into account improvements in monitoring data collection and analysis, and control technologies. Elements of the future plans are summarized below.

10.4.1 Current Visibility Conditions

Colorado commits to determine and report current visibility conditions for the most and least impaired days using themost recent five year period for which data is available and to determine the actual progress made towards natural conditions. Current visibility conditions will be calculated based on the annual average level of visibility impairment.

10.4.2 Long Term Strategy Effectiveness

Colorado commits to determine the effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s) and to affirm or revise the RPG and monitoring strategy as specified in 10.4.3 and 10.4.4 of this section.

10.4.3 Affirmation of or Revisions to Reasonable Progress Goals

As part of this comprehensive SIP update and future ten year revisions, Colorado commits to affirm or revise the reasonable progress goals in accordance with the procedures set forth in 40 CFR 51.308(d)(1). For any goal which provided a slower rate of progress than needed to attain natural conditions by the year 2064, Colorado will perform the analysis of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the initial implementation plan. This analysis of additional measures will be performed in accordance with the procedures set forth in 40 CFR 51.308(d)(1)(A) to include a consideration of the costs of compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and a demonstration showing how these factors were taken into consideration in selecting the goal.

1. Colorado commits, in accordance with 40 CFR 51.308(d)(1)(B), to analyze and determine the rate of progress needed to attain natural conditions by the year 2064 comparing baseline visibility to natural visibility conditions in each CIA considering the uniform rate of improvement and emission reduction measures needed to achieve RFP.

2. As per 40 CFR 51.308(d)(1)(B)(ii) if Colorado establishes a RPG with a slower rate of progress than needed to attain natural conditions by 2064, Colorado will demonstrate, based on the factors listed in this section 10.4.3, the rate of progress is unreasonable and the established goal is reasonable. Colorado will provide for a public review, as part of the implementation plan revision in 2018, an assessment of the number of years it will take to attain natural conditions based on the RPG.
3. As per 40 CFR 51.308(d)(1(B)(iv) Colorado will consult with States reasonably anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal areas and where Colorado or another State cannot agree a RPG is appropriate, Colorado will describe, in the SIP submittal of 2018, actions taken to resolve disagreements.

Chapter 11 Resource and Reference Documents

There are a substantial number of documents that are referenced in this SIP and form the detailed technical basis for the proceeding Chapters. This Chapter is not the full Technical Support Document. It is a catalog of references used in the preparation of this SIP revision. The full Technical Support Document will be on the Air Pollution Control Division web site at http://www.cdphe.state.co.us/ap/regionalhaze.html

11.1 Class I Area Technical Support Documents (TSDs) TSDs are a comprehensive technical summary for each Class I area in Colorado. The individual Class I area TSDs includes sections describing the Class I area; visibility monitoring; visibility conditions; haze impacting particles; emission source characterization; regional modeling; and PM source apportionment. Included in each TSD is the PSAT Modeling showing estimated source category impacts on Class I areas. Titles include:

Colorado State Implementation Plan for Regional Haze Technical Support Document – Black Canyon of the Gunnison National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Eagles Nest Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Flat Tops Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –La Garita Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document – Maroon Bells Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Mesa Verde National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Mount Zirkel Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Rocky Mountain National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Rawah Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Sand Dunes National Park, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document – Weminuche Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –West Elk Wilderness Area, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

11.2 Other Technical Support Documents In addition to the Class I area-specific TSDs, two other technical support documents have been developed. One for the IMPROVE look-alike monitors at Douglas Pass and Ripple Creek and another for agricultural burning in Colorado. Titles are:

Colorado State Implementation Plan for Regional Haze Technical Support Document –Douglas Pass and Ripple Creek Pass Sites, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, June 2007

Colorado State Implementation Plan for Regional Haze Technical Support Document –Agricultural Burning in Colorado 2003-4 Inventory, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, July 2007

Colorado State Implementation Plan for Regional Haze. Technical Support Document, Analysis of Colorado Visibility Impacts on Nearby Class I Areas, Colorado Dept. of Public Health and Environment, Air Pollution Control Division, March 2007

11.3 Long-Term Strategy Review Update In 2004, the State adopted this SIP revision in order to update the LTS. This SIP revision is intended to amend the 2002 LTS portion of the Class I Visibility SIP. This document is titled:

Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part II Revision of the Long-Term Strategy, Colorado Department of Public Health and Environment, Air Pollution Control Division, November 2004

List of Appendices –

Appendix A – Periodic Review of Colorado RAVI Long Term Strategy

Appendix B – SIP Revision for RAVI Long Term Strategy

Appendix C – Technical Support for the BART Determinations

Appendix D – Technical Support for the Reasonable Progress Determinations

BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION

PACIFICORP'S REBUTTAL STATEMENT

REGARDING PROPOSED REVISIONS TO COLORADO'S STATE IMPLEMENTATION PLAN FOR REGIONAL HAZE AND REGULATION NO. 3, BEST AVAILABLE RETROFIT TECHNOLOGY REQUIREMENTS

I. INTRODUCTION

Pursuant to the schedule set forth by the Colorado Air Quality Control Commission ("AQCC"), PacifiCorp hereby submits this Rebuttal Statement. This Rebuttal Statement is limited to the issues raised by the United States Environmental Protection Agency's ("EPA") October 26, 2010 BART comment letter and the Coalition of Environmental Organizations' Pre-Hearing Statement in this matter, specifically as they relate to the BART determinations for Unit 1 and Unit 2 of the Hayden Generating Station ("Hayden"), and also as they relate generally to Unit 1 and Unit 2 of the Craig Generating Station ("Craig").

At this date appointed for Rebuttal statements, however, PacifiCorp is unable to rebut any position taken by the Colorado Department of Public Health and Environment, Air Pollution Control Division (the "Division") in regard to issues raised by PacifiCorp. This is because – contrary to the schedule set by the AQCC and prejudicially to PacifiCorp - the Division failed in its Pre-Hearing Statement to address any of the arguments raised by PacifiCorp. Instead, the Division noted it would "respond to PacifiCorp's more specific concerns in its Rebuttal." Division Pre-Hearing Statement, page 2. Now that the AQCC has extended the time for the Division to file its Rebuttal Statement to be simultaneous with the filing by PacifiCorp and the other parties, it is impossible for PacifiCorp to rebut the Division's arguments in the same manner all of the other parties are allowed to rebut all of the other arguments. Although this may be an unintended consequence of the fast-track nature of this proceeding, it is a detrimental consequence to PacifiCorp nonetheless and is another reason why the AQCC should "slow down" this highly complex and extremely important rulemaking, and conduct this proceeding along a more reasonable time frame.

Also, to the extent applicable to PacifiCorp's interests in the Hayden and Craig plants, and to the extent consistent with PacifiCorp's position in this proceeding, PacifiCorp incorporates the pertinent portions of the Rebuttals filed by Tri-State Generation and Transmission Association, Inc. ("Tri-State"), Salt River Project Agricultural Improvement and Power District's ("SRP"), and the Public Service of Colorado ("PSCo").

II. SPECIFIC STATEMENT OF FACTUAL AND LEGAL ISSUES ON REBUTTAL

1. The EPA improperly, selectively employs Appendix Y.

On page 2 of its October 26, 2010 comments to Colorado's Regional Haze State Implementation Plan ("EPA BART Comment Letter"), EPA complements the Division's use of "methods and procedures established by the Division for modeling BART sources" because they are "consistent with Appendix Y." However, the EPA then ignores the Division's utter failure to use Appendix Y of 40 C.F.R. Part 51, including its presumptive limits and guideposts regarding cost-effectiveness, when establishing the BART NOx rates for the Hayden power plant. EPA's analysis, like the Division's, ignores the applicable and well-reasoned guidance found in Appendix Y. Even though the Division and EPA seem determined to run away from this critical BART guidance, the AQCC should not allow that to happen. As described in PacifiCorp's Pre-Hearing Statement, EPA promulgated Appendix Y to address BART determinations at coal-fired electrical generating units, the exact issue currently before the AQCC. The Division should follow all of Appendix Y, not just those parts the Division believes is convenient to its most recent BART proposals. The AQCC embraced Appendix Y in its prior BART determinations and should continue to do so now.

2. EPA agrees that the Division did not properly analyze "non-air quality" environmental impacts.

On page 3 of the EPA's BART Comment Letter, EPA stated that the "non-air quality impacts in the SIP and five factor analysis for each control measure are inconsistent." PacifiCorp agrees, and argued as much in its Pre-Hearing Statement. PacifiCorp Pre-Hearing Statement, Section 3.C. The AQCC should send the Hayden BART determination back to the Division for an appropriate consideration and analysis of this factor.

3. The AQCC should not consider "air quality" impacts outside of visibility, nor allow them to be addressed at the hearing.

As the EPA states on page 3 of its BART Comment Letter, in regard to BART element number 2, the Division should "not include air quality impacts" in its discussion of "non air quality" impacts from the proposed BART controls. While this conclusion seems self-evident, the Coalition argues to the contrary in its Pre-Hearing Statement that many "air quality impacts," such as ozone, PM2.5, etc., should be considered in the November 18th hearing. Coalition Pre-Hearing Statement, pages 3-6, 10 – 11. The Coalition's position clearly ignores the plain language of the law, which requires an analysis only of "non-air quality" impacts from the BART controls considered. The Coalition fails to cite any authority in its Pre-Hearing Statement that shows ozone, PM2.5, or nitrogen deposition from combusting coal must be considered in the BART determination process.

The entire point of the "non-air quality" impacts analysis for BART is to analyze the potential impacts from installing the particular type of BART pollution control technology, not to analyze the impacts of combusting coal to create electricity. As EPA explained in Appendix Y, when analyzing the "non-air quality" impacts a party should "address environmental impacts other than air quality due to the emissions of the pollutants in question." Appendix Y,

IV.D.4.i.1. (emphasis added). The Coalition's argument completely misses the mark. It focuses on the effectiveness of the BART pollution control technology in reducing the effects of combusting coal and ignores the independent environmental issues concerned with the particular BART control technology being reviewed.

Additionally, as stated in the November 3, 2010 Joint Motion to Strike filed by PacifiCorp and others, air quality-related health impacts should not be considered as part of the five-factor BART test and should not be part of the BART rulemaking hearing. While the AQCC ruled on November 10, 2010 that nothing bars the admission of the health-related information and, therefore the AQCC will allow the information at the hearing, PacifiCorp respectfully disagrees and believes that the AQCC is inviting reversible error by allowing evidence outside of the BART five-factor test to be included in a hearing on BART determinations. Moreover, the AQCC should not, as it has, severely limit the time and opportunities for the parties to present relevant information and argument during the upcoming hearing, while at the same time allowing irrelevant information to take up large blocks of time and play any role.

4. EPA also finds problems with the Division's method of selecting BART NOx control.

In the EPA Comment Letter, EPA stated that "aspects of the State's criteria for selecting NOx controls are very concerning." *Id.* at 3. PacifiCorp agrees, and argued as much throughout its Pre-Hearing Statement. EPA further explained that it could find "no rational basis for establishing benchmarks for post-combustion controls but not for any other types of NOx controls." *Id.* Again, PacifiCorp agrees. The Division's selection of the "cost-effectiveness" and "visibility improvement" thresholds for SCR and SNCR is arbitrary and capricious, particularly because the Division also ignores establishing thresholds for low NOx burners ("LNBs"), over-fire air ("OFA"), and other combustion controls. Why should one form of NOx control be subject to a different test and justification than another source of NOx control? How can the Division adequately compare NOx control alternatives when it uses different metrics to analyze those controls? The Division's BART proposals do not answer any of these important questions. Its analysis of BART NOx controls is flawed and should be rejected.

5. The Coalition's "Baseline Emissions" analysis is flawed.

The Coalition argues in its Pre-Hearing Statement that the Division erred by relying on "average actual emissions from each source from the years 2006 to 2008," and claims that PTE should be used instead. *Id.* at 11 - 12. This is directly contrary to Appendix Y, which states that "baseline emissions rate should represent a realistic depiction of anticipated annual emissions from the source." Appendix Y, IV.D.4.d.1. (emphasis added). Appendix Y further explains that "for existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions for a baseline period." *Id.* (emphasis added). Because a source's PTE assumes full-time (24/7/365) operation at full capacity, it is not a "realistic depiction" of a source's emissions (which are effected by plant shutdowns and curtailments). Therefore, the Coalition's BART NOx control analysis is flawed because it relies upon the improper Baseline Emissions data.

6. The AQCC should not consider visibility impacts at multiple Class I areas.

The Coalition argues that the Division erred by only considering visibility impairment at the most-impacted Class I area, and not at every impacted Class I area. Coalition Pre-Hearing Statement, page 15. The Coalition's argument ignores the plain, applicable guidance in Appendix Y.

Appendix Y states that the BART determination should include an "appropriate dispersion model to determine the visibility improvement expected at a Class I area from the potential BART control technology." Appendix Y, IV.D.5. (emphasis added). The guidance also states that while you may model receptors at different Class I areas, this is done to determine "whether the effects at those areas may be greater than at the nearest Class I area." *Id.* Finally, Appendix Y states that if "the highest modeled effects are observed at the nearest Class I area, you may choose not to analyze the other Class I areas any further as additional analyses might be unwarranted." *Id.* (emphasis added). All of these statements individually and combined make clear that the Division has the authority to analyze the most effected Class I area, but not multiple areas. In addition, nothing in Appendix Y suggests that visibility impacts to multiple Class I areas should be considered. The Coalition's arguments to the contrary are just wrong.

7. The AQCC should not consider "Plant-Wide Impacts."

Again, the Coalition is asking the AQCC to sail uncharted waters. The Coalition, without citing any authority for the proposition, claims that the AQCC should consider "the impacts that all BART eligible sources at a facility will have on regional haze" when determining BART. Coalition Pre-Hearing Statement, pg. 16. However, Appendix Y clearly states that "for each affected emission unit you must establish BART for that pollutant." Appendix Y, IV.B. (emphasis added). BART is not established on a plant-wide basis as the Coalition suggests, but on a unit-by-unit basis.

8. The information the Coalition provided regarding NOx controls in excess of $5,000 per ton is not relevant.

The Coalition incorrectly mixes and matches air quality programs to make the argument that costs in excess of $5,000 per ton of NOx removed should be considered. The Coalition does this by citing cost per ton dollar amounts from inapplicable sources, such as from EPA settlements regarding NSR issues, BACT determinations for new coal-fired plants, and notes from meetings regarding petroleum refinery changes. The AQCC should not rely on this suspect data because it has no relevance in this proceeding.

III. PROCEDURAL ISSUES

PaciCorp renews its objection to the compressed schedule for this rulemaking and notes again the negative impact the compressed schedule has on PacifiCorp's ability to fully present its positions, which includes limiting the witnesses PacifiCorp can call and stifling the cross-examination of the Division's and Coalition's witnesses.

Respectfully submitted this 11th day of November.

By___/s/ Katheryn J. Coggon_____

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CERTIFICATE OF SERVICE

I hereby certify that on November 11, 2010, undersigned served a copy of the foregoing **PACIFICORP'S REBUTTAL STATEMENT** on the following by:

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NOTE TO THE PARTIES: Email service between the parties for prehearing statements and any other materials to be filed with the Commission Office is allowed. Please be sure that all parties are copied on the emails.		
Party Status Statements due to the Commission Office, Attorney General's Office, Division Office	September 20, 2010 at 5:00 p.m.	4300 Cherry Creek Drive South EDO-AQCC-A5 Denver, CO 80246
Status Conference	September 27, 2010 at 2:00 p.m.	4300 Cherry Creek Drive South Building C, Conference Room C1E
Final Prehearing Statement due to the Commission Office and everyone listed on the Party Status List	October 27, 2010 at 5:00 p.m.	4300 Cherry Creek Drive South EDO-AQCC-A5 Denver, CO 80246
Pre-Hearing Conference	November 1, 2010 at 1:00 p.m.	4300 Cherry Creek Drive South Building C, Conference Room C1E
Rebuttal Statements due to the Commission Office and everyone listed on the Party Status List	November 8, 2010 at 5:00 p.m.	4300 Cherry Creek Drive South EDO-AQCC-A5 Denver, CO 80246
Rulemaking Hearing Date	November 18, 2010 at 9:00 a.m.	4300 Cherry Creek Drive South Building A, Sabin Conference Room
CERTIFICATE OF SERVICE		
I do certify that a true and exact copy of the Party Status List for the upcoming Rulemaking Hearing regarding proposed revisions to the Regional Haze SIP and Regulation Number 3, Part F was emailed to the following on September 21, 2010		
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/s/ Karen Olsten

BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION

PACIFICORP'S PREHEARING STATEMENT

REGARDING PROPOSED REVISIONS TO COLORADO'S STATE IMPLEMENTATION PLAN FOR REGIONAL HAZE AND REGULATION NO. 3, BEST AVAILABLE RETROFIT TECHNOLOGY REQUIREMENTS

I. EXECUTIVE SUMMARY

On August 26, 2010, the Colorado Department of Public Health and Environment, Air Pollution Control Division (the "Division") provided notice of a public rulemaking hearing ("Notice") regarding proposed revisions to both Chapter 6 of the Regional Haze element of the State Implementation Plan (RH SIP) and Regulation 3, Part F, concerning Best Available Retrofit Technology ("BART") rules. PacifiCorp, a regional electric utility with operations in several western states, including ownership of approximately 25% of Unit 1 and approximately 13% of Unit 2 at the Hayden Generating Station, was granted party status[1] in this proceeding. The Notice required parties, such as PacifiCorp, to provide a preliminary prehearing statement by October 27, 2010. These comments are submitted to the Colorado Air Quality Control Commission ("AQCC") in accordance with that requirement and with AQCC Procedural Rule 1.5.5.(5)(c). PacifiCorp's comments specifically concern the BART determinations for Unit 1 and Unit 2 of the Hayden Generating Station ("Hayden"), and also generally apply to Unit 1 and Unit 2 of the Craig Generating Station ("Craig").

PacifiCorp specifically comments as follows: 1) the Division's proposed revisions improperly ignore and wrongly minimize the only applicable BART guidance (issued by EPA and contained in the United States' Code of Federal Regulations) known as "Appendix Y," and its presumptive NOx emissions limits; 2) the Division's imposition of post-combustion NOx control is contrary to federal BART guidance; 3) the Division improperly analyzed the criteria (including cost-effectiveness, visibility improvement levels, non-air quality environmental impacts, etc.) for assessing the use of post-combustion NOx control technologies; 4) the Division's "new" NOx BART determination for Hayden is inconsistent with its previous BART determination, reflecting an arbitrary act by the Division; and 5) the Division's CALPUFF modeling used to determine the projected visibility improvement associated with control technologies for NOx greatly overestimates NOx impacts and leads to an improper and unsupportable BART determination at Hayden Units 1 and 2.

[1] PacifiCorp also owns approximately 19% of Units 1 and 2 at the Craig Generating Station which is a part of the related BART rulemaking set for hearing in December.

PacifiCorp also incorporates the following arguments from other parties' Prehearing Statements: (1) arguments made by Tri-State Generation and Transmission Association, Inc. ("Tri-State") regarding the Hayden and Craig NOx BART determinations and the need for an adjudication of these issues; (2) all of the Salt River Project Agricultural Improvement and Power District's ("SRP") arguments contained in its Prehearing Statement; and (3) Public Service of Colorado's ("PSCo") arguments regarding the overestimation of modeled visibility improvements, the underestimation of the costs of compliance, and that Colorado not require additional controls during the first regional haze planning period. PacifiCorp reserves the right to further address these comments, or to address or incorporate the arguments made by other parties in their Prehearing Statements, during the rebuttal period.

PacifiCorp anticipates it will need one hour for its presentation, including the calling of its witnesses. PacifiCorp's witnesses include: William K. Lawson, Director Environmental Services, PacifiCorp Energy, who will testify regarding the Division's improper application of the cost-effectiveness and visibility improvement criteria; and Cathy S. Woollums, Senior Vice President, Environmental, and Chief Environmental Counsel of MidAmerican Holdings Company, who will testify regarding the Division's cost-effectiveness threshold. Legal counsel for PacifiCorp, including Mike Jenkins, Blaine Rawson, or Katheryn Coggon, may present legal arguments and comments at the hearing also.

II. SPECIFIC STATEMENT OF FACTUAL AND LEGAL ISSUES

1. The Division ignored the only applicable BART guidance, Appendix Y, and Appendix Y's presumptive BART limits, in establishing BART for Hayden.

EPA's formal guidance on BART determinations for electrical generating units ("EGUs"), Appendix Y of 40 C.F.R. Part 51, contains a detailed explanation of the five-factor BART analysis and provides well-developed presumptive NOx emissions limits. Until recently, Colorado recognized the importance of following Appendix Y when establishing BART. For example, in its April 12, 2006 BART Analysis Guidance, the Division recognized that Appendix Y should guide its BART analysis of power plants, including Hayden. *Id.* ("All affected sources will have to conduct a BART Analysis, following the procedures in Appendix Y"). In fact, Colorado's existing BART determination for Hayden -- which the Division now seeks to change -- is based upon the presumptive limits of Appendix Y for NOx emissions. The Appendix Y presumptive limits, and current BART NOx emissions limits for Hayden, are 0.39lb/MMBtu for dry bottomed wall fired units burning bituminous coal, such as Unit 1 at Hayden, and 0.28lb/MMBtu for tangential fired units burning bituminous coal, such as Unit 2 at Hayden.

Now the Division seeks to abandon its previous, Appendix Y-based BART determinations and make new, unsupported NOx BART determinations for Hayden and Craig. The proposed revised BART determinations for Hayden Station Units 1 and 2 set NOx emissions limits at 0.089 and 0.07 lb/MMBtu, respectively. These proposed limits are **four times** more stringent than the presumptive NOx emissions limits in Appendix Y. The Division has failed to justify why BART NOx emissions limits **four times** more stringent than those found in Appendix Y should be imposed, particularly given the fact that neither federal law, Colorado state law, nor the facts have changed since the Division made its original BART determinations a few years ago in accordance with Appendix Y. Ignoring the Appendix Y presumptive limits, when such limits are appropriate and applicable, is arbitrary and capricious.

2. The Division's imposition of post-combustion NOx control is contrary to federal BART guidance.

EPA's preamble for the federal regional haze rules and the other related guidance are clear that "combustion controls",[2] such as low NOx burners ("LNBs") and over-fire air ("OFA") (in some form), are "BART technology" for the Hayden units (which is consistent with the existing BART determination for these units). In the preamble to Appendix Y and the Regional Haze rules, EPA stated that, except for cyclone boilers, the "types of current combustion control technology options assumed include low NOx burners, over-fire air, and coal reburning." 70 FR

[2] "Combustion controls" refer to those controls and methods used to control NOx emissions during the fuel combustion process. "Post-combustion controls" refer to those controls that are imposed downstream of the combustion process; generally these controls are a type of treatment applied to the exhaust gases.

39134; *see also* 39144 ("For all other coal-fired units, our analysis assumed these units will install current combustion control technology."). In fact, in the Technical Support Document used to develop the presumptive BART NOx emissions limits, EPA explained that the "methodology EPA used in applying current combustion control technology to BART-eligible EGUs" included applying "a complete set of combustion controls. A complete set of combustion controls for most units includes a low NOx burner and over-fire air." "Technical Support Document, Methodology for Developing NOx Presumptive Limits," EPA Clean Air Markets Division, pg. 1 (dated June 15, 2005).

EPA's preamble to the Regional Haze Rule and Appendix Y identify post-combustion controls for NOx, such as selective catalytic reduction ("SCR") and non-selective catalytic reduction ("SNCR"), as "BART technology" for **only** "cyclone" units. Hayden units 1 and 2 are not cyclone units. EPA made it clear that for "other units, we are not establishing presumptive limits based on the installation of SCR." 70 FR 39136. Therefore, EPA's presumptive "BART technology" is LNBs and some type of OFA. EPA further elaborated in the preamble on the SCR costs, stating that although "States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types." *Id.*

Until recently, Colorado properly followed Appendix Y. In the Division's April 12, 2006 BART Analysis Guidance, the Division stated that "Post Combustion Controls, such as Selective Catalytic Reduction and Non-Selective Catalytic Reduction do not have to be considered as part of the BART analysis unless the source is a cyclone furnace." The Division's existing BART determination for Hayden identifies modified LNBs, OFA, or new burners as BART for NOx. Colorado's current BART rules, consistent with Appendix Y, do not allow Colorado to impose post-combustion NOx controls as part of BART. *Id.* at IV.B.

Now, the Division seeks to hastily reverse course, ignore Appendix Y and other federal guidance, delete its own "no post-combustion control" rule that was based upon Appendix Y, and require Hayden to install the most expensive post-combustion controls, SCR. These actions are arbitrary and capricious, and should not be allowed.

3. The Division improperly analyzed the required BART criteria.

According to the federal Clean Air Act, the Division must analyze five different factors when establishing BART: (1) the costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of visibility improvement that may reasonably be anticipated from the use of BART. 42 U.S.C. § 7491(g)(2). While the Division alleges that it analyzed these five criteria, a review of the record demonstrates that the Division improperly analyzed at least two factors (cost-effectiveness and visibility improvement) and gave no weight to at least one other factor (energy and non-air quality environmental impacts).

3.A. The Division improperly analyzed the cost-effectiveness criteria.

The Division improperly analyzed the "cost-effectiveness" criteria in several ways. First, as explained below in section 3.C., the Division placed undue emphasis on this criteria to the exclusion of others. Second, the Division has formulated a new "cost-effectiveness" analysis for the proposed current BART rulemaking that overemphasizes this criteria and strays from the parameters established for this criteria in Appendix Y. In this regard, the Division proposes a cap for NOx removed at $5,000/ton, and states that "[t]he cost criteria presented above is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls." RH-SIP Proposed Revisions at 49 (September 2, 2010).

The $5,000 per ton threshold, however, is contrary to the Appendix Y guidance which implies that costs per ton above $1,500 are not considered to be cost effective. In the preamble to the federal regional haze rules, EPA stated that 75% of the electrical generating units ("EGUs") in the entire country would have BART NOx removal costs between $100 and $1,000 per ton, and almost all of the remaining EGUs could install sufficient BART NOx control technology for less than $1,500 per ton.[3] EPA also recognized in the preamble that SCR was generally not cost effective for EGUs, except for EGUs with cyclone boilers (where the cost per ton was less than $1,500 per ton, with an average of $900 per ton).[4] Based upon EPA's preamble, BART NOx control technology that costs more than $1,500 per ton should not be considered "cost effective." Other states, and Colorado's earlier 2006 BART Analysis Guidance, also do not support the $5,000 per ton cost-effectiveness threshold.[5]

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[3] "The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $ 100 to $ 1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air ("ROFA"), which has already been demonstrated on a variety of coal-fired units. Based on the data before us, the costs of such controls in most cases are less than $ 1500 per ton." 70 FR 39135.

[4] "We also analyzed the installation of SCRs at BART-eligible EGUs, applying SCR to each unit and fuel type. The cost-effectiveness was generally higher than for current combustion control technology except for one unit type, cyclone units. Because of the relatively high NO[X] emission rates of cyclone units, SCR is more cost-effective. Our analysis indicated that the cost-effectiveness of applying SCR on coal-fired cyclone units is typically less than $ 1500 a ton, and that the average cost-effectiveness is $ 900 per ton. As a result, we are establishing a presumptive NO[X] limit for cyclone units based on the use of SCR. For other units, we are not establishing presumptive limits based on the installation of SCR. Although States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types." 70 FR 39135-36.

[5] Many states have determined that BART NOx controls at less than $5,000 are not cost-effective: LNB/OFA at $135 per ton at Nebraska City Station Unit 1 (and not requiring the

Third, the Division should not apply a BACT cost-effectiveness analysis in place of the required BART analysis. EPA statements make clear that a BART and BACT analysis are not the same.[6] *See also* SRP's Pre-Hearing Statement.

Finally, while the Division established a threshold for "average cost effectiveness" in the proposed BART rulemaking, the Division failed to establish such thresholds for "incremental cost effectiveness." Appendix Y explains that in "addition to average cost effectiveness of a control option, you should also calculate incremental cost effectiveness. You should consider the incremental cost effectiveness in combination with the average cost effectiveness when considering whether to eliminate a control option." *Id.* at IV.D.4.e.1. The Division previously recognized this position in its previous BART rulemaking (formally adopted on March 16, 2006). In the Statement of Basis for the 2006 rules, the AQCC stated that "sources must evaluate the costs of compliance including the average cost effectiveness and the **incremental cost effectiveness** of each technology that is feasible at the source." *Id.* at I.JJ.

However, the Division's current NOx control analysis, as reflected in the proposed BART rule revisions, focuses solely on average cost-effectiveness. ("Accordingly, as part of its

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$2,705 per ton SCR option); and LNB/FGR at $716 and $1,070 per ton for units 1 and 2 at Nevada's Fort Churchill plant (and not requiring LNB/SCR at $6,000 per ton). North Dakota found that SCR, coal reburn, and related options were not cost effective (at costs ranging from $4,300 to over $13,000 per ton) for the Leland Olds station, although it did find that SOFA and SNCR at $2,487 per ton were cost effective.

[6] "Although very similar in process, BART reviews differ in several respects from the BACT review described in the NSR Draft Manual. First, because all BART reviews apply to existing sources, the available controls and the impacts of those controls may differ from source to source. Second, the CAA requires you to take slightly different factors into account in determining BART and BACT. In a BACT analysis, the permitting authority must consider the "energy, environmental and economic impacts and other costs" associated with a control technology in making its determination. In a BART analysis, on the other hand, the State must take into account the "cost of compliance, the remaining useful life of the source, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, and the degree of improvement in visibility from the use of such technology" in making its BART determination. Because of the differences in terminology, the BACT review process tends to encompass a broader range of factors. For example, the term "environmental impacts" in the BACT definition is more broad than the term "non-air quality environmental impacts" used in the BART definition. Accordingly, there is no requirement in the BART engineering analysis to evaluate adverse air quality impacts of control alternatives such as the relative impacts on hazardous air pollutants, although you may wish to do so. Finally, for the BART analysis, there is no minimum level of control required, while any BACT emission limitation must be at least as stringent as any NSPS that applies to the source." 69 FR 25184, 25218-9.

five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.") RH SIP at 6.4.3, pg. 48. The Division's RH SIP section on Hayden does not even mention "incremental cost effectiveness," only "average cost-effectiveness." The Division's failure to establish a threshold for "incremental cost effectiveness," or to consider it in any meaningful fashion, has resulted in an incomplete cost effectiveness analysis. In other words, the Division completed just one-half of the job.

3.B. The Division improperly analyzed the visibility improvement criteria.

The proposed BART rulemaking states that $5,000/ton is reasonable for certain control technologies (SCR) if they improve visibility by 0.5dv, but also finds that $5,000/ton is reasonable for other control technologies (SNCR) if they improve visibility by 0.2dv. RH-SIP Proposed Revisions (September 2, 2010). The Division provides no reasonable basis for using the 0.5dv and 0.2dv standards. Of particular note, nothing in Appendix Y supports the Division's use of these thresholds. If one deciview is the smallest perceptible change in visibility, then a 0.2dv improvement is one fifth of what would even be perceptible. The Division's use of these visibility improvement criteria is unsupported.

In addition, the Division bases its conclusions on the results of the CALPUFF modeling which were intended to be used as a screening model to determine which BART units would be required to install BART controls. The Division has made no effort to demonstrate what the actual visibility improvement that will occur in the Class 1 areas or progress will be made towards improving the visibility in the Class 1 areas during the 20% worst visibility days as required by the regional haze rules. Also, the CALPUFF modeling done by the Division overestimates the NOx-related visibility impacts of the Hayden plant. *See* SRP's Preliminary Pre-Hearing Statement, incorporated herein by reference.

3.C. The Division failed to adequately consider energy and non-air quality environmental impact criteria.

The proposed BART rulemaking simply ignores one of the five criteria mandated for BART review: energy and non-air quality environmental impacts. In its 2006 BART Analysis of Controls for Hayden, the Division identified several negative impacts related to the SCR control option. *Id.* at 20. Among these negative impacts, the Division recognized that "SCR systems require additional auxiliary power or power from the existing flue gas fan systems" and that "SCR increases levels of ammonia, and may create a 'blue plume,' if ammonia rates are not adequately controlled." The Division also recognized in the 2006 Hayden BART analysis ammonia storage and transportation are dangerous, and that an "accidental atmospheric release of anhydrous ammonia can be hazardous." *Id.* In the proposed RH SIP, the Division recognized that SCRs would have "increased power needs, potential for ammonia slip, potential for visible emissions, [and] hazardous materials storage and handling." *Id.* at 6.3.4.5., pg. 68.

In the Statement of Basis for the 2006 rules, the AQCC stated that "energy impacts including direct energy consumption for each technology . . . **must be evaluated**." *Id.* at I.JJ. Additionally, the 2006 Statement of Basis for the BART rules also said that "sources **must evaluate** any increases in hazardous waste, wastewater, or other waste products . . . ." *Id.*

However, in the "new" Hayden BART Control Analysis, the Division did not "evaluate" energy and environmental impacts from SCRs. The Division simply listed the impacts, without any analysis or evaluation. In the Hayden BART Control Analysis, the Division admits that the "dollars per ton control costs, coupled with the notable visibility improvements leads the state to this determination." *Id.* at 22. No analysis of energy and non-air quality environmental impacts was performed. These factors were simply ignored, despite the fact the Division already had identified negative impacts related to SCRs. The Division's failure to address this criteria in its new, modified Hayden BART determination is arbitrary and capricious.

4. The Division's complete reversal of its Hayden BART determinations is arbitrary and capricious.

In the Division's April 12, 2006 BART Analysis Guidance, the Division stated that "BART for NOx will be based upon a complete set of current combustion controls. A complete set of current combustion controls is considered to be Low NOx burners and overfire air. If the emission levels achieved by these controls meet the presumptive levels, BART will be determined to have been achieved, unless the BART analysis indicates a lower level is appropriate." In 2006, the Division conducted the BART analysis for the Craig and Hayden plants, determining that then-current combustion controls ("LNBs and OFA) at both plants were BART.

Now, without any basis or justification, the Division has reversed itself. The Division's proposed revisions to the Colorado BART rules remove the language that provided that "coal fired power plants that meet, or will meet with proposed controls, the presumptive limits set forth in IV.A.3 and have submitted an analysis demonstrating the appropriateness of applying these limits shall be presumed to meet the BART analysis requirements, absent a contrary showing." 5 CCR 1001-5(IV.A.2). Also, the proposed revisions to 5 CCR 1001-5 delete language from § IV.B. that provided "[EGU's] and Fossil Fuel Boilers do not need to consider post combustion controls for NOx purposes in the BART analysis and the Division may not require post combustion control for NOx purposes." Instead, the Division is proposing a rulemaking that ignores Appendix Y's presumptive limits and would make post-combustion controls, not current combustion controls, BART for NOx at the Hayden plant. *See* BART Analysis – PSCo Hayden Station at 22.

The Division points to no change to the legal requirements of the BART analysis nor to any new, relevant facts. Indeed, other than the apparent inappropriate influence of EPA Region 8 on Division's BART determinations, nothing seems to have changed since 2006. If the law and facts have not changed since 2006, then how can the Division's BART determination change? How can the AQCC change the BART determinations if no new evidence or legal standards are presented?

Neither federal or state law allows a BART determination to be changed once made. Unlike the PSD or MACT programs, a BART determination is a singular event, and is not intended to be modified or redone once completed. Once a BART determination is made, state air quality agencies can only impose additional "regional haze" requirements through "reasonable progress goals" and "long term strategy." 40 C.F.R. 51.308. The Division's "flip-flopping" of BART determinations is the very essence of arbitrary and capricious conduct and should not be accepted by the AQCC.

5. The Division's Modeling Overestimated NOx Emissions and the Related Visibility Impacts, Materially Affecting the Division's BART Determinations.

The Division overestimated the visibility impacts from post-combustion NOx controls at Hayden and Craig because the Division: 1) relied on the maximum 24 hour NOx emissions, rather than a more representative 30 day average, when conducting its modeling; 2) relied upon the CALPUFF model without modifying certain assumptions, which overestimates NOx emissions for the EGUs; and 3) failed to analyze actual visibility improvements in the Class I areas that would occur on the 20 worst days, as required by the regional haze rules. PacifiCorp adopts and incorporates the arguments and evidence submitted by Tri-State, SRP, and PSCo regarding these issues.

III. ISSUES TO BE RESOLVED

PacifiCorp identifies the factual and legal issues discussed in Section II above as issues for the AQCC to resolve. Additionally, the AQCC should reject the Division's proposed changes to the BART rules and RH SIP, particularly the Division's attempt to change the BART determination for the Hayden plant, as well as the Craig plant.

IV. EXHIBITS

PacifiCorp has not yet identified the exhibits it will use at the hearing. PacifiCorp reserves the right to use as an exhibit any document, or portion thereof, of any document cited herein or by other parties. PacifiCorp also reserves the right to list exhibits, or make additional arguments, as part of its rebuttal.

V. WITNESSES

PacifiCorp anticipates calling as witnesses: William K. Lawson, Director Environmental Services, PacifiCorp Energy; who will testify regarding the Division's improper application of the cost-effectiveness and visibility improvement criteria; and Cathy S. Woollums, Senior Vice President, Environmental, and Chief Environmental Counsel of MidAmerican Holdings Company, who will testify regarding the Division's cost-effectiveness threshold. Legal counsel for PacifiCorp, including Mike Jenkins, Blaine Rawson, or Katheryn Coggon, may present legal arguments and comments at the hearing also. PacifiCorp reserves the right to call additional witnesses necessary for rebuttal or other purposes.

Respectfully submitted this 27th day of October.

By___/s/ Katheryn J. Coggon_____

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ATTORNEYS FOR PACIFICORP ENERGY

CERTIFICATE OF SERVICE

I hereby certify that on October 27, 2010, the undersigned served a copy of the foregoing **PACIFICORP'S PRELIMINARY PRE-HEARING STATEMENT** on the following by email:

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NOTE TO THE PARTIES: Email service between the parties for prehearing statements and any other materials to be filed with the Commission Office is allowed. Please be sure that all parties are copied on the emails.		
Party Status Statements due to the Commission Office, Attorney General's Office, Division Office	September 20, 2010 at 5:00 p.m.	4300 Cherry Creek Drive South EDO-AQCC-A5 Denver, CO 80246
Status Conference	September 27, 2010 at 2:00 p.m.	4300 Cherry Creek Drive South Building C, Conference Room C1E
Final Prehearing Statement due to the Commission Office and everyone listed on the Party Status List	October 27, 2010 at 5:00 p.m.	4300 Cherry Creek Drive South EDO-AQCC-A5 Denver, CO 80246
Pre-Hearing Conference	November 1, 2010 at 1:00 p.m.	4300 Cherry Creek Drive South Building C, Conference Room C1E
Rebuttal Statements due to the Commission Office and everyone listed on the Party Status List	November 8, 2010 at 5:00 p.m.	4300 Cherry Creek Drive South EDO-AQCC-A5 Denver, CO 80246
Rulemaking Hearing Date	November 18, 2010 at 9:00 a.m.	4300 Cherry Creek Drive South Building A, Sabin Conference Room
CERTIFICATE OF SERVICE		
I do certify that a true and exact copy of the Party Status List for the upcoming Rulemaking Hearing regarding proposed revisions to the Regional Haze SIP and Regulation Number 3, Part F was emailed to the following on September 21, 2010		
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/s/ Karen D. Olsten

OPUC Data Request 756

Hayden SCRs - Please refer to PAC/2600, Ralston/37 at lines 15 through 19. Please explain why the Company would have performed an analysis of the early retirement at Hayden 1 where no coal contract termination costs applied if this was not a possible outcome.

Response to OPUC Data Request 756

The Hayden Unit 1 early retirement results were dependent upon coal contract termination provisions. If applicable, change-in-law termination provision eliminates take-or-pay coal contract costs, and present value of revenue requirements differential (PVRR(d)) results favor early retirement. Absent applicability, change-in-law termination provision of coal contract does not eliminate take-or-pay costs, and PVRR(d) results favor selective catalytic reduction except when high carbon dioxide prices are assumed.

In the reply testimony of Dana M. Ralston, page 37, lines 22, and page 38, lines 1-2 states "Yes. Coal contract termination costs would have applied because PacifiCorp did not have legal grounds to trigger the change-in-law provision or the CPCN termination provision in the Hayden coal supply agreement (CSA)."

OPUC Data Request 757

Hayden SCRs - Please refer to PAC/2600, Ralston/41. Please provide evidence to support the statement that "in March of 2014, the Company initiated an open-ended Request for Expressions of Interest in Hayden Units 1 and 2, with a requested response date of April 18, 2014. No expressions of interest were ever received."

Response to OPUC Data Request 757

Please refer to Attachment OPUC 757, which provides a copy of the request for expressions of interest issued by the Company on March 14, 2014.

From: Johnson, Paul J {Mkt Function}
To: Johnson, Paul J {Mkt Function}
Cc: Griswold, Bruce; Teply, Chad
Subject: PacifiCorp Request for Expression of Interest to Acquire Generating Assets
Date: Friday, March 14, 2014 10:19:57 AM
Attachments: Craig and Hayden REI_Cover Letter.pdf
Exhibit_Craig_REI.pdf
Exhibit_Hayden_REI.pdf

PacifiCorp Request for Expression of Interest (REI)

PacifiCorp has an interest in identifying qualified third parties ("Bidders") to acquire PacifiCorp's undivided ownership interests in:

(a) the Craig generating facilities Units 1 and 2, together with its ownership interest in any common facilities or other related assets with respect to such facilities, including PacifiCorp's ownership interest in the adjacent Trapper coal mine (collectively, the "Craig Assets"),
(b) the Hayden generating facilities Units 1 and 2, together with its ownership interest in any common facilities or other related assets with respect to such facilities (collectively, the "Hayden Assets"), or
(c) both the Craig Assets and the Hayden Assets.

Please see attached three documents – Cover Letter, Craig REI and Hayden REI.

To be eligible to be selected as a Bidder, a complete response to this REI (a "Response") (including the documents and information described in the attached exhibits) must be received by PacifiCorp no later than **5:00 p.m., Pacific Time, on April 18, 2014**.

All communication or inquiries related to the process and Craig and Hayden should be directed to PacifiCorp. Please direct all inquiries to the following individuals.

Bruce Griswold
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Director, Short-Term Origination
503-813-5218
PacifiCorp, Commercial & Trading
825 NE Multnomah Street, Suite 600
Portland, OR 97232

Chad Teply
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Vice President, Resource Development & Construction
801-220-4715

CASE: UE 374
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2302

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Sierra Club Data Request 1.4

Refer to the Direct Testimony of Mr. Rick Link, page 107 at 9-14. "Based upon the breakeven relationship described above, PacifiCorp determined that the SCR emission control systems remained the most economical environmental compliance option for Jim Bridger Units 3 and 4, benefiting customers by approximately $130 million more than the gas-conversion alternative… When evaluating natural-gas prices before issuing the FNTP…"

(a) Provide the work papers demonstrating the $130 million benefit described above.

(b) Provide contemporaneous documentation, including correspondence, emails, memoranda, presentations, and the like demonstrating that the Company had assessed, and affirmed a ratepayer benefit of $130 million prior to signing the FNTP. If an electronic document is produced, provide evidence of the time- and date-stamp for that document.

(c) Identify the individual or individuals who produced that documentation, and identify the recipients of that documentation.

(d) Confirm or deny: the Company did not re-run System Optimizer to assess the Jim Bridger SCR installation decision after the determination of the $183 million benefit.

Response to Sierra Club Data Request 1.4

(a) Please refer to Confidential Attachment Sierra Club 1.4-1. Tab "Trend Data CONF," cell E37 reports the $130 million selective catalytic reduction (SCR) benefit. Please also refer to the direct testimony of company witness, Rick T. Link, specifically Confidential Exhibit PAC/710, Link/1 (PacifiCorp's regression analysis for changes in natural gas prices reflected in the official forward price curve (OFPC)).

(b) PacifiCorp objects to this data request to the extent it implies that contemporaneous documentation is a pre-requisite to establishing the prudence of a utility's actions. Prudence determinations are based on an objective standard of reasonableness. If the record demonstrates that a challenged business decision was objectively reasonable considering established historical facts and circumstances, the utility's decision will be upheld as prudent without contemporaneous documentation of the utility's actual subjective decision making process. *In the Matter of the Application of PacifiCorp for an Accounting Order Regarding Excess Net Power Costs*, Docket UM 995, Order 02-469 (July 11, 2002).

Notwithstanding this objection, PacifiCorp responds as follows:

PacifiCorp made its decision to proceed with the Jim Bridger SCR investment in late May 2013. This decision was supported by voluminous evidence, including PacifiCorp's economic analysis included in Confidential Volume III of PacifiCorp's 2013 Integrated Resource Plan (IRP) filed in April 2013, detailed cost estimates, fully litigated state regulatory approvals received in May 2013, and environmental permitting and reviews. This evidence is summarized in PacifiCorp's appropriation approval request (APR), dated April 2013, and APR update, dated May 22, 2013. Please refer to Confidential Attachment Sierra Club 1.4-2 and Confidential Attachment Sierra Club 1.1-1 (file "LNTP Jim Bridger Units 3 and 4 SCR Systems Approval Request Memo_20130522 CONF"), respectively for these documents.

To minimize the risks of the Jim Bridger SCRs for customers, PacifiCorp negotiated an innovative engineer, procure, construct (EPC) contract that allowed the company to delay significant investment in the Jim Bridger SCRs to the last possible date, December 1, 2013, while still ensuring that the company could cost-effectively meet its compliance deadlines. The EPC contract allowed the company to withdraw if material changes before December 1, 2013 impacted the economics or the company's ability to implement the SCR projects.

Before issuing the final notice to proceed (FNTP) under the EPC contract, PacifiCorp reviewed key decision factors for material, adverse changes, including the natural gas prices reflected in the then most recent OFPC dated September 2013. PacifiCorp's regression analysis included in Mr. Link's direct testimony, specifically Exhibit PAC/710, Link/1 showed an updated present value of revenue requirements differential (PVRR(d)) of $130 million supporting the SCR decision based on that OFPC. Additionally, PacifiCorp reviewed 10-year budget projections based on the October 2013 mine plan showing that Jim Bridger coal costs were not expected to increase significantly, and a significant cost reduction the company negotiated in the EPC contract. The company also verified that none of its third-party forecast providers had projected increases in carbon costs in response to President Obama's 2013 Presidential Memorandum on carbon emissions.

Company witness, Chad A. Teply personally performed the review of these factors, in regular consultation with Mr. Link and members of PacifiCorp's fuels group, and has testified to this review in other state proceedings, including most recently in PacifiCorp's California general rate case, Application 18-04-002. In that proceeding, the California Public Utilities

Commission concluded that the Jim Bridger SCR investment was prudent. Please refer to Decision 20-02-025.

On December 5, 2013, PacifiCorp summarized various considerations supporting the FNTP in a memorandum, also provided in Confidential Attachment Sierra Club 1.4-3.

(c) The documentation was produced at the direction of company witness Rick T. Link. The recipients were two regulatory filings: (1) Application for a Certificate of Public Convenience and Necessity filed with the Wyoming Public Service Commission on August 7, 2012 (Docket 20000-418-EA-12), and (2) Voluntary Request for Approval of Resource Decision filed with the Public Service Commission of Utah on August 24, 2012 (Docket 12-035-92). Please also refer to the company's response to subpart (b) above.

(d) The company confirms that it relied upon the System Optimizer model (SO model) results from February 2013, which were updated for the 2013 IRP, to develop its regression analyses set forth in Mr. Link's direct testimony, specifically Confidential Exhibit PAC/710, Link/1, and Confidential Exhibit PAC/711, Link/1. The modeling results from February 2013 included a range of different natural gas and carbon price scenarios which allowed the results to remain current as these inputs fluctuated in 2013 and demonstrated that it would take a significant change of circumstances for the SCR benefits to dissipate. In addition, the regression graphs for natural gas and carbon prices are a close representation of what the SO model would produce. These graphs allowed the company to rapidly re-assesses how a significant assumption like natural gas prices affected the relative economics of SCRs versus natural gas conversion. In advance of issuing the FNTP, the company relied upon these graphs in confirming that the company's May 2013 decision to proceed with the SCR investment remained the most beneficial option for customers.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Sierra Club Data Request 8.2

Refer to PAC/2300 Link/16:7-18 with respect to the scenarios examining avoided transmission in Energy Gateway.

(a) Mr. Link states that, with respect to the "Utah and Wyoming pre-approval cases," and "…in response to Sierra Club's concern…" Refer to the rebuttal testimony of Mr. Link before the Wyoming Public Service Commission in Docket 20000-418-EA-12, filed March 4, 2013, page 40:4-9, stating "Sierra Club has taken the position that if Jim Bridger 3 and 4 were retired and replaced with a resource located closer to load centers that the need for Energy Gateway transmission investments would be alleviated. Consequently, Sierra Club testifies that deferral of Energy Gateway costs should be considered as a benefit to an early retirement outcome and that this benefit was not captured in the Company's analysis. Explain how the analytical result, shown at PAC/2300 Link/16:12-17 addresses this specific concern.

(b) Confirm or deny: The Company did not present this specific analysis in the 2013 IRP or 2013 IRP Update. If denied, provide a citation to where the analysis was discussed or results indicated.

(c) Confirm or deny: The avoided Energy Gateway scenario was applied to the base case, which included the Jim Bridger SCR retrofits.

(d) Confirm or deny: The avoided Energy Gateway scenario excluded more Energy Gateway segments than just Anticline to Populus.

(e) Confirm or deny: PacifiCorp did not assess a scenario in which Jim Bridger 3 & 4 units were retired in 2015/2016 and the Energy Gateway segment from Anticline to Populus (only) was also avoided. If denied, explain.

(f) Confirm or deny: PacifiCorp did not assess a scenario in which Jim Bridger 3 & 4 units were retired in 2015/2016 and the Energy Gateway project was resized relative to the base case to carry the same amount of Wyoming wind as the base case. If denied, explain.

(g) Confirm or deny: PacifiCorp did not assess a scenario in which Jim Bridger 3 & 4 units were repowered to gas in 2015/2016 and the Energy Gateway segment from Anticline to Populus (only) was also avoided. If denied, explain.

(h) Confirm or deny: PacifiCorp did not assess a scenario in which Jim Bridger 3 & 4 units were repowered to gas in 2015/2016 and the Energy Gateway project was resized relative to the base case to carry the same amount of

Wyoming wind as the base case. If denied, explain.

(i) Confirm or deny: PacifiCorp did not asses a scenario in which Jim Bridger 3 & 4 units were retired in 2020/2021 and the Energy Gateway segment from Anticline to Populus (only) was also avoided. If denied, explain.

(j) Confirm or deny: PacifiCorp did not asses a scenario in which Jim Bridger 3 & 4 units were retired in 2020/2021 2016 and the Energy Gateway project was resized relative to the base case to carry the same amount of Wyoming wind as the base case. If denied, explain.

(k) Confirm or deny: PacifiCorp did not asses a scenario in which Jim Bridger 3 & 4 units were repowered to gas in 2020/2021 and the Energy Gateway segment from Anticline to Populus (only) was also avoided. If denied, explain.

(l) Confirm or deny: PacifiCorp did not asses a scenario in which Jim Bridger 3 & 4 units were repowered to gas in 2020/2021 and the Energy Gateway project was resized relative to the base case to carry the same amount of Wyoming wind as the base case. If denied, explain.

(m) Provide the work papers underlying the valuation in PAC/2300 Link/16:12-17 including both scenarios examined to arrive at the difference. Include input and output files from System Optimizer, and any spreadsheets or worksheets used by the Company to process or assess the model outputs from System Optimizer.

Response to Sierra Club Data Request 8.2

(a) Please refer to the rebuttal testimony of Rick T. Link before the Wyoming Public Service Commission in Docket 20000-418-EA-12, filed March 4, 2013, page 40:3-23, pages 41-43, and page 44:1-12.

(b) Confirmed.

(c) Confirmed.

(d) Denied.

(e) Confirmed. Please refer to the Company's response to subpart (a) above.

(f) Confirmed. Please refer to the Company's response to subpart (a) above.

(g) Confirmed. Please refer to the Company's response to subpart (a) above.

(h) Confirmed. Please refer to the Company's response to subpart (a) above.

(i) Confirmed. Please refer to the Company's response to subpart (a) above.

(j) Confirmed. Please refer to the Company's response to subpart (a) above.

(k) Confirmed. Please refer to the Company's response to subpart (a) above.

(l) Confirmed. Please refer to the Company's response to subpart (a) above.

(m) Please refer to the Confidential Attachment Sierra Club 8.2.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Sierra Club Data Request 8.3

Refer to PAC/2500, Owen/16:8-19, with respect to gas conversion costs.

(a) Provide the Company's estimate of the costs of gas conversion at Naughton 3 as projected in September 2013.

(b) Provide a table of results of EPC contract bids for the gas conversion at Naughton 3 as known in January 2014.

(c) Provide Mr. Owen's work papers estimating the specific change on line 14, from costs "originally anticipated" to "significantly higher."

(d) Provide a definition and citation for the common use of the term "order of magnitude."

(e) Provide Mr. Owens' estimate of the present value of revenue requirements that would have "negatively impacted the competitiveness of the natural gas conversion."

Response to Sierra Club Data Request 8.3

(a) In 2013, PacifiCorp estimated that a natural gas conversion at Naughton Unit 3 would cost between $29 million and $30.4 million.

(b) The requested information is commercially sensitive and highly confidential. The Company requests special handling. Please contact Matt McVee at (503) 813-5585 to make arrangements for review.

(c) Mr. Owen's statement relates to his review of the evaluations conducted at the time of PacifiCorp decision making, and are not workpapers produced by Mr. Owen or at his direction. Some of the information on which Mr. Owen based this statement is commercially sensitive third-party information and highly confidential. The Company requests special handling. Please contact Matt McVee at (503) 813-5585 to make arrangements for review. Confidential information is provided as Confidential Attachment Sierra Club 8.3.

(d) "Order of magnitude" is commonly used in two ways: (1) to describe a size of value by approximate factors of 10; and / or (2) to mean much bigger or smaller. As used in Exhibit PAC/2500, Owen/14, the term is preceded by the phrase 'were significantly higher' when describing costs, thus, Mr. Owen used the term according to its second common usage.

Citation: https://www.mathsisfun.com/definitions/order-of-magnitude.html

(e) Mr. Owen's testimony does not state that he calculated an estimate of the present value of revenue requirements. The quoted statement in Mr. Owen's testimony reasonably deduces that the competitiveness of natural gas conversion would be negatively impacted if the estimated cost to implement a natural gas conversion were higher than originally assumed.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

CUB Data Request 5

Please provide the total rate base associated with the Jim Bridger Unit 4 SCR when it became used and useful.

1st Revised Confidential Response to CUB Data Request 5

This response replaces, in its entirety, the Company's original response dated July 8, 2020, which was inadvertently provided on a non-confidential basis. No other changes have been made to this revised response other than the confidential designation of the information identified below.

The Company interprets this request to be asking for the gross plant value of the Jim Bridger Unit 4 selective catalytic reduction (SCR) system at its in-service date.

The gross plant value of the Jim Bridger Unit 4 SCR at its November 2016 in-service date was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. After completion of close-out activity of the project, the final cost was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

CUB Data Request 4

Please provide the total rate base associated with the Jim Bridger Unit 3 SCR when it became used and useful.

1st Revised Confidential Response to CUB Data Request 4

This response replaces, in its entirety, the Company's original response dated July 8, 2020, which was inadvertently provided on a non-confidential basis. No other changes have been made to this revised response other than the confidential designation of the information identified below.

The Company interprets this request to be asking for the gross plant value of the Jim Bridger Unit 3 selective catalytic reduction (SCR) system at its in-service date.

The gross plant value of the Jim Bridger Unit 3 SCR at its November 2015 in-service date was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. After completion of close-out activity of the project, the final cost was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

CASE: UE 374
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2303

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Staff Exhibit 2303 is Confidential Subject to Protective Order No. 20-040

CASE: UG 374
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2400

Rebuttal Testimony

Redacted
July 24, 2020

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC).My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1301.

Q. What is the purpose of your testimony?

A. I present Staff's response to intervenor opening testimony and Company reply testimony regarding the Company's proposed Annual Power Cost Adjustment (APCA). This includes the Company's proposal to remove deadbands, sharing, and earnings test from the PCAM, combine the TAM and PCAM into a single filing, and update certain TAM guidelines.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Intervenor Response..... 2
Company Response 5

INTERVENOR RESPONSE

Q. Please summarize parties' positions regarding the Company's proposed APCA.

A. No party supported the Company's proposal. Many of the parties' arguments mirrored those raised by Staff in its opening testimony. Staff will provide a brief synopsis of each parties' opening testimony positions.

Alliance of Western Energy Consumers (AWEC)

AWEC notes that PacifiCorp's opening testimony did not adequately demonstrate a need for elimination and replacement of the current power cost recovery process.[1] Like Staff, AWEC notes that the PCAM has functioned in line with the Commission's stated goals.[2] AWEC further states that the Company has not established that the shifts in the energy landscape since 2012 exceed normal business risk for an electric utility.[3] AWEC goes on to note that PacifiCorp has asked for a similar mechanism twice before and has addressed the main issue with the DA/RT adjustment. Furthermore, AWEC notes that PGE and Avista have not had similar under-recovery issues of power costs. Lastly, AWEC recommends the Commission come to the following determinations:

- Deny PacifiCorp's request to allow modeling changes in a stand-alone TAM/APCA.

[1] AWEC/100, Mullins/30, lines 10 and 11.
[2] *Ibid.*
[3] *Ibid.* At 31, lines 4 – 8.

- Deny PacifiCorp's request to update coal costs of mines owned by PacifiCorp in reply testimony.
- Include the impact of the DA/RT adjustment in the transition adjustment calculation.
- Deny the Company's Schedule 200 rate design proposal.
- Deny the Company's proposal for delayed filing of TAM/APCA when concurrent with a GRC.
- Require all workpapers be provided upon initial filing.
- Provide workpapers electronically.

Calpine Energy Solutions (Calpine)

Calpine has a single proposal regarding the APCA/TAM to change the guidelines so that a sample calculation of Schedule 296 is included in the Company's filing.[4]

Oregon Citizens' Utility Board (CUB)

CUB's opening testimony largely mirrors the issues and concerns raised in Staff's opening testimony. CUB summarily states that the Company's proposal represents a shift of risk to COS customers,[5] and that it is not in line with the Commission's previous ratemaking process.[6] CUB goes on to note that the Company's earnings have been largely reasonable overall[7], and that the current mechanism is functioning as intended by the Commission.[8]

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[4] Calpine Solutions/100, Higgins/6, lines 7-11.
[5] CUB/100, Jenks/30, lines 11-13.
[6] *Ibid. Lines 7-8*
[7] *Ibid. At 33, lines 1-13.*
[8] *Ibid. At 44, line 1.*

1 Klamath Water Users Association (KWUA)

2 KWUA does not support PacifiCorp's proposal. It notes that the current
3 structure of the PCAM serves to limit regulatory burden, share forecast risk
4 between shareholder and customer, and incentivize the Company to minimize
5 costs.[9] KWUA argues that PacifiCorp should utilize alternative approaches to
6 fixing the purported issue, which would more directly address the stated
7 problem.[10] Lastly, KWUA notes that if the Commission were to adopts the
8 Company's proposal, the reasonable ROE may need to be changed.[11]

9 **Q. What is Staff's response to party testimony?**

10 A. Staff agrees with the majority of the arguments raised by intervenors.
11 Generally, Staff agrees that the Commission should consider the shifting of
12 risk, Company incentives, the Company's ability to earn a reasonable rate of
13 return, Oregon's ratemaking process, and the goal of the PCAM. Staff also
14 supports Calpine's and AWEC's proposed amendments to the TAM/APCA
15 guidelines.

[9] KWUA/100, Reed/29, lines 1-10.
[10] *Ibid.* At 30, lines 1-17.
[11] *Ibid.* At 31, lines 15-19.

1 **COMPANY RESPONSE**

2 **Q. Please summarize the Company's concerns raised in its Reply**
3 **Testimony?**

4 A. The Company continues to believe that the current PCAM structure is not
5 allowing it to earn its prudently incurred costs. PacifiCorp states that no power
6 cost forecasting software is able to accurately forecast the complexities of
7 operating a modern electric utility.

8 Commission Policy

9 **Q. Does PacifiCorp agree with Staff, CUB, AWEC and KWUA that the PCAM**
10 **is achieving its intended goals?**

11 A. No. PacifiCorp argues that the PCAM "was designed based on the express
12 assumption that under- and over- collections will negate each other over the
13 long term."[12] The Company argues that if the power cost recovery system was
14 operating as intended "there would be a possibility of under-recovery and over-
15 recovery of NPC."[13] The Company notes the Commission's stated response to
16 remedy a persistent forecast error by refining models and improving
17 forecasting of model inputs, and argues that the Company's analysis has
18 shown that GRID cannot be further optimized to fix the problem.[14] The
19 Company also argues that its system is complex, the energy landscape is
20 changing, and the PCAM principles are antiquated and should be

[12] PAC/2000, Wilding/53, lines 19-20.
[13] *Ibid.* At 54, lines 11-12.
[14] *Ibid. At 55 and 56.*

1 reexamined.[15] PacifiCorp also argues that the term "unusual" is not sufficient
2 and would favor the terms unpredictable or prudently incurred.[16] Finally,
3 PacifiCorp argues that revenue neutrality should not be applied to the PCAM
4 design.[17]

5 **Q. How does Staff respond to PacifiCorp's argument regarding power cost**
6 **policy?**

7 A. PacifiCorp argues both that the PCAM is not working as intended and that the
8 design of the PCAM was flawed from the beginning. PacifiCorp's initial claim
9 that the PCAM is not working as intended seems to be based on a conflation
10 between under/over recovery and under/over adjustment. The PCAM is
11 designed to be revenue neutral, which as Staff pointed out in its opening
12 testimony, means that charges and refunds of the PCAM will generally equal
13 out over time depending on the integrity of the power cost forecast. PacifiCorp
14 seems to believe that this implies that the design of the PCAM was meant to
15 result in under/over recovery of power costs, leveling out over time, and not
16 just the adjustments of the PCAM itself. Staff finds no evidence based on the
17 cited Commission order that the intended goal of the PCAM was to balance
18 over and under-recovery over time. The mere fact that the Commission
19 required the PCAM to be revenue neutral implies that the true-up mechanism
20 was not meant to solve the issues raised by the Company. In fact, the same
21 quote noted by the Company from UM 1662, states that the appropriate

[15] *Ibid.*At *57 – 62.*
[16] PAC/3000, Graves/6, lines 1-8.
[17] PAC/3000, Graves/7.

solution for chronic under-recovery should be based in improving the forecast, not in changing the true-up.

PacifiCorp also argues that the current PCAM structure is punitive and the incentives have not worked because PacifiCorp is not realizing an over-recovery of power costs.[18] It also states that no party has identified any kind of operational performance that is believed to have been enhanced or motivated by the existing sharing rules.[19] First, Staff's Opening Testimony, Staff/1300, Gibbens/19-20, lines 19 to 8, includes a list of the decisions made by the Company in the short- and long-term which ultimately influence power costs. Second Staff would note that the Company is moving the goalposts to some degree. The Commission designed the PCAM to incent the Company to minimize power costs, which the current structure clearly does. It is nearly impossible to prove what the Company may or may not have done under a different PCAM structure. It is the same as arguing that the Company's APCA lacks incentives because PacifiCorp has not identified a single thing it would have done to lower power costs if properly incented by the removal of PCAM sharing. The simple fact is that the Company is asking the Commission to change the PCAM from a carrot and stick based incentive to only a stick-based incentive. The APCA is based on retrospective review, while the TAM/PCAM is based on prospective goal setting with a backstop if costs vary significantly from the forecast. The adage, it's easier to ask forgiveness than it is to get

[18] PAC/3000, Graves/12.
[19] PAC/3000, Graves/13, lines 1 and 2.

permission, would indicate that the Company's incentives to minimize costs are reduced under the APCA.

Staff believes that it provided a balanced and fair analysis of the PCAM's compliance with stated goals and design criteria in opening testimony and continues to find the current PCAM structure is achieving those goals.

In the following testimony, Staff will show that it is not clear and apparent that the under-recovery the Company has experienced is the result of uncontrollable system balancing costs. It is more likely the result of either over-optimized GRID sales or inefficient operation by the Company. In either case, the Company has control of the model it implements—in fact, it is changing power cost models on all power cost forecasts moving forward—as well as the ability to become more efficient.

Q. The Company argues that it is not feasible to improve the forecasting model, how does Staff respond?

A. PacifiCorp references the "backcast analysis" performed by the Company in two recent TAM filings as evidence that GRID cannot be further optimized. Staff has two responses: the first is that the Company analyzed two years—2016 and 2017. These years represent the two smallest power cost variance years since the implementation of the PCAM. They are roughly 80% and 90% smaller than the average annual deviation, respectively. The fact that GRID was able to accurately forecast power costs using actuals during years it was already able to reasonably forecast power costs using forecasted data is not all that surprising. The second, is that GRID will no longer be used to forecast

power costs in the future. The Company claims that all power cost forecasting models suffer from the exact same fatal flaw that makes them unable to produce reasonable results, but they have no empirical evidence that AURORA cannot accurately forecast their system.

Q. Will AURORA improve the forecast accuracy?

A. Staff cannot come to a conclusion at this time. PacifiCorp claims that the model has the same perfect foresight as GRID, however the Company has admitted through discovery that options to mitigate over optimization from perfect foresight. In response to Staff DR No. 667, the Company quoted information from Energy Exemplar, the creators of AURORA:

> The optimization solves the commitment patterns one day at a time with a mathematical program. Each day that is solved will include data from a **user specified** number of additional days to ensure that the commitment decisions adequately take into account the system constraints for upcoming hours."[20] They additionally note that there are options to not allow the model to have perfect foresight, "[t]here are options for introducing forecast error into an Aurora simulation. The Dispatch Uncertainty Table and Forecast Error columns in the Zone Definition table allow you to model uncertainty between commitment and dispatch.[21]

Thus, the model may potentially address some of the concerns regarding GRID's dispatch logic. Additionally, Staff understands that Idaho Power, which also utilizes AURORA for power cost forecasting uses a version of AURORA which does not have perfect foresight. It is premature to assert that PacifiCorp is unable to rectify the concern through the Commission recommended approach of fixing the forecast. The Company has already seen a substantial

[20] Staff/2401, PacifiCorp's response to Staff DR No. 667. Emphasis added.
[21] *Ibid.* (emphasis added).

reduction in the average deviation of NPC recovery once the DA/RT mechanism was implemented.

Q. Given the Company's claims that NPC under-recovery is increasing, how can Staff claim that the DA/RT mechanism is resulting in a reduction of NPC recovery?

A. First, the Company utilizes preliminary, unverified 2019 power cost data in much of its reply testimony. Staff does not believe it is proper to draw conclusions, particularly ones that may result in substantial changes to the way in which power costs are recovered from data that has not been properly reviewed and analyzed by Staff and other parties, much less determined as valid by the Commission. Staff does note that adjustments to PCAM data are rare, but that may be a function of the fact that adjustments to the PCAM have not resulted in a rate impact, resulting in, as previously noted, less contested filings. Second, the "trend" which PacifiCorp claims exists is based on 3 years of Commission reviewed data. This is a limited number of data points with which to extrapolate into the future, particularly when the underlying model will be changing. In looking at the average deviation based on the numbers in PAC/2000, Wilding/55, Table 6, the post-DA/RT deviation is roughly 1/3 the size as the pre-DA/RT deviation. If a single out-of-model mechanism was able to reduce the average size of the deviation by two-thirds, an entire new model may be able to provide further benefits.

In looking at the Company's power cost recovery results, Staff notes that in one of three years since the implementation of DA/RT, PacifiCorp has over-

recovered power costs. If over/under recovery were a fifty/fifty proposition, this would occur 38 percent of the time. Even if we consider the 2019 preliminary data, one in four years is still a 25 percent probability. It is impossible to say that GRID with DA/RT is fundamentally flawed based on actual results. Staff also performed some regression analysis on the Company's power cost recovery discussed more in depth later in testimony, one takeway from that analysis was that no trend was apparent when controlling for load variances between actual and forecasted amounts.[22]

Staff also notes that the Company claims in testimony that it only over-recovered in 2016 due to a one-time adjustment related to the abandonment of the Joy longwall miner.[23] This is somewhat misleading, because in the Company's initial filing in UE 327, the 2016 PCAM, noted an over-recovery, even without any adjustment for the longwall miner. The only way the Company can claim that it under-collected without the longwall adjustment is if situs resource accounting is not taken into account.[24]

Q. Does Staff believe that the Commission should not consider whether the PCAM structure is sound in light of evidence of a utility's under-recovery?

[22] Staff/2403, Gibbens/2.
[23] PAC/2000, Wilding/55, footnote 99.
[24] Situs resource accounting is necessary when a particular resource or other NPC item is procured specifically for or otherwise assigned to a state. In this case it is from solar facilities procured to satisfy the solar capacity standard in ORS 757.370. The Company notes in the UE 327 initial filing, "This treatment is necessary to ensure 100 percent of the energy benefits are assigned to Oregon customers, rather than allocated system-wide."

1 A. No. Setting the policy reasons for the PCAM aside for a moment, Staff does
2 not mean to imply that the Commission should never consider whether the
3 PCAM should be adjusted in light of its actual performance. But the fact
4 remains that the current PCAM structure has resulted in PacifiCorp's earnings
5 being closer to its Commission approved return on equity than the Company's
6 proposal would have.[25] . The reason earnings tests are generally included in
7 deferrals is because deferrals are single-issue ratemaking, which allows for the
8 recovery of a discrete set of costs regardless of changes in other costs . For
9 power costs, a true-up of forecasted costs to actual costs is single-issue
10 ratemaking, which long-standing policy supports should consider the utility's
11 earnings prior to a surcharge for customers. If the Company's earnings are
12 such that it is within a reasonable zone of its authorized return, it would be an
13 unfair outcome for customers to further compensate the Company. In this
14 circumstance, the Company is said to be made whole from a ratemaking
15 perspective.

16 **Q. Does Staff believe it is relevant whether Oregon's PCAM structure is an**
17 **outlier in response to the Company's reply testimony?**

18 A. No. Staff continues to believe that the reasonableness of the power cost
19 recovery in each state cannot be simply boiled down to whether each state has
20 deadbands, sharing, earnings test, etc. Staff sees power cost recovery as part
21 of a larger structure that may vary from state to state based on any number of
22 different factors including: the markets the utility operates in, the frequency of

[25] Staff/1300, Gibbens/16.

rate cases, the prospective vs retrospective nature of rate setting, cost based versus performance based rate setting, regulatory review timelines, Commission size, utility size, etc. Staff has not performed an exhaustive review of every state's power cost recovery process, but did generally review the analysis of other states provided by the Company in support of changes to the PCAM. Staff found that Montana, Nevada, North Carolina, Oklahoma, South Dakota, and Washington set power cost rates based on historical power costs and current period costs are only recovered incrementally to the recovery of prior period rates on a periodic basis. This is in contrast to Oregon whose power cost rates are set on a prospective basis, allowing the Company to recover any new reasonable costs as they are incurred. As Staff noted, whether or not power cost recovery includes a deadband or sharing is insufficient to determine whether the recovery process as a whole is reasonable.

Changes since PCAM Implementation

Q. What changes to the energy landscape does the Company cite as reasons to warrant reconsideration of PCAM design?

A. The Company notes the increase in renewable generation on its system, the development of the EIM, resource adequacy (RA) concerns, the potential day-ahead energy market (EDAM), and policy through legislation and executive orders.

Q. Does Staff believe that these changes warrant a shift in power cost recovery?

A. No. PacifiCorp only provides any substantive arguments that renewable generation through RPS compliance, least cost/risk planning, and legislative direction will adversely affect its ability to accurately forecast power costs. The Company has no basis to claim that the EIM, EDAM, or RA concerns will alter the Company's ability to accurately forecast power costs. It is generally believed that the energy landscape is always evolving; any eight-year span of time sees many changes in the energy world.

Q. Does Staff believe that the increase in renewables warrants changes to the PCAM?

A. No, Staff finds the evidence underlying the Company's argument questionable. Staff will be begin by discussing the direct impacts that renewables have on power costs.

The Company's renewable resource portfolio can be broken down into three categories: PacifiCorp owned resources, PURPA resources (QFs), and non-PURPA resources (non-QFs). The Company notes that since 2008, it has added 4,789 MW of new renewable resources.[26] The Company owns 43 percent of this, QFs account for 36 percent, and the remaining 21 percent are non-QFs. Staff believes that in looking at each category closely, the direct impact on power costs shows no indication that they would be better served under the Company's proposal.

Q. Why does Staff believe that the Company-owned resources do not warrant a change in PCAM consideration?

[26] PAC/2000, Wilding/59, line 15.

A. The Company has added a total of 2,055.69 MW of renewable resources. The vast majority of this, 2,055.04 MW is wind. As Staff mentioned in the opening round of testimony, parties to the 2019 TAM agreed to use the P50 capacity factors used to justify PacifiCorp's new and repowered wind fleet. This was in part due to Commission direction in the 2017 IRP order, and subsequently in the Company's RFP for EV 2020 run concurrent to the IRP. In Order No. 18-178, the Commission stated:

> Our conditioned acknowledgement was intended to protect customers by holding PacifiCorp to the benefits forecast in its IRP projections. We stated that PacifiCorp's recovery may be conditioned or limited to ensure project benefits are no less than the assumptions presented in the IRP, listing pre-commercial operational date (COD) risks such as construction cost overruns, delays that impact PTC value, and project costs, and **post-COD risks such as project performance**, tax changes, and resource value relative to market.[27]

In Staff's opening testimony of UE 356, Staff stated:

> Maintaining the use of the P50 forecasts holds PacifiCorp to the NPC benefits forecast in the IRP. Because Staff, parties, and the Commission all have concerns over the prudence of the investment decision, it is not fair, just or reasonable to make customers bear performance risk associated with the EV 2020 plants. Staff notes that should the capacity factors exceed the P50 forecasts, which by definition should occur 50% of the time,[28] Staff's proposal will result in a higher power cost forecast than otherwise would have occurred. This means that barring a PCAM adjustment, the Company has the opportunity to financially benefit from Staff's proposal.[29]

Staff also states:

> Any forecasted wind capacity factor that is below that provided in the cost/benefit analysis in the 2017 IRP will reduce the amount of wind generated in the TAM. Any reduction in wind generation must be made

[27] Order No. 18-178 at 2 (emphasis added).
[28] P50 signifies the statistical confidence level for an estimate in probabilistic Monte Carlo simulations. i.e. 50% of simulated results exceed the P50 estimate.
[29] UE 356, Staff/100, Gibbens/21-22.

> up for by running other generators or making market purchases, which will ultimately result in higher power costs.[30]

If the Company's APCA proposal is adopted, this would result in undoing some of the protections Staff, parties, and the Commission implemented via the 2019 TAM Stipulation. Specifically, the Company would maintain the PTC forecast, but would not hold itself to the P50 forecast for the actual power generated. Staff believes that in order to comply with the Stipulation, the Company would need to remove the PTC and energy generation of the EV 2020 wind projects (both repowered and new wind) from the true-up of power costs. This would require a "with and without" GRID/AURORA run, to value the energy above or below forecast, but as Staff mentioned in UE 356, the Company would be able to realize the benefit of excess energy roughly fifty percent of the time. This is the only way to ensure that customers remain protected and are ensured the benefits promised when the investment decision was made.

Q. If the Company is required to continue to maintain the benefits promised to customers in its 2017 IRP, what is the result on the Company's proposal?

A. It would mean that over 91 percent of the Company's renewable fleet would result in no difference in power cost recovery between the Company's proposal and the current PCAM structure. The Company's ability to forecast renewable generation accurately would have little direct impact on its power cost recovery issue.

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[30] *Ibid.* At 19.

Q. Why does Staff believe that QFs have no direct impact on the Company's power cost under-recovery issue?

A. Staff found in UE 375, the 2021 TAM, that the Company has over-forecast QF related power costs by roughly four percent on average.[31] QFs are not sources of zero cost energy; their under-generation can lead to power cost savings because cheaper power is available on the market or via Company-owned generation. Staff has implemented QF adjustment mechanisms for all Oregon regulated electric utilities because over-estimation of QF power harms customers.

Q. Does Staff believe that non-QF renewable power is a source of the Company's under-recovery?

A. No. Roughly 70 percent of the Company's non-QF renewable energy sources are set to come online in 2020. Of the renewables that were online prior to 2020, non-QFs make up only about twelve percent. Like QFs, these are not a source of "free energy." Due to their relatively small historical percentage of renewable energy, Staff does not believe they have been a source of under-recovery.

Q. Does Staff believe that the indirect impacts of renewables on PacifiCorp's system will have a detrimental impact on the Company's power cost recovery?

A. No. One of PacifiCorp's main arguments is that renewable generation results in many unforecastable transactions that are resulting in losses for the Company.

[31] UE 375, Staff/400, Zarate/10.

As Staff discussed previously, it remains to be seen if either the DA/RT or AURORA are insufficient to account for these purported issues. Staff also finds that the Company's narrative regarding additional transactions does not quite hold true.

Q. What is the issue with the Company's components of under-recovery analysis?

A. As Staff noted in opening testimony, there are a few issues with the Company's components of under-recovery analysis. The first is that the DA/RT adjustment was implemented in 2016, and designed to specifically address the issue of under-forecasted transaction prices and volumes. As such, any analysis pre-2016 regarding the relative recovery rates of power cost categories is no longer applicable. Staff further finds, that although there may be evidence that GRID over-optimizes and finds economic sales that the Company has yet to realize in actual operations, there is no evidence that the Company is experiencing added purchase cost transactions due to renewable generation variance.

Q. How did Staff come to the conclusion that added transactions are not driving under-recovery?

A. Staff provides Confidential Figure 2 from PAC/3000 for reference:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

1 Staff recreated the Company's figure, with purchases and sales broken out:

[BEGIN CONFIDENTIAL]

2 [redacted]

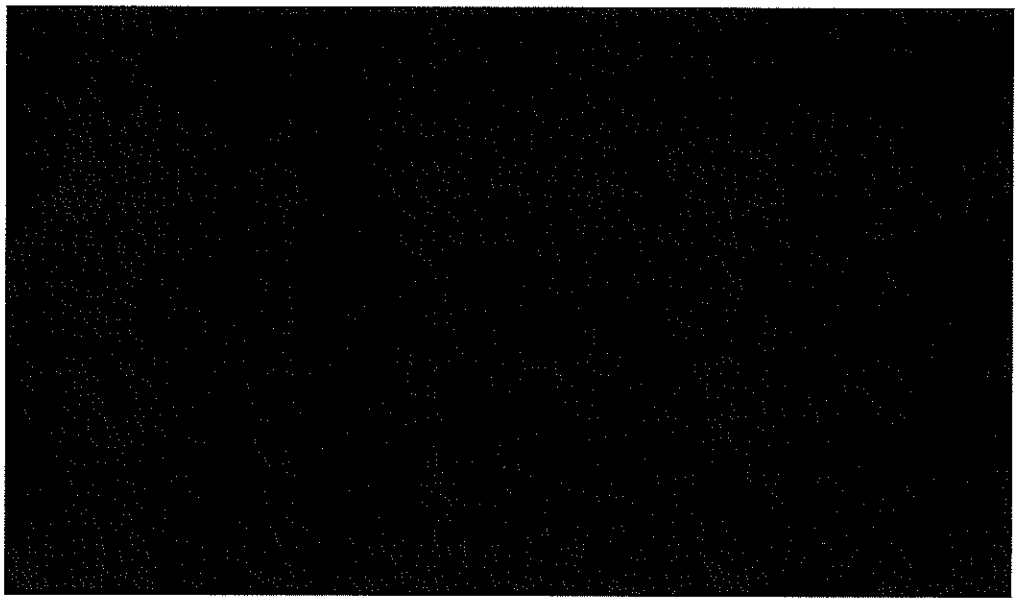
[END CONFIDENTIAL]

3 As evidenced by the above figure, system purchase costs have been over-
4 forecast every year since 2014. The data do not show that GRID has been
5 unable to forecast the added costs of purchases to balance the system, the
6 data show that GRID has been better at finding economic sales than the
7 Company has in actual operations. PacifiCorp argues that even when
8 renewables generate above expected, excess power may not be able to be
9 sold as economically as forecast, but this data does not necessarily point to
10 added transactions. If the annual renewable generation can be reasonably
11 forecast as the Company claims is possible, then even excess generation
12 leading to uneconomic sales would need to also include lower than expected

generation leading to uneconomic purchases. As the data show, this is simply not the case. Sales are being over-forecast while purchases are also being over-forecast. It is also not clear to Staff how unexpected over-generation would lead to less economic sales opportunities than expected, when the added generation was not forecast in the first place. It is more reasonable to assume that either PacifiCorp has been unable to efficiently optimize its system, or that GRID's perfect foresight is generally too good at economic dispatch.

To better illustrate the discrepancy in sales vs purchase accuracy, Staff provides the following two figures. They show the Company's forecasted vs actual sales and purchases excluding EIM transactions from 2017 to 2019 in dollars and MWhs.

[BEGIN CONFIDENTIAL]



[redacted]

[END CONFIDENTIAL]

The figures show that only one of the two market transaction types is largely inaccurate in the forecast. The added transactional costs are not apparent. A gross over-estimation of the sales benefit is. This is apparent in both the dollar and MWh metrics. It does not appear as though PacifiCorp performs numerous additional transactions at a loss, if that were the case the volume of trades would be largely the same or the Company would have higher actuals than is being realized. The Company's argument of additional transactions is only a theory unsupported by empirical evidence.

Q. Why did Staff exclude EIM from the above analysis?

A. There were several reasons that Staff excluded EIM transactional data from the analysis. The first is that only the dollar impact of the EIM is forecast in the TAM, transactional volumes are not. The second is that the Company accounts for EIM benefits in its actuals as a net amount, so imports and exports cancel each other out in a single line item. This is also why Staff only included the

most recent three years, because prior to this, EIM transactions were not a separate line item. The third is that GRID does not model the EIM, as the Company has framed its argument as largely an unforecastable modeling issue, the EIM is somewhat outside the scope, and the last reason is that the Company has made no argument that the EIM is part of the problem, in fact the Company has under-forecast EIM benefits every year they have been included in the forecast, including by a total of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from 2017-2019.[32]

Q. What does Staff believe that the data show?

A. As Staff previously mentioned, the most logical explanation for a gross over-estimation of sales is an over-optimized model or inefficient operation by the Company. Staff has already discussed the change from GRID to AURORA and the potential remedy for perfect foresight apparent in the new model's algorithm. As for the potential that PacifiCorp could simply be better at dispatching, Staff noted in its opening testimony of UE 375, that PacifiCorp's switch from a zonal model to a nodal pricing model for dispatch decisions could lead to more economic operation of its system.[33] In 2010, ERCOT changed from zonal to nodal dispatch and estimated consumer savings at $5.6 billion over the following 10 years.[34] Given that nodal pricing and a new dispatch model are imminent, it is premature to adopt a new power cost recovery

[32] See Staff/2402, Gibbens/1, PacifiCorp's confidential response to Staff DR No. 663. Under-forecasting a benefit leads to over-recovery, all else equal.
[33] UE 375, Staff/100, Gibbens/10.
[34] http://www.ercot.com/news/releases/show/349

mechanism that results in significant risk shifts to customers relative to the current structure. If in fact there are efficiencies to be had by better optimizing dispatch of the Company's fleet, the Commission should not compensate the Company for this under-recovery by shifting the cost of these inefficiencies onto ratepayers.

Q. Has PacifiCorp provided any evidence that the EIM, EDAM, or RA concerns will hinder the Company's ability to recover power costs?

A. No. Staff asked the Company why it believed these changes may further complicate the Company's ability to accurately forecast power costs, and the Company was unable to provide any reason. The Company instead stated that it has not concluded how any of these changes to the energy landscape in the West may impact net power cost recovery.[35]

Q. Does Staff have other concerns with the Company's analysis?

A. Yes, in opening testimony, Staff noted that the Company's analysis of monthly NPC deviation compared to net load variance was flawed. First, Staff showed that the relationship was highly dependent on a few data points. Staff did not argue that "these two months should be excluded from the analysis", as characterized by the Company.[36] Staff's point was that the Company was drawing conclusions from, and making substantial recommended changes based on a small number of non-standard outcomes. Second, the figure generally displayed that when the Company's net load variance actuals were

[35] See Staff/2401, PacifiCorp's responses to Staff DR Nos. 664-665 and Staff/2402, PacifiCorp's confidential response to Staff DR No 663.
[36] PAC/3000, Graves/22.

above forecast the Company under-recovered. This, as Staff pointed out, also meant that the Company was over-recovering fixed costs that are collected through variable charges generally. The Company responded that Staff was oversimplifying the problem by confusing net load variance with gross load variance.[37] Staff reviewed the Company's analysis further and believes that the Company is generally over-complicating the issue and drawing conclusions from the data that are unfounded. Below is the Company's updated figure included as confidential Figure 3 in PAC/3000, Graves/24.

[BEGIN CONFIDENTIAL]

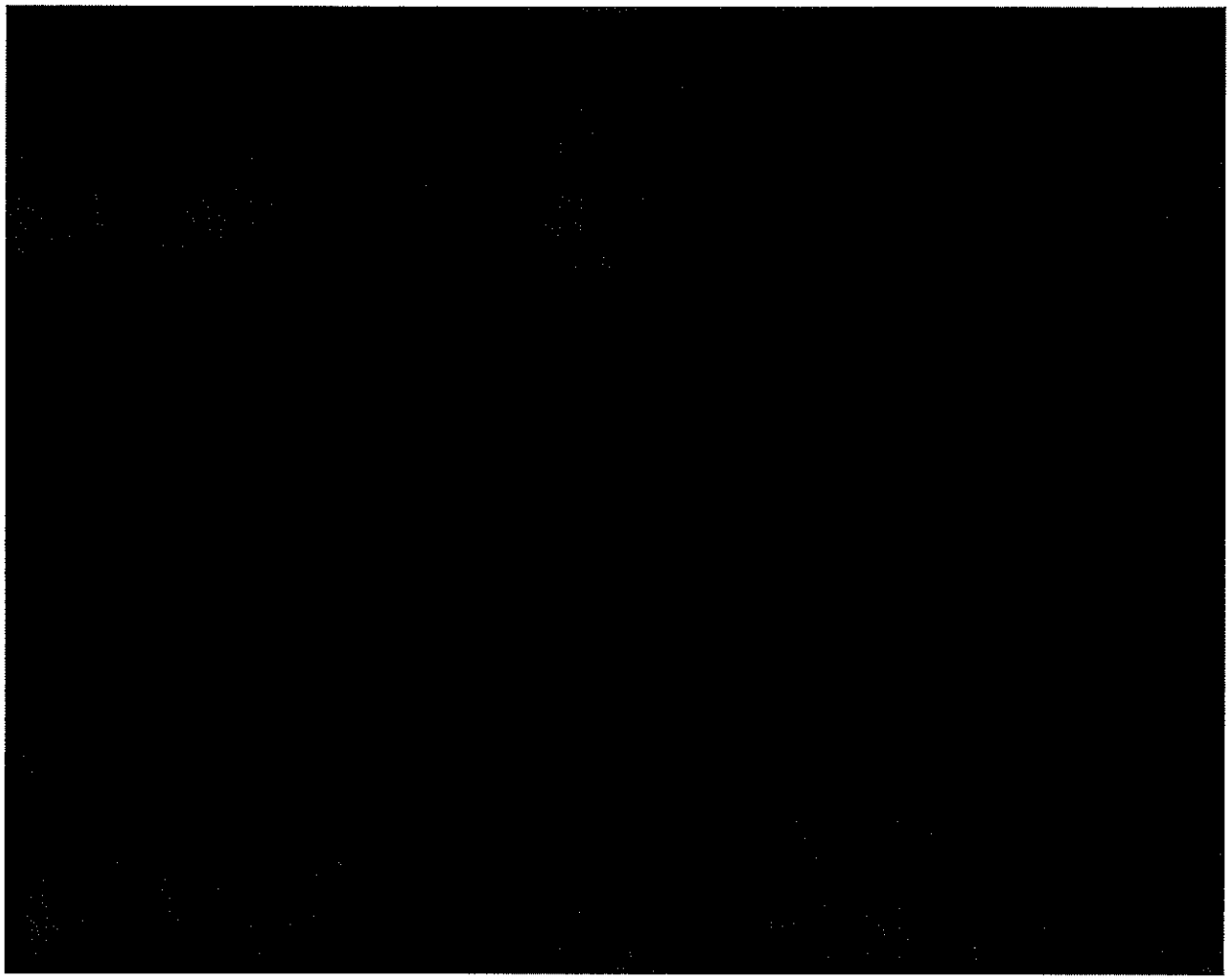
[37] PAC/3000, Graves/31, lines 11-16.

[redacted]

[END CONFIDENTIAL]

Staff has updated the Company's figure, to *only* include gross load variance.

[BEGIN CONFIDENTIAL]



[END CONFIDENTIAL]

The figure above shows that the same relationship with the same months appearing in almost the same position on the graph. In fact, the linear estimation shows a stronger relationship than when only considering net load. In the five months with the highest $/MWh deviation, gross load variance made

up roughly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the total net load variance on average.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The figure above shows the Company's same analysis when removing load entirely. **[BEGIN CONFIDENTIAL]**[redacted] **[END CONFIDENTIAL]** As Staff noted previously, when gross load is

above expected amounts, fixed cost recovery is generally above expected amounts as well. This supports Staff's finding and assertion that power cost recovery needs to be considered in a holistic manner, not in isolation.

In order to provide further clarification regarding the driving elements of the Company's under recovery, Staff ran simple regressions to identify which variables had the largest impact on the Company's recovery of power costs. Staff found that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** In terms of relative impact on the Company's recovery, load has a nearly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** times larger absolute impact on recovery than the other four elements (wind, hydro, long term sales and purchases) combined. Staff notes that as PacifiCorp's wind fleet grows, the impact of wind variance will as well, but at roughly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** times smaller than the impact load has on recovery, it has a ways to go.

Staff then used the data set to test the Company's hypothesis that NPC under-recovery was in fact increasing over time when accounting for differences in gross load. Staff found that the trend variable had a negative coefficient when all data was included (2014-2019), and a slightly positive coefficient when only data after DA/RT was included, however neither variable was remotely

[38] Staff/2403, Gibbens/1.

statistically significant.[39] This indicates that there is no statistical evidence to support the Company's assertion that NPC under-recovery is indeed increasing over time.

Alternative Analysis

Q. Although Staff's recommendation is that the PCAM remain unchanged, does Staff have any additional observations?

A. Staff first reiterates that it believes that the policy and structure of the PCAM remain sound, and does not find that changes to the PCAM are warranted, particularly for PacifiCorp in light of the unknown impact of PacifiCorp's new model and implementation of nodal pricing dispatch. Second, Staff does not believe that the PCAM should be used as a means to rectify a forecasting issue. That was not the intent of the PCAM. Finally, Staff notes that any changes to the PCAM policy or design may also be sought by PGE and Idaho Power, the impacts of which are not part of the record in this case. However, should the Commission decide that the PCAM should result in an adjustment more often (i.e, change NPC), Commission could consider these alternative steps discussed below:[40]

1. Reduce the size of the deadbands
2. Make deadbands symmetrical
3. Reduce earnings test "reasonableness" amount

[39] *Ibid.* At 2.
[40] Note: Staff is providing the Commission on ways to increase the number of adjustments resulting from a PCAM, as such the sharing percentages, which do not factor into the number of adjustments, are not considered.

4. Remove deadbands

Reduce size of deadbands

The deadbands have largely resulted in no adjustment regardless of the utility's earnings. The Commission did state that only unusual events should be considered as part of a PCAM adjustment but the earnings test and deadbands combined are resulting in even potentially unusual events from being included. The Company has simply not had a year where unusual events occurred and the Company simultaneously did not earn reasonable returns overall. No adjustments have occurred because the PCAM is operating as designed. As Staff has shown, the necessity for an earnings test is paramount to ensuring that ratepayers are not over-paying generally for the service they receive from the utility. It is fair and reasonable to expect the Company to experience under-recovery in one area, while it may be over-recovering in others. If a PCAM were to be designed to trigger more often, Staff would view the removal or alteration of what is "unusual" as less detrimental to the overall quality of the PCAM than removal or alteration to the earnings test. Revenue neutrality would be difficult to achieve should the Company continue to under-recover on a regular basis with a PCAM designed to trigger more often. However, if as an example the deadbands were cut in half, to $15 million and $7.5 million, the PCAM would have resulted in an adjustment in 5 of the 7 years (not including the earnings test, which I will cover). Deadbands of $20 and $10 million would result in the same three in seven we have currently, but the likelihood of adjustment would increase incrementally.

1 Make the Deadbands Symmetrical

2 Without fixing or at least improving the forecast, the PCAM is likely not going to
3 both result in adjustments and be revenue neutral. Making the deadbands
4 symmetrical would address at least one of the concerns raised by the
5 Company.[41] It would allow customers and shareholders to share costs and
6 risks. The downside, is that the PCAM will result in charges to customers much
7 more often than it provides refunds to customers.

8 Reduce earnings tests reasonableness amount

9 Because the Company's earnings have generally been relatively close to
10 authorized, only a single year (2018) would the PCAM have allowed an
11 adjustment if recovery was outside the deadbands. In order to make a PCAM
12 result in more adjustments, the level of reasonableness would likely need to be
13 altered. The Commission noted +/- 25 to 50 basis points was a general range
14 of reasonableness for a general rate case proceeding. However even a
15 reduction to 50 points would not have had an impact on the outcome of the
16 earnings test in the PCAM since 2013. A 25 basis point threshold would have
17 meant an earnings test adjustment in four of the seven years. This in
18 conjunction with a smaller symmetrical deadband could result in roughly a one
19 in four adjustment that the Commission opined about when installing the
20 PCAM.

[41] PAC/3000, Graves/7. Line 20.

1 Remove deadbands

2 An alternative approach to altering the reasonableness level of the earnings
3 test would be to remove the deadbands entirely and just leave any adjustment
4 to be limited only by the Company's overall earnings. As Staff noted, this would
5 have resulted in one PCAM adjustment thus far. It is unclear how this proposal
6 would impact the Companies incentives to keep power costs low. The
7 Commission would likely generally maintain an "unusual" standard, but would
8 also have the benefit of considering the Company's power cost recovery in
9 conjunction with its overall recovery. When load changes cause power cost
10 under-recovery, ratepayers may not be over-charged in a sense, as they would
11 have already paid their fair share of the Company's costs. The reason Staff
12 includes this at the bottom of the list of marginally acceptable changes to the
13 PCAM is because this change would result in a complete shift in what is
14 "unusual". The Company does not have materially different earnings in years
15 where "unusual events" would have triggered a PCAM adjustment based on
16 deadbands. Going back to 2011, the average under-recovery in power costs
17 for years where the Company had unreasonable earnings is $17.4 million, the
18 average under-recovery for years where the Company did not have
19 unreasonable earnings is $27 million.[42] Thus a PCAM without deadbands
20 would capture unusual events not specifically germane to power costs, they
21 would be events that affected the Company's overall recovery. This would

[42] This is based on ROE without Type 1 adjustments and excludes 2017 where the Company slightly under-earned on power costs but were above authorized ROE by 133 basis points.

mean that if a large customer left the system unexpectedly, customers may see a charge in the PCAM even though power costs were not adversely affected.

Conclusion

Q. What are the main arguments and points of consideration for the Commission?

A. Below is a list of the main points as Staff views them.

1. **The PCAM is functioning correctly based on the Commission's stated design criteria.**
   a. **The deadbands are capturing "unusual events"**. The deadbands were meant to only allow adjustments for unusual events, these events were assumed to occur roughly once in every four years. Since inception, the deadbands, in isolation, has resulted in an adjustment in two of six years.[43]
   b. **The PCAM has been revenue neutral**. This implies that the collections and refunds from the PCAM offset over-time. This does not mean, as the Company seems to imply, that the over/under collection of power costs should even out over-time.
   c. **The Company is not collecting/refunding under/over recovered power costs when its overall earnings are reasonable**. As Staff and CUB both showed in opening testimony, the Company's earnings are closer to authorized

[43] Three of seven if you include 2019 preliminary data.

ROE under the current PCAM construct than if the Company's proposal had been implemented.

d. **The PCAM has provided incentives for the Company to manage its power costs effectively.** The Company may in fact perform its due diligence in minimizing power costs under its proposal, but the incentive to minimize power costs is greater under the current construct. A prudence review may or may not be sufficient to ensure cost minimization. It relies on prudence disallowances, which are historically difficult to argue due to their asymmetry of information and retroactive nature. The current structure includes both carrots and sticks to incent the Company.

2. The Company has generally under-recovered power costs since 2008.

a. The PCAM has not resulted in any adjustments to power costs, as Staff noted in opening testimony this is due in combination to the deadbands and earnings test.

b. The Commission has previously stated that changes to the forecast are the optimal solution to chronic under-recovery, but the Company has been yet unable to fully resolve the apparent issue. The DA/RT adjustment has reduced the size of the issue, however its actual impact on the ability to appropriately forecast power costs is still unknown.

c. Should the Commission believe that a the PCAM should result in adjustments at least once in every seven years, Staff strongly recommends alterations to the current structure, not wholesale abandonment of the philosophy underlying the PCAM.

3. **The Company is changing forecasting models for all power costs moving forward.**

a. The Company has not, and cannot prove that a new, more sophisticated model will not resolve the under-recovery. The Company just began implementing the model, it has little to no operational experience with it. No one knows what its impact will be. This fact, coupled with Staff's belief that the current PCAM structure better aligns customer and shareholder incentive, furthers Staff's alternative recommendation for incremental change in lieu of wholesale abandonment.

4. **The Company's analysis of actual vs forecasted power cost data is flawed.**

a. The Company did not provide the Commission with a clear representation of the underlying issue with the Company's under-recovery. Staff believes this may be because it points to potential inefficiencies apparent in the Company's operations. At best, it is an issue that a new model may be able to handle.

b. The narrative that balancing costs are not able to be forecasted in linear models is not apparent in the data. The TAM base power costs over-forecast system purchase costs.

5. **The Company has argued that "new circumstances" warrant dollar-for-dollar recovery of power costs before.**
   a. Most of the Company's current arguments have a corollary to the original decision made by the Commission.
   b. New renewables should not have any material direct impact on power cost recovery.
      i. The Company has already agreed to provide customers with the promised benefit of almost its entire wind fleet, which makes up the vast majority of its in house renewable portfolio.
      ii. PURPA contracts have historically been over-forecast and harmed customers.
      iii. Added transaction analysis is flawed as previously noted.
6. **The Company is relying on too few years or datapoints.**
   a. **The GRID backcast analysis does not prove further improvements are not possible**
      i. The analysis was done on the two lowest variance PCAM years in the last twelve years. The 2017, the variance between actual and forecast was only improved by 0.1

1 percent using actuals compared to the forecasted
2 amounts.
3 b. **DA/RT may be a fix.**
4 i. Power cost under-recovery has not been increasing
5 overtime. The Company's recovery of power costs since
6 the implementation of the DA/RT adjustment has been
7 closer to full recovery than any three or four year period
8 since 2008.
9 ii. The Company has repeatedly claimed that it only over-
10 recovered power costs due to a one-time adjustment due
11 to the abandonment of the Joy Longwall, however even
12 without adjusting for the Joy Longwall, the Company still
13 over-recovered power costs in that year. That means
14 since DA/RT the company has over-recovered one in
15 three (or four if you count 2019 preliminary data) years.
16 The odds of getting a single heads in four flips of a coin is
17 twenty-five percent. It is impossible to say that the current
18 PCAM, with DA/RT, results in chronic under-recovery.
19 c. **Market price/Load correlation is based on a small number**
20 **of data points.**
21 i. As Staff showed in opening testimony, the entire
22 relationship is based on a few months of actuals. It could

be a sign of an actual relationship, or it could be random noise. Prudent data scientists wait for more data.

ii. The data that are available point to the fact that gross load is driving the vast majority of the relationship. It is no surprise that as load goes up beyond expected levels, power costs go up beyond expected levels. Load has an offsetting effect on the Company's overall recovery of costs as the majority of fixed costs are recovered through variable rates.

d. **The data ultimately tell a different story than the Company is arguing.**

i. The data show that the over-forecasting of sales are potentially driving the under-recovery. The Company's narrative would predict an equal frequency of purchase and sale forecasting error or at best a relatively even distribution of errors. It is not that GRID or AURORA are not sophisticated enough to model "numerous and costly balancing transactions"[44], it is that GRID thus far has been over zealous in forecasting sales. There is no evidence that added transactions are the root of the issue. Perfect foresight may be the cause, but AURORA may be the fix. This means that added renewables, more

[44] PAC/3000, Graves/2, line 3 and 4.

sophisticated dispatching systems, greater reliance on natural gas, and a myriad of other reasons cited by the Company are not indicative of the causes of under-recovery.

ii. Gross load variance, not net load variance is another driving factor for under-recovery. The main issue is not wind, hydro, long term purchase and sales; these have small, insignificant impacts on recovery of power costs. Load deviations, particularly under-forecasted ones are shown to be a source of the recovery issue. This comports somewhat to the Company's argument that these may be unpredictable and costly, but it is not a new problem, or a significantly worsening problem, and it is an issue with an equal offset to the Company's overall recovery.

Conclusion

The Company tells a story that is plagued by insufficient data and unfounded conclusions. The Company has historically under-recovered power costs. The PCAM has not resulted in an adjustment. The Company's overall earnings, the ultimate measure of the fairness of the relationship between the customer and the Company is better under the current construct than the Company's proposal. Staff recommends no changes because it is too soon to see if the proper correction for chronic under-recovery has or will be implemented. Staff

1 would support a review of the PCAM structure in four or five years, and feels
2 comfortable making that recommendation because the Company is still earning
3 at a reasonable rate. However, should the Commission be inclined to make a
4 change, with the limited information we have at our disposal, Staff
5 recommends incremental changes, which maintain the essence and incentives
6 of the previous Commission design.
7 **Q. Does this conclude your testimony?**
8 A. Yes.

CASE: UE 374
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2401
PacifiCorp Responses to Staff DR Nos. 664, 665, 667

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

UE 374/PacifiCorp
July 6, 2020
OPUC Data Request 664

OPUC Data Request 664

APCA/ Power Cost Recovery
Regarding PAC/2000, Wilding/61, lines 7: Please provide a narrative description of why the Company believes resource adequacy (RA) concerns may result in further complications to NPC recovery. Please include a discussion of the Company's RA related actions when considering the "Western Resource Adequacy Evaluation" included as Appendix J of the Company's updated 2019 IRP which notes that "potential shortfalls in Planning Reserve Margin are small and 8-9 years distant."

Response to OPUC Data Request 664

Referencing the reply testimony of Michael G. Wilding, page 61, line 7:
Mr. Wilding cites "renewed discussions on resource adequacy" as evidence of potential future changes to the energy landscape in the West along with changes that have already incurred since the power cost adjustment mechanism was implemented. The Company has not concluded how "renewed discussions on resource adequacy" may impact net power costs recovery.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

UE 374/PacifiCorp
July 6, 2020
OPUC Data Request 665

OPUC Data Request 665

APCA/ Power Cost Recovery
Regarding PAC/2000, Wilding/61, lines 7 and 8: Please provide the evidence or analysis supporting the Company's conclusion that the implementation of a day-ahead energy market may result in further complications to NPC recovery.

Response to OPUC Data Request 665

Referencing the reply testimony of Michael G. Wilding, page 61, line 7 and 8, Mr. Wilding cites "a day-ahead energy market" as evidence of potential future changes to the energy landscape in the West along with changes that have already incurred since the power cost adjustment mechanism was implemented. The Company has not concluded how "a day-ahead energy market" may impact net power costs recovery.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

OPUC Data Request 667

APCA/ Power Cost Recovery
Regarding PAC/2000, Wilding/67, line 8 and 9 and the Company's expected switch to AURORA for NPC forecasting:

(a) Please provide evidence that the AURORA nodal model has perfect foresight, specifically as it relates to the ability to optimize every hour for the next hour. Is there any option which may allow the model to not have perfect foresight?

(b) Is the Company expected to utilize AURORA to simulate market prices or will the Company continue the use of its OFPC in NPC forecasts?

(c) Has the Company completed purchase of, and implementation of the AURORA model?

(d) Please include any known issues or concerns which the Company is expected to face when transitioning from GRID to AURORA for power cost forecasting.

Response to OPUC Data Request 667

(a) Below is a description of AURORA's commitment and dispatch decision making process and, as a corollary, its perfect foresight. This description is provided by Energy Exemplar, the developer and owner of the AURORA production cost simulation software:

(1) Please provide evidence that the AURORA nodal model has perfect foresight, specifically as it relates to the ability to optimize every hour for the next hour.

The commitment optimization method in Aurora uses a mixed-integer linear program (MIP) to determine the hourly unit commitment pattern. It is a robust methodology that uses all information about the system for the time period being solved to find a solution that is guaranteed to be optimal up to an input tolerance level. The commitment optimization method will generally give better results than the traditional commitment method in terms of total system production cost, adherence to all commitment constraints, and incorporation of all system characteristics in the commitment decisions (e.g. network topology, outages, Operating Rules, etc.). The higher precision generally comes at the expense of longer run times over the traditional commitment method.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

The optimization solves the commitment patterns one day at a time with a mathematical program. Each day that is solved will include data from a user specified number of additional days to ensure that the commitment decisions adequately take into account the system constraints for upcoming hours. All information about the system is considered in the commitment decisions including demand, fuel prices, resource costs, transmission availability, and operating rules. The objective function is the minimization of system cost which includes resource start and shutdown costs, zonal wheeling charges, and all standard components of resource incremental costs. The commitment decisions use all the same information as the LP dispatch including hourly demand, zonal transfer capacities, resource availability, multi-link limits, and resource segment differentiation. The Minimum up and down times are modeled as hard constraints and minimum capacities will always be honored on commitment units. Additional constraints are automatically added for resource dependency inputs, RMR rules, and pool spinning reserve requirements.

(2) Is there any option which may allow the model to not have perfect foresight?

There are options for introducing forecast error into an Aurora simulation. The Dispatch Uncertainty Table and Forecast Error columns in the Zone Definition table allow you to model uncertainty between commitment and dispatch.

(b) The Company will continue to use its official forward price curve in producing its net power costs.

(c) The Company has purchased the AURORA production cost software and is in the process of implementing.

(d) Transitioning to AURORA will enable the Company to optimize unit commitment and to better model battery storage, emission costs, regulating reserves, hydro operations, and jurisdictional marginal costs. Moreover, AURORA like the Generation and Regulation Initiative Decision Tool is a linear program, and subject to the same operating and transmission constraints, with which the Company has years of experience. However, transitioning to a new model requires user education as to logistics, modeling conventions, reporting of results, and interpretation of results—to name a few.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

CASE: UE 374
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2402
PacifiCorp Confidential Response to Staff DR No. 663

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

UE 374/PacifiCorp
July 7, 2020
OPUC Data Request 663

OPUC Data Request 663

APCA/ Power Cost Recovery
Regarding PAC/2000, Wilding/61, lines 6 to 7: Please indicate by year, the difference between EIM forecasted benefits and EIM actual benefits. In light of this, does PacifiCorp believe the EIM is contributing to under-recovery of NPC? Why or why not?

Response to OPUC Data Request 663

Please refer to Confidential Attachment OPUC 663. The Company has not made the conclusion that energy imbalance market benefits are contributing to the under-recovery of net power costs (NPC) since the under-recovery of NPC is a systematic issue and cannot be evaluated based on one single item included in NPC.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

Staff Exhibit 2402 Page 2 is Confidential and Subject to Protective Order No. 20-040

CASE: UE 374
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2403
Drivers of Power Cost Recovery Regression Analysis

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Staff Exhibit 2403 is Confidential and Subject to Protective Order No. 20-040

CASE: UE 374
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2500

Rebuttal Testimony

July 24, 2020

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Heather Cohen. I am a Senior Utility Analyst employed in the
3 Energy Rates, Finance and Audit Division of the Public Utility Commission of
4 Oregon (OPUC). My business address is 201 High Street SE., Suite 100,
5 Salem, Oregon 97301.

6 **Q. Have you previously provided testimony in this case?**

7 A. Yes, please see Staff Exhibit 400. In addition to the adjustments discussed
8 here, I also provided an expense adjustment in the amount of ($1.4 million) for
9 Customer Accounts and Services.[1]

10 **Q. What is the purpose of your testimony?**

11 A. To rebut portions of the testimony of Shelley McCoy (PAC/3100).

12 **Q. Did you prepare any exhibits for this testimony?**

13 A. Yes. I prepared Staff Exhibit 2501, consisting of 58 pages as well as Staff
14 Exhibit 2502, consisting of 8 pages.

15 **Q. How is your testimony organized?**

16 A. My testimony is organized as follows:

17 Issue 1, Wages and Salaries 2
18 Issue 2, Incentives 12
19 Issue 3, Advertising..... 19

.[1] See Staff Exhibit 400, Staff Opening Testimony, See Staff electronic Workpaper UE 374 Exhibit 400 Issue 5 Customer Accounts and Service.

ISSUE 1, WAGES AND SALARIES

Q. Please summarize Staff's position on Wages and Salaries in its Opening Testimony.

A. In keeping with Commission policy, Staff used a three-year wage and salary model to estimate expenses for non-union wages and salaries, tying payroll increases in historic base year to rate of inflation using the All-Urban CPI.[2],[3] Union wages were tied to negotiated wage increases according to Commission policy.[4] On a Total Company basis, the Company's test year ending December 31, 2021 includes $464 million in wages and salaries (base pay) and $84 million in overtime.[5] For non-union employees, Staff escalated the wages and salaries from the 2018 historical base to the test year using the All-Urban CPI, consistent with the W&S model using inflation rates of 1.8 percent, 1.8 percent and 1.7 percent for 2019, 2020 and 2021, respectively. Staff escalated union employees' salary by 4.3 percent, 2.82 percent, and 2.63 percent for 2019, 2020, and 2021.[6] Because there were nine unions impacted with varying dates of pay increases, Staff used the calendar year average for all unions to escalate union pay.[7]

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[2] See e.g., *In the Matter of PacifiCorp*, OPUC Docket UE 116, Order No. 01-787 at 40 (September 7, 2001).

[3] See Order 01-787 at 40; In the Matter of Northwest Natural, OPUC Docket UG 132, Order No. 99-697 at 43 (November 12, 1999); *In the Matter of PGE*, OPUC Docket UE 102, Order 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, OPUC Docket UE 88, Order No. 95-322 at10 (March 29, 1995).

[4] See Order No. 99-697 at 43.

[5] Staff/2501, PAC Response to Staff DR 92, 123.

[6] See Staff electronic Workpaper UE 374 Exhibit 2500 Issue 1 Wage and Salary Model CONF tab Union Increases.

[7] Ibid.

After applying the sharing principle, wherein Staff allows the Company to share 50/50 the lesser of the difference between the projections or a 10 percent band around Staff's projection, and applying the 28.3 Oregon allocation percentage, Staff recommended a reduction of the test year salaries and wages by $1.6 million, overtime by $1.5 million and small reductions to payroll taxes and depreciation ($776 thousand and $107 thousand) respectively.[8] Incentives will be discussed in a separate section.

Q. What is Staff's response to the Company's Reply Testimony that Staff did not use the correct baseline in its Wage and Salary model?

A. The Company's preferred baseline data was that for the 12-month period ending June 2019 and took issue with Staff's use of calendar year 2018 data as it was "6 months older" than the data used by the Company and did not capture the full extent of 2018 wage increases.[9] First, the Wage and Salary model does not necessarily use the Company's base year as its baseline. The Commission's preference is to use a 3-year model "with the model base year being three years prior to the Test Year."[10] In multiple rate cases, a base year that was three years prior to the test year has been used: UG 366 used 2017 historical wages to project a 2020 test year, UG 347 used 2015 historical wages to project a 2018 test year while UG 344 used 2016 wages to project a

[8] See Staff Exhibit 400, Staff Opening Testimony
[9] See PAC/3100 McCoy at 11.
[10] In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149, UE 116, Order 01-787 at 39-40.

2019 test year.[11] In addition to forecasted data in its 2021 test year (December 2020 through December 2021), the Company provided data for 2019, 2018, 2017 and 2016 for which Staff used 2018 as its model base year. The purpose of a model is to provide information that can reliably be used to estimate expenses for wages and salaries and 2018 was the most reliable data available to Staff.[12] Moreover, the Company's base year of June 2018 to June 2019 seems an odd choice given its test year period of December 2020 – December 2021. It is interesting that while Company seems unduly concerned over Staff's six month lagged data, it apparently has no such issue over the 18-month gap between its base year and Test year – a time period long enough for there to be to significant changes in the employment market. Finally, as to Company's assertion that Staff's timeline fails to account for all of its 2019 wage increases, it is a moot point since Staff uses the All Urban CPI to estimate wage and salary increases, not Company's escalation factors.

Q. What is Staff's response to the Company's Reply Testimony that Staff did not use the correct union increases in its Wage and Salary model?

A. First, Staff made a good faith effort in obtaining reliable union information from the Company. When querying union FTEs, the Company responded that it did not "maintain wages and full time equivalent information by employee groups listed (NEO, Exempt, Non-Exempt, Non-Union and Union)" and acknowledged

[11] UG 347 Opening Testimony/Staff/100, Gardner at 17, See Staff Workpaper UG 366 Exh 100 Wages and Salary & Incentive MG, UG 344 Opening Testimony/Staff/100, Gardner at 32.
[12] In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149, UE 116, Order 01-787 at 38.

1 "costs associated with wages, salaries and payroll taxes are charged to
2 numerous accounts and to acquire such data on an Oregon basis would result
3 in copious time."[13] When Staff asked for union contracts for Oregon unions,
4 Company responded that also was not possible since "labor costs are system
5 allocated" and responded with information for all PacifiCorp unions, not just
6 those that represent Oregon-based employees.[14] Finally, when Staff asked for
7 Oregon union increases per year for 2017 through 2020, the Company
8 maintained it could not do so and again provided information for all PacifiCorp
9 unions.[15] In preparation for this testimony, Staff asked once again for union
10 increases for Oregon jurisdiction and PacifiCorp failed to provide the
11 information.[16] The Company has repeatedly griped about the onerous nature
12 of Staff's data requests – requests which are similar to those filed in all active
13 rate cases. The Commission did not compel PacifiCorp to simultaneously file
14 rate cases in all of its jurisdictions; and it will not be shortchanged by
15 Company's obstructionist methods. The Company invests heavily in a
16 sophisticated allocation cost model, partially at customer's expense, so Staff
17 expects that such information, or even an estimate, could be provided to
18 parties.[17] Other multi-jurisdictional utilities operating in Oregon have been able
19 to provide similar information when requested, and Staff believes it is more

[13] See Staff/2501, PAC Response to DR 178.
[14] See Staff/2501, PAC Response to DR 241.
[15] See Staff/2501, PAC Response to DR 242.
[16] See Staff/2501, PAC Response to DR 696.
[17] PacifiCorp Allocation Protocol Application.
https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/idaho/filings/case-no-pac-e-19-20/12-3-19-application-and-direct-testimony/2020_PacifiCorp_Inter-Jurisdictional_Allocation_Protocol_Application.pdf.

than reasonable to request the same level of detailed information from PacifiCorp. Staff is deeply concerned at the Company's lack of accountability in providing an evidentiary basis for costs allocated to Oregon, due in part to the activities in other jurisdictions that are within its control. However, Staff is open to an adjustment should Company provide a reasonable estimate of its Oregon-specific increases.

Second, as mentioned in Company's testimony, because of the sharing principle which allows the Company to share 50/50 of the difference between projections, an initial difference of $1.3 million in union wages was reduced to $648 thousand (Total Company) while an initial difference of $7.7 million in union overtime was reduced to $4 million (Total Company).[18] After adjusting these numbers for the Oregon jurisdiction, Company's union wages adjustment was reduced to $184 thousand and its overtime was reduced to $1.1 million. For scale, this means that Staff's adjustment amounts to 0.271 percent of Company's Test Year Oregon Union Wages and roughly 5 percent of its Test Year Union Overtime amount.

	Total Company		Oregon (28.3%)	
	Wages and Salary Test Year	OT Test Year	Wages and Salary Test Year	OT Test Year
Union	239,912,359	81,796,192	67,895,198	23,148,322
Staff Adjustment	648,469	4,026,521	184,003	1,142,525
Adjustment as % of Test Year			0.271%	4.936%

[18] See Staff electronic Workpaper UE 374 Exhibit 2500 Issue 1 Wage and Salary Model CONF

1 Lastly, the Company admitted in its own testimony to "mistakenly using
2 incorrect percentages for the increases for the IBEW 57 union groups" and
3 included a correction which reduced its Oregon-allocated amounts by $875
4 thousand.[19] Considering Staff has repeatedly been given no information or
5 incorrect information, Staff's adjustment is reasonable when compared to the
6 Company's own reduction.

7 **Q. What is Staff's response to the Company's Reply Testimony regarding**
8 **escalation?**

9 A. PacifiCorp believes the inflation model used by Staff should no longer rely on
10 the All Urban CPI but instead industry benchmarking sources such as World at
11 Work, a membership-only commissioned resource. World at Work issues
12 yearly surveys which close in May and publishes the results of approximately
13 6,000 responders in its Salary Budget Surveys.[20] Unlike the CPI which is
14 updated quarterly, World at Work releases data once a year (May 2019 for its
15 2020 forecast, for example). Its results do not show any indication of an
16 economic downturn as its optimistic escalation figures of 3.2 and 3.3 percent
17 for 2019 and 2020 (see illustration below) do not seem to match current
18 economic realities.[21]

[19] See PAC/3100 McCoy at 20.
[20] Staff/2501, PAC Response to DR 99
[21] Ibid.

UNITED STATES

Salary Budget Increases, by Type of Increase

	Actual 2018		Projected 2019		Actual 2019		Projected 2020	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
General Increase/COLA	1.5%	2.0%	1.8%	2.0%	1.7%	2.0%	2.0%	2.5%
Merit Increase	2.8%	3.0%	2.9%	3.0%	2.9%	3.0%	3.0%	3.0%
Other Increase	0.8%	0.5%	0.9%	0.5%	0.9%	0.5%	1.0%	0.8%
Total Increase	**3.1%**	**3.0%**	**3.2%**	**3.0%**	**3.2%**	**3.0%**	**3.3%**	**3.0%**

The use of a timely economic tool is particularly salient today when we are in what the Wall Street Journal dubs "most tumultuous period in recent memory" due to a global pandemic, widespread unemployment, nationwide protests and a roller-coaster stock market.[22] This period, undocumented by such sources as "World at Work," has seen a 48 percent increase in filings for corporate bankruptcy protection compared to a year ago, and a 19.1 million decline in payroll jobs compared to six months ago along with the closure of 140 thousand businesses.[23] Moreover, many economists feel that the worst is yet to come as emergency benefits (stimulus checks combined with more generous unemployment benefits) that lifted U.S. consumer incomes by a record 10.8 percent are set to expire at the end of July.[24] The Federal Reserve warns that without sizeable fiscal support, the country faces a potential double-dip in economic activity.[25] Bank executives are reporting dire outcomes as well claiming, "People are scared, and they are responding by both banking their

[22] Six Months that Shook the World, Wall Street Journal: June 27, 2020.
[23] Ibid.
[24] Marte, J and A Saphir. A Cash Cliff Spells Trouble for U.S. Unemployed, and Everyone Else, Reuters Business News: June 29, 2020.
[25] Timiraos, Nick. Key Fed Official Warns of Double Dip, Wall Street Journal: July 17, 2020.

cash and basically prefunding their borrowing needs as much as they can."[26] The U.S. banking system has added $2.2 trillion in deposits so far this year, triple any other six-month period on record.[27] Given these issues at the forefront, tying rates to intermittent salary studies does not inspire confidence.

The Company has also suggested the use of wage inflator such as the US Average Wage Rate to estimate rises in wages.[28] However, in longstanding precedent, the Commission has validated the use of the CPI in tying payroll increases to the rate of inflation.[29] The Commission's Order decided this very issue in UG 132:

> The model incorporates actual market-based data by using, as a starting point, actual historic wages. We also agree with Staffs use of the All Urban CPI index to adjust historic wages and salaries. **Adjusting payroll levels by changes in inflation provides the employees the same real level of compensation as in the base year, and provides an incentive to companies to minimize labor costs**. Contrary to the assertions by NW Natural, **local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey.** Moreover, Staffs method of sharing the difference between payroll projections equally between ratepayers and shareholders also allows NW Natural some ability to increase wages above the rate of inflation in response to changes in market conditions without allowing unchecked escalation.[30]

Similarly, when PGE faulted Staff for not using a market-based model, one which also used annual surveys from multiple sources to determine competitive base pay, the Commission found "the three-year wage and salary

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[26] Benoit, David. Banks Report Wide Section of Business in U.S. Is Hurting, Wall Street Journal, July 20, 2020.
[27] Ibid.
[28] See PAC/3100 McCoy at 13.
[29] See Order 01-787 at 40; In the Matter of Northwest Natural, OPUC Docket UG 132, Order No. 99-697 at 43 (November 12, 1999); *In the Matter of PGE*, OPUC Docket UE 102, Order 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, OPUC Docket UE 88, Order No. 95-322 at10 (March 29, 1995).
[30] See Order No. 99-697 at 43.

formula more reasonable than PGE's approach" and noted the Commission's reliance on Staff's model "for over ten years to monitor energy utilities' wages and salaries for both general rate cases and earnings tests associated with deferred accounting."[31]

While Staff has used an inflation rate from March 2020 to determine Company's escalation, the Oregon Department of Revenue has recently updated its All Urban CPI forecast as of June. This new rate will be used in all adjustments going forward.

Year	March 2020 Forecast[32]	June 2020 Forecast[33]
2019	1.8	1.8
2020	1.8	0.7
2021	1.7	2.1

As pictured above, a steep drop in 2020, from 1.8 to 0.7 percent, is forecast. This is in keeping with a "catastrophic" employment report released in April which estimated 267,000 in job losses for Oregon and a state unemployment rate of 14.2 percent.[34] Interestingly, the Company's benchmark data showed no such decrease at a time when the Congressional Budget Office predicts the "economy's recovery from the downturn related to coronavirus responses to drag on through the end of next year, as investment collapses and the labor

[31] See *In the Matter of PGE*, UE 88, Order No. 95-322 at 10 (March 29, 1995).
[32] See Exhibit Staff/403, Excerpts from OR Office of Economic Analysis, All Urban CPI Oregon Economic & Revenue Forecast March 2020, Volume XL, No. 1, Table A.4, page 41.
[33] See Staff Exhibit 2502, Oregon Economic & Revenue Forecast June 2020, Volume XL, No. 2, Table A.4, page 37. https://www.oregon.gov/das/OEA/Documents/forecast0620.pdf
[34] Ibid, Economic Outlook, 3.

1 market experiences its sharpest deterioration since the 1930s."[35],[36] The CPI
2 remains the most widely used measure of inflation, linked to federal income
3 tax rates, eligibility for public assistance, and cost of living adjustments to over
4 50 million Social Security beneficiaries, military and Federal Civil Service
5 retirees.[37] Thus, Staff finds the All Urban CPI a better barometer than
6 Company's benchmarking studies. Once again, Staff is not compelling
7 PacifiCorp to pay its employees a certain way. Staff is simply drawing a firm
8 boundary on what ratepayers, many of whom are likely struggling financially,
9 will contribute and a measure which is tied to the pay increases for over $50
10 million Americans is sound.
11
12

[35] See PAC/3100 McCoy at 13.
[36] Kiernan, Paul. Wall Street Journal. U.S. Economic Recovery Will Drag On Through Next Year, CBO Says, May 19, 2020.
[37] Bureau of Labor Statistics: Consumer Price Index Frequently Asked Questions: https://www.bls.gov/cpi/questions-and-answers.htm

ISSUE 2, INCENTIVES

Q. Please summarize Staff's position on Incentives in its Opening Testimony.

A. Staff's position relies on Commission policy which traditionally disallows 100 percent of officers' incentives and a portion of non-officer employee incentives. Non-officer incentives are disallowed at 50 percent if they are based on non-financial metrics and 75 percent if the incentives are based on financial performance measures. The Commission's policy appropriately matches costs and benefits as officers' incentives hinge on meeting shareholders' financial expectations. The policy as it relates to non-officers is more flexible and recognizes that both customers and shareholders benefit from high-achieving employees whose daily jobs impact both customers' quality of service and the Company's bottom line. Union bonuses are treated in the same manner as non-union bonuses.[38] Staff recommends a reduction in the Company's Oregon test year incentives of ($4.7) million allocated as ($3 million) O&M and ($1.7 million) capital.[39] Staff also proposes disallowing ($535 thousand) of officer incentives capitalized in plant based on 2015-2020 data.[40] The amount of incentives in plant was adjusted from $534 thousand from opening testimony to $535 thousand based upon Company's 2019 update.[41]

Q. Does Company agree with Staff's methodology?

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[38] See Order No. 99-697 at 44-45; Order No. 99-033 at 62.
[39] See Staff Exhibit 400, Staff Opening Testimony
[40] See Staff electronic Workpaper UE 374 Staff Exhibit 2500 Issue 1 Wage and Salary Model CONF tab Plant Incentives
[41] Staff/2501, PAC Response to DR 676.

A. No. The Company seeks full recovery of its $9.5 million of pay-at-risk on an Oregon jurisdictional basis.[42] The Company also rejects Staff's reduction of incentives capitalized in plant ($535 thousand).[43] PacifiCorp states at-risk pay, or incentives, are necessary to motivate strong performance, increase productivity and improve retention.[44]

Q. How does Staff respond to Company's rebuttal regarding all other Incentives?

Commission Policy

The Commission's policy disallowing portions of incentives for rate-making purposes is well documented in past orders and Staff practice. Company claims its pay-at-risk results in market-level compensation.[45] As noted in the Commission's disposition in Order 97-171, whether compensation as a whole is reasonable is measured against the market and is a distinct issue from whether customers should pay for incentives in rates.

> Because its compensation is reasonable compared to the market, USWC concludes that its expense for management and executive bonuses is reasonable. USWC conflates two separate issues. The level of overall compensation is reasonable compared to the market. **That does not determine whether it is reasonable to ask ratepayers to fund bonuses with the declared goals of USWC's incentive plans**.[46]

[42] See PAC/3100 McCoy at 14.
[43] See Staff electronic Workpaper UE 374 Exhibit 2500 Issue 1 Wage and Salary Model CONF tab Plant Incentives
[44] See PAC/3100 McCoy at 15.
[45] Ibid.
[46] *In the Matter of the Application of US WEST Communications, Inc., for an Increase in Revenues,* UT 125, Order No. *97-171.*

PacifiCorp argues that pay-at-risk actually increases customer benefits.[47] The fact that incentives could benefit both shareholders and customers is not at odds with Commission policy. That is evident in the sharing methodology the Commission policy sets forth. Rather it is the metrics, goals, and targets the plan is based upon that give rise to the disallowance.

In Docket No. UT 125, Staff asserted that bonuses paid by US West Communications (USWC) under certain plans were based on achieving financial, business, and corporate goals. The USWC plans in question included the following metrics (1) Earnings before Interest Taxes, Depreciation, and Amortization (EBITDA); (2) USWC Net Income; and (3) Business Unit Results & Strategic Measures, Customer Service, Customer Loyalty, increase in USWC stock price, and stock dividend growth. Staff proposed to disallow all of the bonuses associated with these plans. In the disposition of this issue, the Commission stated as follows in Order 97-171:

> We note that our disallowance is not based on the manner in which compensation is administered but on the purpose for which the bonuses are awarded. We also note that this conclusion does not prevent USWC from paying bonuses; it merely dictates that bonuses be paid from funds that would go to shareholders, not from funds provided by ratepayers. Therefore, we do not believe that the resolution of this issue places USWC at a competitive disadvantage.* * * If in a future rate case USWC submits employee incentive plans with goals that would benefit both ratepayers and shareholders, we will include those expenditures in revenue requirement.[48]

[47] See PAC/3100 McCoy at 15.
[48] Ibid.

The Commission does not dictate an appropriate compensation policy for any of the regulated companies. Rather, the Commission allows in rates those costs that result in just and reasonable rates for customers. The Commission's disallowance of certain incentive plans reflects the fact that customers and shareholders benefit in different proportions to the plan. Because the Commission applies the same policy across all of the regulated companies under its regulatory authority, it does not set them at a competitive disadvantage from each other.

The intent of Incentives

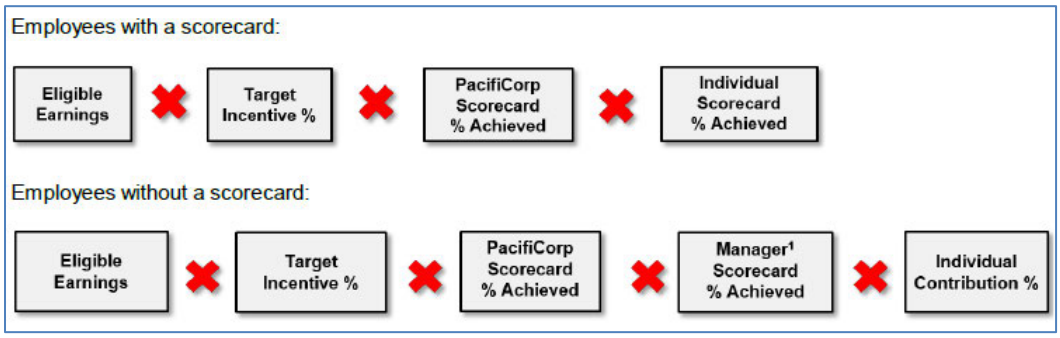
Because the Company removes its Executive Long Term Incentive Plan and Supplemental Executive Retirement Plan from its Test Year, it demands the Commission pay for the rest of its Executive Incentives in their entirety. PacifiCorp argues that executive incentives should be fully recovered because they are "tied to these same metrics from which customers benefit"[49] However, the Company's 10k establishes that the compensation committee, comprised solely of the Chairman and CEO, assess executive performance and determine compensation in a way that is "inherently subjective and not based on any formulas or weighing of factors."[50] Accordingly, PacifiCorp does not use other companies as benchmarks. In fact, under PacifiCorp's Annual Executive Plan, all Named Executive Officers (NEOs) are eligible to earn an annual discretionary cash incentive award, determined on a subjective basis at the

[49] See PAC/3100 McCoy/17.
[50] PacifiCorp. (2019). *Form 10-K 2019*. Retrieved from SEC EDGAR website http://www.sec.gov/edgar.shtml

1 Chairman and CEO's "sole discretion, not based on a specific formula or
2 cap."[51] A variety of factors in are considered in determining each NEO's annual
3 incentive award including "the NEO's performance, PacifiCorp's overall
4 performance and each NEO's contribution to that overall performance."[52]
5 What's more, AIP is not the only award included in Company's Test Year. [53]
6 NEOs may also receive additional periodic cash performance awards for the
7 accomplishment of significant projects, once again at the sole discretion of the
8 Chairman and CEO.[54] Interestingly, the Company does not want to make its
9 incentive compensation criteria public but it does want the public to pay for it.
10 Moreover, Staff has reason to believe that executive compensation was
11 undercounted in the Test Year. Company's response for why Officer Incentives
12 went from $2.2 million in 2019 to $150 thousand in the Test Year was that "the
13 base year is based the *actual Annual Incentive Plan* whereas the test year is a
14 calculation based on average payout percentage for all eligible employees for
15 2016-2018."[55] It is worth noting that the average executive incentive payment
16 for calendar years 2014 through 2019 was $1.1 million.[56]
17 Employee incentives are even more shrouded in secrecy. For all of Staff's
18 requests for a detailed explanation of ROE targets, financial targets,

[51] PacifiCorp. (2019). *Form 10-K 2019*. Retrieved from SEC EDGAR website http://www.sec.gov/edgar.shtml
[52] Ibid
[53] Staff/2501, PAC Response to DR 125.
[54] PacifiCorp. (2019). *Form 10-K 2019*. Retrieved from SEC EDGAR website http://www.sec.gov/edgar.shtml
[55] Staff/2501, PAC Response to DR 275.
[56] Staff/2501, PAC Response to DR 178.

1 performance targets and anything which quantifies how awards are meted out,
2 PacifiCorp produces this meaningless graphic[57]:



3

4 But no matter, much like the executive incentives, awards are decided by
5 presidents-only in collaboration with senior management.[58] Once again,
6 PacifiCorp wants an open checkbook but bristles at the requirement of full
7 transparency.

8 Utilities under the Oregon jurisdiction have been treated the same under
9 these principles for over 15 years, eliminating any competitive disadvantage to
10 one particular utility. In fact, many utilities filing a general rate case have
11 already conceded executive bonuses and half of non-executive bonuses in
12 their own adjustments in an effort to follow commission policy.[59] Finally, the
13 Utility industry is one of the highest paying, mostly due to "supplements" or
14 pensions, insurance plans, profit-sharing and retirement plans.[60] In the wake of
15 a global pandemic and despite hundreds of companies reducing the salaries of
16 their CEOs (a third of S&P companies suspending executive pay entirely), the

[57] Staff/2501, PAC Response to DRs 125, 171, 179, 180.
[58] See Staff/2501, PAC Response to DR 125.
[59] See UG 390 CNGC/300/Peters/8, See UG 389 Avista/500/Brandon/21.
[60] EMSI: labor market analytics. https://www.economicmodeling.com/2020/05/14/highest-paying-industries/

1 Company is asking ratepayers to subsidize more of its incentives.[61] Once
2 again, Staff wants to draw your attention to the scale of its adjustments
3 (illustrated below) compared to the juggernaut that is PacifiCorp.[62]
4

	Base Wages and Salaries	Overtime	Incentives/Plant Incentives	Total
Company's Test Year	464,063,773	84,282,760	33,542,930	581,889,463
OR Allocation	0.283	0.283	0.283	0.283
Oregon Amount	131,330,048	23,852,021	9,492,649	164,674,718
Staff Adjustment	1,574,372	1,538,713	5,314,620	8,427,705
Adjustment as % of Test Year	**1.20%**	**6.45%**	**55.99%**	**5.12%**

5
6
7

[61] Cutter, C and Francis, T. CEO Salaries Decline, Stock Awards Remain. Wall Street Journal, June 4, 2020.
[62] Staff/2501, PAC Response to DRs 92 &123, See Staff electronic Workpaper UE 374 Exhibit 2500 Issue 1 Wage and Salary Model CONF

1 **ISSUE 3, ADVERTISING**

2 **Q. Does the Company have an additional adjustment for its Category A**
3 **advertising expenses?**

4 A. Yes, the Company has recalculated its expenses and updated the adjusted
5 amount to $958,130 from $745,618 based on updated allocation factors.[63] This
6 is based on the .125 percent limit of Category A advertising per Oregon
7 Administrative Rule 860-026-0022.

8 **Q. Does Staff accept the Company's adjustment?**

9 A. Yes. Staff accepts this updated adjustment.

10 **Q. Does this conclude your testimony?**

11 A. Yes.

12

13

[63] See PAC/3100 McCoy at 8.

CASE: UE 374
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2501

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Standard Data Request – OPUC 092

Wage and Salary Data: For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data.

Year: 2XXX		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company ❶ FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
❶ Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Response to Standard Data Request – OPUC 092

Please refer to Attachment OPUC 092 for requested information for the test year and the four calendar years 2016 through 2019, on a total company basis.

Standard Data Request – OPUC 099

Wage and Salary Data: Please demonstrate whether the wages and salaries in the Test Year or the preceding four calendar years are above or below market compensation. Please provide the information relied upon to demonstrate the Company's assertion of whether wages and salaries are above or below market levels.

Response to Standard Data Request – OPUC 099

Please refer to Attachment OPUC 099-1 through OPUC 099-3 for merit survey analysis from World at Work, for 2017 to 2020. This analysis provides PacifiCorp with the necessary data for comparison and placement within the competitive marketplace. The data was obtained from World at Work's Salary Budget Surveys. This survey is the largest survey available of its kind.

The PacifiCorp merit pool for 2017-2020 is as follows:

Year	Effective Date	Pool %
2020 Merit	12/26/2019	2.80%
2019 Merit	12/26/2018	2.70%
2018 Merit	12/26/2017	2.54%
2017 Merit	12/26/2016	2.34%

WorldatWork. Salary Budget Survey

Top-Level Results

Published June 30, 2017

This is a high-level look at results from the "WorldatWork 2017-2018 Salary Budget Survey," which closed in May 2017. This year, WorldatWork received a total of 4,942 responses. Additional industry and geographic breakout information for the "WorldatWork 2017-2018 Salary Budget Survey" that can be customized in countless ways for the U.S. and Canada is included in the "Online Reporting Tool," which will be available with the full survey results in early August. Participants will receive a complimentary subscription.

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United States

Salary Budget Increases, by Type of Increase

	Actual 2016		Projected 2017		Actual 2017		Projected 2018	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
General Increase/COLA	1.4%	1.5%	1.6%	2.0%	1.4%	1.5%	1.6%	2.0%
Merit Increase	2.7%	3.0%	2.9%	3.0%	2.8%	3.0%	2.9%	3.0%
Other Increase	0.9%	0.5%	0.8%	0.5%	0.9%	0.5%	0.9%	0.5%
Total Increase	**3.0%**	**3.0%**	**3.1%**	**3.0%**	**3.0%**	**3.0%**	**3.1%**	**3.0%**

Note: "General Increase/COLA," "Merit Increase" and "Other Increase" do not add to the "Total Increase" because not every organization provides all three types of increase. In addition, each type of increase may include multiple responses if each respondent reports for more than one employee category for that type of increase.

Total Salary Budget Increases, by Employee Category

	Actual 2016		Projected 2017		Actual 2017		Projected 2018	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonexempt Hourly Nonunion	3.0%	3.0%	3.1%	3.0%	3.0%	3.0%	3.1%	3.0%
Nonexempt Salaried	2.9%	3.0%	3.0%	3.0%	3.0%	3.0%	3.1%	3.0%
Exempt Salaried	3.0%	3.0%	3.1%	3.0%	3.0%	3.0%	3.2%	3.0%
Officers/Executives	3.0%	3.0%	3.1%	3.0%	3.0%	3.0%	3.2%	3.0%
All	**3.0%**	**3.0%**	**3.1%**	**3.0%**	**3.0%**	**3.0%**	**3.1%**	**3.0%**

Total Salary Budget Increases, by State

	Actual 2017		Projected 2018	
	Mean	Median	Mean	Median
National	**3.0%**	**3.0%**	**3.1%**	**3.0%**
Alabama	2.9%	3.0%	3.1%	3.0%
Alaska	2.9%	3.0%	3.2%	3.0%
Arizona	3.0%	3.0%	3.1%	3.0%
Arkansas	2.9%	3.0%	3.1%	3.0%
California	3.1%	3.0%	3.2%	3.0%
Colorado	3.0%	3.0%	3.2%	3.0%
Connecticut	3.0%	3.0%	3.1%	3.0%
Delaware	2.9%	3.0%	3.2%	3.0%
Florida	3.0%	3.0%	3.1%	3.0%
Georgia	3.0%	3.0%	3.2%	3.0%
Hawaii	2.9%	3.0%	3.2%	3.0%
Idaho	2.9%	3.0%	3.2%	3.0%
Illinois	3.0%	3.0%	3.2%	3.0%
Indiana	3.0%	3.0%	3.1%	3.0%
Iowa	3.0%	3.0%	3.2%	3.0%
Kansas	2.9%	3.0%	3.1%	3.0%
Kentucky	2.9%	3.0%	3.1%	3.0%
Louisiana	2.9%	3.0%	3.1%	3.0%
Maine	2.9%	3.0%	3.1%	3.0%
Maryland	3.0%	3.0%	3.1%	3.0%
Massachusetts	3.0%	3.0%	3.2%	3.0%
Michigan	3.0%	3.0%	3.1%	3.0%
Minnesota	3.0%	3.0%	3.1%	3.0%
Mississippi	3.0%	3.0%	3.1%	3.0%
Missouri	2.9%	3.0%	3.1%	3.0%
Montana	2.9%	3.0%	3.2%	3.0%
Nebraska	2.9%	3.0%	3.2%	3.0%
Nevada	2.9%	3.0%	3.1%	3.0%
New Hampshire	3.0%	3.0%	3.2%	3.0%
New Jersey	3.0%	3.0%	3.1%	3.0%
New Mexico	2.9%	3.0%	3.1%	3.0%
New York	3.0%	3.0%	3.1%	3.0%
North Carolina	3.0%	3.0%	3.2%	3.0%
North Dakota	2.9%	3.0%	3.2%	3.0%

	Actual 2017		Projected 2018	
	Mean	Median	Mean	Median
Ohio	2.9%	3.0%	3.1%	3.0%
Oklahoma	3.0%	3.0%	3.2%	3.0%
Oregon	3.0%	3.0%	3.2%	3.0%
Pennsylvania	3.0%	3.0%	3.1%	3.0%
Rhode Island	2.9%	3.0%	3.1%	3.0%
South Carolina	2.9%	3.0%	3.1%	3.0%
South Dakota	3.0%	3.0%	3.2%	3.0%
Tennessee	3.0%	3.0%	3.1%	3.0%
Texas	3.0%	3.0%	3.1%	3.0%
Utah	3.0%	3.0%	3.2%	3.0%
Vermont	2.9%	3.0%	3.2%	3.0%
Virginia	3.0%	3.0%	3.2%	3.0%
Washington	3.0%	3.0%	3.2%	3.0%
West Virginia	2.9%	3.0%	3.2%	3.0%
Wisconsin	2.9%	3.0%	3.1%	3.0%
Wyoming	2.9%	3.0%	3.2%	3.0%

All data includes 0% responses.

Total Salary Budget Increases, by Major Metropolitan Area

	Actual 2017		Projected 2018	
	Mean	Median	Mean	Median
National	**3.0%**	**3.0%**	**3.1%**	**3.0%**
Atlanta	3.3%	3.0%	3.3%	3.0%
Baltimore	3.1%	3.0%	3.1%	3.0%
Boston	3.1%	3.0%	3.1%	3.0%
Chicago	3.1%	3.0%	3.2%	3.0%
Cincinnati	3.0%	3.0%	3.1%	3.0%
Cleveland	3.0%	3.0%	3.1%	3.0%
Dallas	3.2%	3.0%	3.2%	3.0%
Denver	3.1%	3.0%	3.2%	3.0%
Detroit	3.1%	3.0%	3.2%	3.0%
Houston	3.1%	3.0%	3.1%	3.0%
Los Angeles	3.2%	3.0%	3.1%	3.0%
Miami	3.1%	3.0%	3.2%	3.0%
Minneapolis	3.0%	3.0%	3.0%	3.0%

	Actual 2017		Projected 2018	
	Mean	Median	Mean	Median
New York	3.1%	3.0%	3.1%	3.0%
Philadelphia	3.1%	3.0%	3.2%	3.0%
Phoenix	3.2%	3.0%	3.1%	3.0%
Pittsburgh	3.1%	3.0%	3.1%	3.0%
Portland	3.3%	3.0%	3.2%	3.0%
San Diego	3.1%	3.0%	3.1%	3.0%
San Francisco	3.2%	3.0%	3.3%	3.0%
San Jose	3.2%	3.0%	3.3%	3.0%
Seattle	3.2%	3.0%	3.2%	3.0%
St. Louis	3.1%	3.0%	3.1%	3.0%
Tampa	3.1%	3.0%	3.1%	3.0%
Washington, D.C.	3.0%	3.0%	3.1%	3.0%

Merit Increases Awarded, by Performance Category

	High Performers		Middle Performers		Low Performers	
2016	Mean	Median	Mean	Median	Mean	Median
Percentage of employees rated in this category for 2016	27%	25%	67%	70%	5%	4%
Average merit increase awarded to this 2016 performance category	4.0%	4.0%	2.7%	2.8%	0.7%	0.2%
2017						
Percentage of employees estimated to be rated in this category for 2017	26%	22%	68%	70%	6%	5%
Average merit increase estimated for this 2017 performance category	4.0%	4.0%	2.8%	3.0%	0.6%	0.0%

Note: The mean distribution of the percent of employees in each performance category will total 100% or, as a result of rounding, may be very close. However, by definition, the median value for each category will move depending on the frequency of values in the dataset. Therefore, the median distribution of the percent of employees in each category will not equal 100%.

All data includes 0% responses.

Salary Structure Increases, by Employee Category

	Actual 2016		Projected 2017		Actual 2017		Projected 2018	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonexempt Hourly Nonunion	1.9%	2.0%	2.1%	2.0%	2.0%	2.0%	2.1%	2.0%
Nonexempt Salaried	1.9%	2.0%	2.1%	2.0%	2.0%	2.0%	2.1%	2.0%
Exempt Salaried	2.0%	2.0%	2.1%	2.0%	2.0%	2.0%	2.1%	2.0%
Officers/Executives	2.0%	2.0%	2.1%	2.0%	2.1%	2.0%	2.1%	2.0%
All	**1.9%**	**2.0%**	**2.1%**	**2.0%**	**2.0%**	**2.0%**	**2.1%**	**2.0%**

Variable Pay Programs, 2016-2018

National	Nonexempt Hourly Nonunion		Nonexempt Salaried		Exempt Salaried		Officers/Executives	
2016	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Average percent budgeted	5.6%	5.0%	6.3%	5.0%	13.3%	12.8%	39.0%	35.0%
Average percent paid	5.3%	5.0%	6.2%	5.0%	12.8%	11.0%	39.0%	34.0%
Percent of employees eligible in 2016 for variable pay	88%	100%	94%	100%	81%	100%	94%	100%
Percent of eligible employees actually paid variable pay for 2016	83%	98%	88%	99%	81%	98%	90%	100%
2017								
Average percent budgeted	5.5%	5.0%	6.4%	5.0%	13.4%	13.0%	39.1%	35.0%
Projected percent paid	5.5%	5.0%	6.4%	5.0%	13.1%	12.0%	39.6%	35.0%
2018								
Projected percent budgeted	5.5%	5.0%	6.3%	5.0%	13.4%	12.9%	39.0%	35.0%

All data includes 0% responses.

Canada

Salary Budget Increases, by Type of Increase

	Actual 2016		Projected 2017		Actual 2017		Projected 2018	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
General Increase/COLA	1.1%	1.0%	1.3%	1.4%	1.4%	1.5%	1.6%	1.9%
Merit Increase	2.5%	2.8%	2.6%	3.0%	2.5%	2.8%	2.7%	3.0%
Other Increase	0.8%	0.5%	0.7%	0.5%	0.9%	0.5%	1.1%	0.5%
Total Increase	**2.6%**	**3.0%**	**2.8%**	**3.0%**	**2.8%**	**3.0%**	**3.0%**	**3.0%**

Note: "General Increase/COLA," "Merit Increase" and "Other Increase" do not add to the "Total Increase" because not every organization provides all three types of increase. In addition, each type of increase may include multiple responses if each respondent reports for more than one employee category for that type of increase.

Total Salary Budget Increases, by Employee Category

	Actual 2016		Projected 2017		Actual 2017		Projected 2018	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonmanagement Hourly Nonunion	2.6%	3.0%	2.8%	3.0%	2.7%	3.0%	3.0%	3.0%
Nonmanagement Salaried	2.7%	3.0%	2.8%	3.0%	2.8%	3.0%	3.1%	3.0%
Management Salaried	2.7%	3.0%	2.9%	3.0%	2.8%	3.0%	3.0%	3.0%
Officers/Executives	2.6%	3.0%	2.8%	3.0%	2.8%	3.0%	3.0%	3.0%
All	**2.6%**	**3.0%**	**2.8%**	**3.0%**	**2.8%**	**3.0%**	**3.0%**	**3.0%**

Salary Budget Increases, by Province

	Actual 2017		Projected 2018	
	Mean	Median	Mean	Median
National	**2.8%**	**3.0%**	**3.0%**	**3.0%**
Alberta	2.7%	2.8%	2.9%	3.0%
British Columbia	2.7%	2.8%	3.0%	3.0%
Manitoba	2.7%	2.6%	2.9%	3.0%
New Brunswick	2.6%	2.5%	2.6%	2.5%
Newfoundland	2.4%	2.5%	2.6%	2.6%
Northwest Territories	2.5%	2.5%	2.5%	2.5%
Nova Scotia	2.5%	2.6%	2.7%	3.0%
Nunavut	2.3%	2.1%	2.4%	2.5%
Ontario	2.9%	3.0%	3.0%	3.0%
Prince Edward Island	2.5%	2.5%	2.5%	2.5%
Quebec	2.8%	3.0%	2.9%	3.0%
Saskatchewan	2.5%	2.5%	2.8%	3.0%
Yukon	2.6%	2.5%	2.5%	2.5%

All data includes 0% responses.

Total Salary Budget Increases, by Major Metropolitan Area

	Actual 2017		Projected 2018	
	Mean	Median	Mean	Median
National	**2.8%**	**3.0%**	**3.0%**	**3.0%**
Calgary	2.5%	2.6%	2.8%	3.0%
Edmonton	2.4%	2.6%	2.7%	3.0%
Hamilton	2.7%	3.0%	2.8%	3.0%
Montreal	2.8%	3.0%	2.9%	3.0%
Ottawa	2.7%	3.0%	2.9%	3.0%
Quebec	2.7%	3.0%	2.8%	3.0%
Toronto	2.8%	3.0%	3.1%	3.0%
Vancouver	2.6%	2.6%	2.8%	3.0%
Winnipeg	2.6%	2.6%	2.8%	3.0%

Salary Structure Increases, by Employee Category

	Actual 2016		Projected 2017		Actual 2017		Projected 2018	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonmanagement Hourly Nonunion	1.6%	2.0%	1.9%	2.0%	1.7%	2.0%	1.9%	2.0%
Nonmanagement Salaried	1.6%	2.0%	1.8%	2.0%	1.7%	2.0%	1.9%	2.0%
Management Salaried	1.6%	2.0%	1.9%	2.0%	1.8%	2.0%	1.9%	2.0%
Officers/Executives	1.4%	1.9%	1.7%	2.0%	1.7%	2.0%	1.8%	2.0%
All	**1.6%**	**2.0%**	**1.8%**	**2.0%**	**1.7%**	**2.0%**	**1.9%**	**2.0%**

All data includes 0% responses.

Global

Salary Budget Increases, by Type of Increase

		Actual 2017		Projected 2018	
	Type of Increase	Mean	Median	Mean	Median
Australia	General Increase/COLA	1.6%	1.9%	1.4%	1.5%
	Merit Increase	3.0%	3.0%	3.1%	3.0%
	Other Increase	0.7%	0.5%	0.7%	0.5%
	Total Increase	**3.2%**	**3.2%**	**3.3%**	**3.2%**
Belgium	General Increase/COLA	1.6%	1.1%	1.4%	1.1%
	Merit Increase	2.0%	2.0%	2.1%	2.1%
	Other Increase	0.7%	0.5%	0.6%	0.5%
	Total Increase	**2.5%**	**2.5%**	**2.5%**	**2.5%**
Brazil	General Increase/COLA	7.4%	8.0%	7.4%	8.0%
	Merit Increase	5.3%	6.3%	5.8%	7.0%
	Other Increase	3.7%	1.7%	3.3%	1.0%
	Total Increase	**7.5%**	**8.2%**	**7.7%**	**8.3%**
China	General Increase/COLA	4.0%	2.8%	3.7%	3.0%
	Merit Increase	6.6%	7.0%	6.7%	7.0%
	Other Increase	1.0%	0.5%	1.1%	0.8%
	Total Increase	**6.9%**	**7.0%**	**7.0%**	**7.3%**
France	General Increase/COLA	1.2%	1.0%	1.2%	1.0%
	Merit Increase	2.4%	2.5%	2.5%	2.5%
	Other Increase	0.7%	0.5%	0.6%	0.5%
	Total Increase	**2.5%**	**2.5%**	**2.6%**	**2.6%**
Germany	General Increase/COLA	1.6%	2.0%	1.7%	1.5%
	Merit Increase	2.8%	3.0%	2.9%	3.0%
	Other Increase	0.7%	0.5%	0.7%	0.5%
	Total Increase	**3.0%**	**3.0%**	**3.1%**	**3.0%**
India	General Increase/COLA	6.8%	8.5%	7.1%	9.0%
	Merit Increase	9.6%	10.0%	9.9%	10.1%
	Other Increase	1.5%	1.0%	1.3%	1.0%
	Total Increase	**10.1%**	**10.5%**	**10.2%**	**10.5%**
Italy	General Increase/COLA	1.3%	0.9%	1.1%	0.6%
	Merit Increase	2.4%	2.5%	2.7%	2.5%
	Other Increase	0.9%	0.5%	0.7%	0.5%
	Total Increase	**2.8%**	**2.6%**	**2.9%**	**2.8%**
Japan	General Increase/COLA	1.0%	0.7%	0.4%	0.0%
	Merit Increase	2.3%	2.4%	2.5%	2.5%
	Other Increase	0.6%	0.5%	0.6%	0.5%
	Total Increase	**2.5%**	**2.5%**	**2.7%**	**2.5%**
Mexico	General Increase/COLA	3.4%	4.0%	3.1%	3.4%
	Merit Increase	4.3%	4.5%	4.4%	4.5%
	Other Increase	0.9%	0.5%	0.7%	0.5%
	Total Increase	**4.5%**	**4.5%**	**4.5%**	**4.5%**

(Continued on page 8)

All data includes 0% responses.

Salary Budget Increases, by Type of Increase *(continued)*

		Actual 2017		Projected 2018	
	Type of Increase	Mean	Median	Mean	Median
Netherlands	General Increase/COLA	1.6%	1.3%	1.7%	2.0%
	Merit Increase	2.5%	2.6%	2.5%	2.7%
	Other Increase	0.7%	0.5%	0.6%	0.5%
	Total Increase	**2.8%**	**2.8%**	**2.9%**	**3.0%**
Russia	General Increase/COLA	5.2%	7.0%	6.3%	8.0%
	Merit Increase	7.4%	8.0%	7.9%	8.0%
	Other Increase	1.2%	0.7%	0.9%	0.7%
	Total Increase	**7.7%**	**8.0%**	**8.2%**	**8.0%**
Singapore	General Increase/COLA	1.9%	1.3%	1.9%	1.5%
	Merit Increase	3.9%	4.0%	3.9%	4.0%
	Other Increase	0.9%	0.5%	0.8%	0.5%
	Total Increase	**4.1%**	**4.0%**	**4.2%**	**4.0%**
Spain	General Increase/COLA	1.1%	1.3%	1.1%	1.3%
	Merit Increase	2.4%	2.2%	2.3%	2.3%
	Other Increase	0.7%	0.5%	0.6%	0.5%
	Total Increase	**2.6%**	**2.4%**	**2.6%**	**2.5%**
Sweden	General Increase/COLA	2.7%	2.5%	*	*
	Merit Increase	2.6%	2.7%	2.8%	2.7%
	Other Increase	0.7%	0.5%	0.6%	0.5%
	Total Increase	**2.9%**	**2.9%**	**3.0%**	**3.0%**
Switzerland	General Increase/COLA	1.0%	0.2%	1.3%	1.2%
	Merit Increase	2.0%	2.0%	2.1%	2.0%
	Other Increase	0.8%	0.4%	0.5%	0.4%
	Total Increase	**2.3%**	**2.0%**	**2.3%**	**2.1%**
United Kingdom	General Increase/COLA	1.5%	1.5%	1.5%	2.0%
	Merit Increase	2.7%	3.0%	2.8%	3.0%
	Other Increase	0.8%	0.5%	0.7%	0.5%
	Total Increase	**2.9%**	**3.0%**	**3.1%**	**3.0%**

Note: "General Increase/COLA," "Merit Increase" and "Other Increase" do not add to the "Total Increase" because not every organization provides all three types of increase. In addition, each type of increase may include multiple responses if each respondent reports for more than one employee category for that type of increase.

*Less than 5 responses.

Total Salary Budget Increases, by Employee Category

		Actual 2017		Projected 2018	
	Employee Category	Mean	Median	Mean	Median
Australia	NHN	3.2%	3.2%	3.2%	3.3%
	NS	3.3%	3.2%	3.3%	3.2%
	MS	3.3%	3.2%	3.3%	3.2%
	OE	3.2%	3.1%	3.3%	3.3%
	All	**3.2%**	**3.2%**	**3.3%**	**3.2%**
Belgium	NHN	2.5%	2.5%	2.5%	2.4%
	NS	2.4%	2.5%	2.5%	2.5%
	MS	2.4%	2.5%	2.5%	2.5%
	OE	2.5%	2.7%	2.6%	2.7%
	All	**2.5%**	**2.5%**	**2.5%**	**2.5%**
Brazil	NHN	7.0%	8.0%	6.9%	8.0%
	NS	7.5%	8.0%	7.6%	8.0%
	MS	7.6%	8.2%	7.8%	8.3%
	OE	7.8%	8.5%	8.3%	8.5%
	All	**7.5%**	**8.2%**	**7.7%**	**8.3%**
China	NHN	7.0%	7.2%	7.1%	7.5%
	NS	6.8%	7.0%	7.0%	7.3%
	MS	6.8%	7.0%	7.0%	7.3%
	OE	6.8%	7.0%	7.0%	7.3%
	All	**6.9%**	**7.0%**	**7.0%**	**7.3%**
France	NHN	2.5%	2.5%	2.6%	2.8%
	NS	2.5%	2.5%	2.6%	2.5%
	MS	2.6%	2.6%	2.7%	2.7%
	OE	2.5%	2.7%	2.5%	2.8%
	All	**2.5%**	**2.5%**	**2.6%**	**2.6%**
Germany	NHN	2.9%	3.0%	3.0%	3.0%
	NS	3.0%	3.0%	3.1%	3.0%
	MS	3.0%	3.0%	3.1%	3.0%
	OE	2.9%	3.0%	3.0%	3.0%
	All	**3.0%**	**3.0%**	**3.1%**	**3.0%**
India	NHN	9.9%	10.1%	9.9%	10.3%
	NS	10.2%	10.5%	10.3%	10.5%
	MS	10.1%	10.5%	10.3%	10.5%
	OE	9.8%	10.5%	10.1%	10.5%
	All	**10.1%**	**10.5%**	**10.2%**	**10.5%**
Italy	NHN	3.0%	2.8%	3.1%	2.8%
	NS	2.7%	2.5%	2.9%	2.6%
	MS	2.7%	2.6%	2.8%	2.7%
	OE	2.9%	2.8%	3.1%	2.8%
	All	**2.8%**	**2.6%**	**2.9%**	**2.8%**
Japan	NHN	2.5%	2.5%	2.7%	2.5%
	NS	2.6%	2.5%	2.6%	2.5%
	MS	2.5%	2.5%	2.6%	2.5%
	OE	2.6%	2.8%	2.8%	2.8%
	All	**2.5%**	**2.5%**	**2.7%**	**2.5%**

NHN Nonmanagement Hourly Nonunion | **NS** Nonmanagement Salaried | **MS** Management Salaried | **OE** Officers/Executives *(Continued on page 10)*

All data includes 0% responses.

Total Salary Budget Increases, by Employee Category *(continued)*

	Employee Category	Actual 2017 Mean	Actual 2017 Median	Projected 2018 Mean	Projected 2018 Median
Mexico	NHN	4.6%	4.5%	4.7%	4.8%
	NS	4.5%	4.5%	4.5%	4.5%
	MS	4.5%	4.5%	4.5%	4.5%
	OE	4.3%	4.5%	4.4%	4.5%
	All	**4.5%**	**4.5%**	**4.5%**	**4.5%**
Netherlands	NHN	2.9%	2.9%	3.0%	3.0%
	NS	2.7%	2.8%	2.8%	3.0%
	MS	2.8%	2.8%	2.8%	2.9%
	OE	2.7%	2.8%	3.0%	3.0%
	All	**2.8%**	**2.8%**	**2.9%**	**3.0%**
Russia	NHN	7.1%	8.0%	7.9%	8.0%
	NS	7.6%	8.0%	8.1%	8.0%
	MS	7.8%	8.0%	8.3%	8.0%
	OE	7.9%	8.0%	8.4%	8.1%
	All	**7.7%**	**8.0%**	**8.2%**	**8.0%**
Singapore	NHN	4.1%	4.0%	4.1%	4.0%
	NS	4.1%	4.0%	4.2%	4.0%
	MS	4.2%	4.0%	4.2%	4.0%
	OE	4.1%	4.0%	4.1%	4.2%
	All	**4.1%**	**4.0%**	**4.2%**	**4.0%**
Spain	NHN	2.4%	2.3%	2.6%	2.5%
	NS	2.7%	2.3%	2.6%	2.5%
	MS	2.5%	2.4%	2.6%	2.5%
	OE	3.0%	2.6%	2.7%	2.8%
	All	**2.6%**	**2.4%**	**2.6%**	**2.5%**
Sweden	NHN	3.0%	3.0%	3.1%	3.0%
	NS	2.8%	2.9%	3.0%	3.0%
	MS	2.9%	2.9%	3.0%	3.0%
	OE	2.7%	2.9%	2.9%	2.9%
	All	**2.9%**	**2.9%**	**3.0%**	**3.0%**
Switzerland	NHN	2.9%	2.1%	2.3%	2.1%
	NS	2.1%	2.0%	2.3%	2.1%
	MS	2.2%	2.0%	2.3%	2.1%
	OE	2.1%	2.0%	2.3%	2.2%
	All	**2.3%**	**2.0%**	**2.3%**	**2.1%**
United Kingdom	NHN	2.9%	3.0%	3.0%	3.0%
	NS	2.9%	3.0%	3.1%	3.0%
	MS	3.0%	3.0%	3.1%	3.0%
	OE	2.9%	3.0%	3.0%	3.0%
	All	**2.9%**	**3.0%**	**3.1%**	**3.0%**

NHN Nonmanagement Hourly Nonunion | **NS** Nonmanagement Salaried | **MS** Management Salaried | **OE** Officers/Executives

All data includes 0% responses.

Please direct any questions or comments to surveypanel@worldatwork.org.

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WorldatWork Salary Budget Survey

Top-Level Results

Published June 25, 2018

This is a high-level look at results from the "WorldatWork 2018-2019 Salary Budget Survey," which closed in May 2018. This year, WorldatWork received a total of 5,499 responses. Additional industry and geographic breakout information for the "WorldatWork 2018-2019 Salary Budget Survey" that can be customized in countless ways for the U.S. and Canada is included in the "Online Reporting Tool," which will be available with the full survey results in early August. Participants will receive a complimentary subscription.

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United States

Salary Budget Increases, by Type of Increase

	Actual 2017		Projected 2018		Actual 2018		Projected 2019	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
General Increase/COLA	1.4%	1.5%	1.6%	2.0%	1.5%	2.0%	1.8%	2.0%
Merit Increase	2.8%	3.0%	2.9%	3.0%	2.8%	3.0%	2.9%	3.0%
Other Increase	0.9%	0.5%	0.9%	0.5%	0.8%	0.5%	0.9%	0.5%
Total Increase	**3.0%**	**3.0%**	**3.1%**	**3.0%**	**3.1%**	**3.0%**	**3.2%**	**3.0%**

Note: "General Increase/COLA," "Merit Increase" and "Other Increase" do not add to the "Total Increase" because not every organization provides all three types of increase. In addition, each type of increase may include multiple responses if each respondent reports for more than one employee category for that type of increase.

Total Salary Budget Increases, by Employee Category

	Actual 2017		Projected 2018		Actual 2018		Projected 2019	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonexempt Hourly Nonunion	3.0%	3.0%	3.1%	3.0%	3.1%	3.0%	3.1%	3.0%
Nonexempt Salaried	3.0%	3.0%	3.1%	3.0%	3.1%	3.0%	3.1%	3.0%
Exempt Salaried	3.0%	3.0%	3.2%	3.0%	3.1%	3.0%	3.2%	3.0%
Officers/Executives	3.0%	3.0%	3.2%	3.0%	3.1%	3.0%	3.2%	3.0%
All	**3.0%**	**3.0%**	**3.1%**	**3.0%**	**3.1%**	**3.0%**	**3.2%**	**3.0%**

Total Salary Budget Increases, by State

	Actual 2018		Projected 2019	
	Mean	Median	Mean	Median
National	**3.1%**	**3.0%**	**3.2%**	**3.0%**
Alabama	3.0%	3.0%	3.0%	3.0%
Alaska	3.0%	3.0%	3.0%	3.0%
Arizona	3.0%	3.0%	3.1%	3.0%
Arkansas	2.9%	3.0%	3.0%	3.0%
California	3.1%	3.0%	3.1%	3.0%
Colorado	3.0%	3.0%	3.1%	3.0%
Connecticut	3.0%	3.0%	3.0%	3.0%
Delaware	3.0%	3.0%	3.0%	3.0%
Florida	3.0%	3.0%	3.1%	3.0%
Georgia	3.0%	3.0%	3.1%	3.0%
Hawaii	2.9%	3.0%	3.0%	3.0%
Idaho	3.0%	3.0%	3.1%	3.0%
Illinois	3.0%	3.0%	3.1%	3.0%
Indiana	3.0%	3.0%	3.0%	3.0%
Iowa	2.9%	3.0%	3.0%	3.0%
Kansas	3.0%	3.0%	3.0%	3.0%
Kentucky	3.0%	3.0%	3.0%	3.0%
Louisiana	3.0%	3.0%	3.0%	3.0%
Maine	3.0%	3.0%	3.0%	3.0%
Maryland	3.0%	3.0%	3.0%	3.0%
Massachusetts	3.0%	3.0%	3.1%	3.0%
Michigan	3.0%	3.0%	3.0%	3.0%
Minnesota	3.0%	3.0%	3.0%	3.0%
Mississippi	3.0%	3.0%	3.0%	3.0%
Missouri	3.0%	3.0%	3.0%	3.0%
Montana	3.0%	3.0%	3.1%	3.0%
Nebraska	3.0%	3.0%	3.0%	3.0%
Nevada	3.0%	3.0%	3.1%	3.0%
New Hampshire	2.9%	3.0%	3.0%	3.0%
New Jersey	3.0%	3.0%	3.0%	3.0%
New Mexico	3.0%	3.0%	3.0%	3.0%
New York	3.0%	3.0%	3.1%	3.0%
North Carolina	3.0%	3.0%	3.1%	3.0%
North Dakota	2.9%	3.0%	3.1%	3.0%

	Actual 2018		Projected 2019	
	Mean	Median	Mean	Median
Ohio	3.0%	3.0%	3.1%	3.0%
Oklahoma	3.0%	3.0%	3.1%	3.0%
Oregon	3.0%	3.0%	3.1%	3.0%
Pennsylvania	3.0%	3.0%	3.1%	3.0%
Rhode Island	3.0%	3.0%	3.0%	3.0%
South Carolina	3.0%	3.0%	3.1%	3.0%
South Dakota	3.0%	3.0%	3.0%	3.0%
Tennessee	3.0%	3.0%	3.0%	3.0%
Texas	3.1%	3.0%	3.1%	3.0%
Utah	3.0%	3.0%	3.1%	3.0%
Vermont	2.9%	3.0%	3.0%	3.0%
Virginia	3.0%	3.0%	3.1%	3.0%
Washington	3.1%	3.0%	3.1%	3.0%
West Virginia	2.9%	3.0%	3.0%	3.0%
Wisconsin	3.0%	3.0%	3.0%	3.0%
Wyoming	3.0%	3.0%	3.0%	3.0%

All data includes 0% responses.

Total Salary Budget Increases, by Major Metropolitan Area

	Actual 2018		Projected 2019	
	Mean	Median	Mean	Median
National	**3.1%**	**3.0%**	**3.2%**	**3.0%**
Atlanta	3.1%	3.0%	3.1%	3.0%
Baltimore	3.0%	3.0%	3.1%	3.0%
Boston	3.0%	3.0%	3.1%	3.0%
Chicago	3.1%	3.0%	3.1%	3.0%
Cincinnati	3.1%	3.0%	3.1%	3.0%
Cleveland	3.1%	3.0%	3.1%	3.0%
Dallas	3.2%	3.0%	3.2%	3.0%
Denver	3.1%	3.0%	3.1%	3.0%
Detroit	2.9%	3.0%	2.9%	3.0%
Houston	3.1%	3.0%	3.1%	3.0%
Los Angeles	3.2%	3.0%	3.2%	3.0%
Miami	3.1%	3.0%	3.1%	3.0%
Minneapolis	3.1%	3.0%	3.0%	3.0%

	Actual 2018		Projected 2019	
	Mean	Median	Mean	Median
New York	3.1%	3.0%	3.2%	3.0%
Philadelphia	3.1%	3.0%	3.0%	3.0%
Phoenix	3.1%	3.0%	3.1%	3.0%
Pittsburgh	3.0%	3.0%	3.1%	3.0%
Portland	3.2%	3.0%	3.3%	3.0%
San Diego	3.2%	3.0%	3.1%	3.0%
San Francisco	3.3%	3.0%	3.3%	3.0%
San Jose	3.3%	3.0%	3.3%	3.0%
Seattle	3.3%	3.0%	3.2%	3.0%
St. Louis	3.1%	3.0%	3.1%	3.0%
Tampa	3.0%	3.0%	3.1%	3.0%
Washington, D.C.	3.0%	3.0%	3.1%	3.0%

Merit Increases Awarded, by Performance Category

	High Performers		Middle Performers		Low Performers	
2017	Mean	Median	Mean	Median	Mean	Median
Percentage of employees rated in this category for 2017	27%	24%	68%	70%	6%	4%
Average merit increase awarded to this 2017 performance category	4.0%	3.9%	2.7%	2.8%	0.7%	0.5%
2018						
Percentage of employees estimated to be rated in this category for 2018	25%	21%	69%	70%	6%	5%
Average merit increase estimated for this 2018 performance category	4.1%	4.0%	2.8%	3.0%	0.6%	0.0%

Note: The mean distribution of the percent of employees in each performance category will total 100% or, as a result of rounding, may be very close. However, by definition, the median value for each category will move depending on the frequency of values in the dataset. Therefore, the median distribution of the percent of employees in each category will not equal 100%.

All data includes 0% responses.

Promotional Increases

	2016		2017		2018	
	Mean	Median	Mean	Median	Mean	Median
Percentage of employees that received promotional increases	7.9%	7.0%	8.6%	8.0%	--	--
Percentage of promoted employees' base salary	8.4%	8.0%	8.7%	8.5%	--	--
Planned spending on promotional increases as a percentage of total base salaries	1.5%	1.0%	1.6%	1.0%	1.5%	1.0%

-- Question was not an option in the survey questionnaire.

Salary Structure Increases, by Employee Category

	Actual 2017		Projected 2018		Actual 2018		Projected 2019	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonexempt Hourly Nonunion	2.0%	2.0%	2.1%	2.0%	2.0%	2.0%	2.1%	2.0%
Nonexempt Salaried	2.0%	2.0%	2.1%	2.0%	2.1%	2.0%	2.1%	2.0%
Exempt Salaried	2.0%	2.0%	2.1%	2.0%	2.1%	2.0%	2.2%	2.0%
Officers/Executives	2.1%	2.0%	2.1%	2.0%	2.0%	2.0%	2.2%	2.0%
All	**2.0%**	**2.0%**	**2.1%**	**2.0%**	**2.0%**	**2.0%**	**2.1%**	**2.0%**

Variable Pay Programs, 2017-2019

National	Nonexempt Hourly Nonunion		Nonexempt Salaried		Exempt Salaried		Officers/Executives	
2017	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Average percent budgeted	5.1%	5.0%	6.0%	5.0%	12.5%	12.0%	38.1%	35.0%
Average percent paid	5.3%	4.8%	6.1%	5.0%	12.6%	12.0%	39.6%	35.0%
Percent of employees eligible in 2017 for variable pay	87%	100%	92%	100%	82%	100%	93%	100%
Percent of eligible employees actually paid variable pay for 2017	82%	98%	88%	99%	82%	98%	91%	100%
2018								
Average percent budgeted	5.2%	5.0%	6.1%	5.0%	12.7%	12.0%	38.5%	35.0%
Projected percent paid	5.4%	5.0%	6.3%	5.0%	13.0%	12.0%	39.8%	35.0%
2019								
Projected percent budgeted	5.2%	5.0%	6.1%	5.0%	12.6%	12.0%	38.2%	35.0%

All data includes 0% responses.

Canada

Salary Budget Increases, by Type of Increase

	Actual 2017		Projected 2018		Actual 2018		Projected 2019	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
General Increase/COLA	1.4%	1.5%	1.6%	1.9%	1.4%	1.5%	1.6%	2.0%
Merit Increase	2.5%	2.8%	2.7%	3.0%	2.6%	2.8%	2.8%	3.0%
Other Increase	0.9%	0.5%	1.1%	0.5%	0.9%	0.5%	0.9%	0.5%
Total Increase	**2.8%**	**3.0%**	**3.0%**	**3.0%**	**2.9%**	**3.0%**	**3.0%**	**3.0%**

Note: "General Increase/COLA," "Merit Increase" and "Other Increase" do not add to the "Total Increase" because not every organization provides all three types of increase. In addition, each type of increase may include multiple responses if each respondent reports for more than one employee category for that type of increase.

Total Salary Budget Increases, by Employee Category

	Actual 2017		Projected 2018		Actual 2018		Projected 2019	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonmanagement Hourly Nonunion	2.7%	3.0%	3.0%	3.0%	2.8%	3.0%	2.9%	3.0%
Nonmanagement Salaried	2.8%	3.0%	3.1%	3.0%	2.9%	3.0%	3.0%	3.0%
Management Salaried	2.8%	3.0%	3.0%	3.0%	2.9%	3.0%	3.0%	3.0%
Officers/Executives	2.8%	3.0%	3.0%	3.0%	2.9%	3.0%	3.0%	3.0%
All	**2.8%**	**3.0%**	**3.0%**	**3.0%**	**2.9%**	**3.0%**	**3.0%**	**3.0%**

Salary Budget Increases, by Province

	Actual 2018		Projected 2019	
	Mean	Median	Mean	Median
National	**2.9%**	**3.0%**	**3.0%**	**3.0%**
Alberta	2.8%	2.8%	2.9%	3.0%
British Columbia	2.9%	3.0%	3.0%	3.0%
Manitoba	2.7%	2.7%	2.8%	2.8%
New Brunswick	2.5%	2.7%	2.7%	2.8%
Newfoundland	2.3%	2.5%	2.6%	2.5%
Northwest Territories	2.3%	2.5%	2.6%	2.5%
Nova Scotia	2.5%	2.5%	2.7%	2.7%
Nunavut	2.7%	2.8%	2.8%	3.0%
Ontario	2.9%	3.0%	3.0%	3.0%
Prince Edward Island	2.6%	2.7%	2.7%	2.8%
Quebec	2.8%	2.9%	2.9%	3.0%
Saskatchewan	2.6%	2.7%	2.9%	3.0%
Yukon	2.2%	2.1%	2.5%	2.5%

All data includes 0% responses.

Total Salary Budget Increases, by Major Metropolitan Area

	Actual 2018		Projected 2019	
	Mean	Median	Mean	Median
National	**2.9%**	**3.0%**	**3.0%**	**3.0%**
Calgary	2.7%	2.8%	2.7%	3.0%
Edmonton	2.6%	2.7%	2.7%	3.0%
Hamilton	2.5%	2.5%	2.6%	2.7%
Montreal	2.8%	2.9%	2.8%	3.0%
Ottawa	2.7%	2.7%	2.7%	2.9%
Quebec	2.6%	2.7%	2.7%	3.0%
Toronto	2.8%	3.0%	2.8%	3.0%
Vancouver	2.7%	2.8%	2.8%	3.0%
Winnipeg	2.6%	2.7%	2.7%	3.0%

Salary Structure Increases, by Employee Category

	Actual 2017		Projected 2018		Actual 2018		Projected 2019	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonmanagement Hourly Nonunion	1.7%	2.0%	1.9%	2.0%	1.8%	2.0%	2.0%	2.0%
Nonmanagement Salaried	1.7%	2.0%	1.9%	2.0%	2.0%	2.0%	2.0%	2.0%
Management Salaried	1.8%	2.0%	1.9%	2.0%	2.0%	2.0%	2.1%	2.0%
Officers/Executives	1.7%	2.0%	1.8%	2.0%	1.9%	2.0%	2.0%	2.0%
All	**1.7%**	**2.0%**	**1.9%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**

All data includes 0% responses.

Global

Salary Budget Increases, by Type of Increase

		Actual 2018		Projected 2019	
	Type of Increase	Mean	Median	Mean	Median
Australia	General Increase/COLA	1.3%	0.2%	1.3%	0.3%
	Merit Increase	2.9%	3.0%	3.0%	3.0%
	Other Increase	0.7%	0.5%	0.8%	0.5%
	Total Increase	**3.2%**	**3.0%**	**3.3%**	**3.0%**
Belgium	General Increase/COLA	1.8%	1.5%	1.5%	1.7%
	Merit Increase	2.0%	2.3%	2.0%	2.3%
	Other Increase	0.7%	0.5%	0.7%	0.5%
	Total Increase	**2.6%**	**2.5%**	**2.5%**	**2.5%**
Brazil	General Increase/COLA	4.2%	4.0%	4.3%	3.2%
	Merit Increase	4.7%	5.0%	4.6%	4.4%
	Other Increase	2.5%	1.7%	2.4%	1.4%
	Total Increase	**5.9%**	**6.0%**	**6.1%**	**6.0%**
China	General Increase/COLA	3.6%	3.0%	3.4%	3.0%
	Merit Increase	6.2%	6.5%	6.3%	6.6%
	Other Increase	1.1%	0.7%	1.1%	0.8%
	Total Increase	**6.6%**	**6.9%**	**6.7%**	**7.0%**
France	General Increase/COLA	1.1%	1.0%	1.0%	0.5%
	Merit Increase	2.4%	2.5%	2.5%	2.5%
	Other Increase	0.7%	0.5%	0.7%	0.5%
	Total Increase	**2.6%**	**2.5%**	**2.7%**	**2.6%**
Germany	General Increase/COLA	1.4%	1.5%	1.3%	0.0%
	Merit Increase	2.8%	3.0%	2.9%	3.0%
	Other Increase	0.8%	0.5%	0.8%	0.5%
	Total Increase	**3.0%**	**3.0%**	**3.1%**	**3.0%**
India	General Increase/COLA	5.4%	5.5%	4.9%	2.5%
	Merit Increase	9.5%	10.0%	9.6%	10.0%
	Other Increase	1.2%	1.0%	1.2%	1.0%
	Total Increase	**10.0%**	**10.0%**	**10.0%**	**10.0%**
Italy	General Increase/COLA	0.9%	0.8%	0.8%	0.5%
	Merit Increase	2.4%	2.5%	2.5%	2.5%
	Other Increase	0.7%	0.5%	0.6%	0.5%
	Total Increase	**2.7%**	**2.6%**	**2.8%**	**2.6%**
Japan	General Increase/COLA	1.1%	0.8%	1.0%	0.1%
	Merit Increase	2.4%	2.4%	2.5%	2.5%
	Other Increase	0.7%	0.5%	0.6%	0.5%
	Total Increase	**2.6%**	**2.5%**	**2.7%**	**2.5%**
Mexico	General Increase/COLA	2.4%	2.5%	1.9%	0.6%
	Merit Increase	4.6%	4.6%	4.7%	4.8%
	Other Increase	1.1%	0.5%	1.2%	0.8%
	Total Increase	**4.9%**	**4.8%**	**5.0%**	**5.0%**

(Continued on page 8)

All data includes 0% responses.

Salary Budget Increases, by Type of Increase *(continued)*

		Actual 2018		Projected 2019	
	Type of Increase	Mean	Median	Mean	Median
Netherlands	General Increase/COLA	1.5%	1.5%	1.5%	1.5%
	Merit Increase	2.6%	2.7%	2.7%	2.8%
	Other Increase	0.6%	0.5%	0.6%	0.5%
	Total Increase	**2.8%**	**2.9%**	**2.9%**	**3.0%**
Russia	General Increase/COLA	3.5%	3.5%	1.9%	0.0%
	Merit Increase	6.9%	7.4%	6.9%	7.4%
	Other Increase	1.0%	0.5%	1.1%	1.0%
	Total Increase	**7.4%**	**7.5%**	**7.3%**	**7.5%**
Singapore	General Increase/COLA	2.0%	2.5%	1.8%	0.4%
	Merit Increase	3.8%	4.0%	3.9%	4.0%
	Other Increase	0.6%	0.5%	0.7%	0.5%
	Total Increase	**4.0%**	**4.0%**	**4.1%**	**4.0%**
Spain	General Increase/COLA	1.4%	1.8%	1.4%	2.0%
	Merit Increase	2.3%	2.3%	2.4%	2.4%
	Other Increase	0.6%	0.5%	0.6%	0.5%
	Total Increase	**2.6%**	**2.5%**	**2.7%**	**2.5%**
Sweden	General Increase/COLA	1.0%	1.0%	1.2%	1.0%
	Merit Increase	2.5%	2.6%	2.6%	2.7%
	Other Increase	0.8%	0.5%	0.8%	0.5%
	Total Increase	**2.8%**	**2.8%**	**2.9%**	**3.0%**
Switzerland	General Increase/COLA	1.3%	1.6%	1.4%	2.0%
	Merit Increase	2.0%	2.0%	2.2%	2.0%
	Other Increase	0.6%	0.5%	0.6%	0.5%
	Total Increase	**2.2%**	**2.0%**	**2.4%**	**2.2%**
United Kingdom	General Increase/COLA	1.5%	1.8%	1.3%	1.0%
	Merit Increase	2.9%	3.0%	2.9%	3.0%
	Other Increase	0.8%	0.5%	0.8%	0.8%
	Total Increase	**3.1%**	**3.0%**	**3.1%**	**3.0%**

Note: "General Increase/COLA," "Merit Increase" and "Other Increase" do not add to the "Total Increase" because not every organization provides all three types of increase. In addition, each type of increase may include multiple responses if each respondent reports for more than one employee category for that type of increase.

All data includes 0% responses.

Total Salary Budget Increases, by Employee Category

		Actual 2018		Projected 2019	
	Employee Category	Mean	Median	Mean	Median
Australia	NHN	3.2%	3.1%	3.3%	3.0%
	NS	3.2%	3.1%	3.3%	3.0%
	MS	3.2%	3.1%	3.3%	3.0%
	OE	3.0%	3.0%	3.0%	3.0%
	All	**3.2%**	**3.0%**	**3.3%**	**3.0%**
Belgium	NHN	2.5%	2.5%	2.6%	2.5%
	NS	2.7%	2.5%	2.6%	2.5%
	MS	2.5%	2.5%	2.5%	2.5%
	OE	2.6%	2.4%	2.3%	2.4%
	All	**2.6%**	**2.5%**	**2.5%**	**2.5%**
Brazil	NHN	6.1%	6.5%	6.4%	6.3%
	NS	5.8%	6.0%	6.1%	6.0%
	MS	5.8%	6.0%	6.0%	6.0%
	OE	5.6%	6.0%	5.8%	6.0%
	All	**5.9%**	**6.0%**	**6.1%**	**6.0%**
China	NHN	6.7%	7.0%	6.8%	7.0%
	NS	6.7%	7.0%	6.8%	7.0%
	MS	6.7%	6.9%	6.8%	7.0%
	OE	6.2%	6.5%	6.3%	6.6%
	All	**6.6%**	**6.9%**	**6.7%**	**7.0%**
France	NHN	2.7%	2.5%	2.8%	2.5%
	NS	2.6%	2.5%	2.7%	2.6%
	MS	2.6%	2.5%	2.7%	2.6%
	OE	2.7%	2.5%	2.7%	2.7%
	All	**2.6%**	**2.5%**	**2.7%**	**2.6%**
Germany	NHN	3.0%	3.0%	3.1%	3.0%
	NS	3.0%	3.0%	3.1%	3.0%
	MS	3.0%	3.0%	3.1%	3.0%
	OE	3.0%	3.0%	3.0%	3.0%
	All	**3.0%**	**3.0%**	**3.1%**	**3.0%**
India	NHN	10.1%	10.0%	10.3%	10.1%
	NS	10.0%	10.0%	10.0%	10.0%
	MS	10.0%	10.0%	10.1%	10.0%
	OE	9.8%	10.0%	9.7%	10.0%
	All	**10.0%**	**10.0%**	**10.0%**	**10.0%**
Italy	NHN	2.6%	2.6%	3.1%	2.7%
	NS	2.7%	2.6%	2.7%	2.6%
	MS	2.7%	2.6%	2.7%	2.7%
	OE	2.6%	2.5%	2.7%	2.6%
	All	**2.7%**	**2.6%**	**2.8%**	**2.6%**
Japan	NHN	2.6%	2.5%	2.7%	2.5%
	NS	2.6%	2.5%	2.7%	2.5%
	MS	2.7%	2.5%	2.8%	2.5%
	OE	2.7%	2.5%	2.5%	2.5%
	All	**2.6%**	**2.5%**	**2.7%**	**2.5%**

NHN Nonmanagement Hourly Nonunion | **NS** Nonmanagement Salaried | **MS** Management Salaried | **OE** Officers/Executives *(Continued on page 10)*

All data includes 0% responses.

Total Salary Budget Increases, by Employee Category *(continued)*

	Employee Category	Actual 2018		Projected 2019	
		Mean	Median	Mean	Median
Mexico	NHN	4.9%	4.9%	5.0%	5.0%
	NS	4.9%	4.8%	5.0%	5.0%
	MS	4.9%	4.8%	5.0%	5.0%
	OE	4.7%	4.7%	4.7%	4.7%
	All	**4.9%**	**4.8%**	**5.0%**	**5.0%**
Netherlands	NHN	2.9%	2.9%	3.0%	3.0%
	NS	2.8%	2.8%	2.9%	3.0%
	MS	2.8%	2.8%	2.9%	3.0%
	OE	3.0%	3.0%	3.1%	3.0%
	All	**2.8%**	**2.9%**	**2.9%**	**3.0%**
Russia	NHN	7.4%	7.7%	7.4%	7.6%
	NS	7.4%	7.5%	7.3%	7.5%
	MS	7.3%	7.5%	7.4%	7.5%
	OE	7.2%	7.5%	6.7%	7.4%
	All	**7.4%**	**7.5%**	**7.3%**	**7.5%**
Singapore	NHN	4.1%	4.0%	4.2%	4.0%
	NS	4.0%	4.0%	4.1%	4.0%
	MS	4.0%	4.0%	4.1%	4.0%
	OE	3.9%	4.0%	4.0%	4.0%
	All	**4.0%**	**4.0%**	**4.1%**	**4.0%**
Spain	NHN	2.5%	2.5%	2.7%	2.5%
	NS	2.5%	2.5%	2.7%	2.5%
	MS	2.6%	2.5%	2.7%	2.5%
	OE	2.6%	2.4%	2.6%	2.5%
	All	**2.6%**	**2.5%**	**2.7%**	**2.5%**
Sweden	NHN	2.8%	2.9%	3.2%	3.0%
	NS	2.8%	2.8%	2.9%	2.9%
	MS	2.8%	2.8%	2.9%	2.9%
	OE	2.9%	2.8%	2.9%	2.9%
	All	**2.8%**	**2.8%**	**2.9%**	**3.0%**
Switzerland	NHN	2.2%	2.1%	2.4%	2.3%
	NS	2.2%	2.0%	2.4%	2.1%
	MS	2.2%	2.0%	2.4%	2.2%
	OE	2.2%	2.0%	2.5%	2.5%
	All	**2.2%**	**2.0%**	**2.4%**	**2.2%**
United Kingdom	NHN	3.1%	3.0%	3.2%	3.0%
	NS	3.1%	3.0%	3.2%	3.0%
	MS	3.1%	3.0%	3.2%	3.0%
	OE	3.0%	3.0%	3.0%	3.0%
	All	**3.1%**	**3.0%**	**3.1%**	**3.0%**

NHN Nonmanagement Hourly Nonunion | **NS** Nonmanagement Salaried | **MS** Management Salaried | **OE** Officers/Executives

All data includes 0% responses.

Please direct any questions or comments to surveypanel@worldatwork.org.

WorldatWork

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WorldatWork
Total Rewards Association

2019 Salary Budget Survey 2020

TOP-LEVEL RESULTS

PUBLISHED JUNE 27, 2019

Below is a high-level look at results from the "WorldatWork 2019-2020 Salary Budget Survey," which closed in May 2019. This year, WorldatWork received a total of 6,090 responses. Additional industry and geographic breakout information for the "WorldatWork 2019-2020 Salary Budget Survey" that can be customized in countless ways for the U.S. and Canada is included in the "Online Reporting Tool," which will be available with the full survey results in early August. Participants will receive a complimentary subscription.

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UNITED STATES

Salary Budget Increases, by Type of Increase

	Actual 2018		Projected 2019		Actual 2019		Projected 2020	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
General Increase/COLA	1.5%	2.0%	1.8%	2.0%	1.7%	2.0%	2.0%	2.5%
Merit Increase	2.8%	3.0%	2.9%	3.0%	2.9%	3.0%	3.0%	3.0%
Other Increase	0.8%	0.5%	0.9%	0.5%	0.9%	0.5%	1.0%	0.8%
Total Increase	**3.1%**	**3.0%**	**3.2%**	**3.0%**	**3.2%**	**3.0%**	**3.3%**	**3.0%**

Note: "General Increase/COLA," "Merit Increase" and "Other Increase" do not add to the "Total Increase" because not every organization provides all three types of increase. In addition, each type of increase may include multiple responses if each respondent reports for more than one employee category for that type of increase.

Total Salary Budget Increases, by Employee Category

	Actual 2018		Projected 2019		Actual 2019		Projected 2020	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonexempt Hourly Nonunion	3.1%	3.0%	3.1%	3.0%	3.2%	3.0%	3.3%	3.0%
Nonexempt Salaried	3.1%	3.0%	3.1%	3.0%	3.1%	3.0%	3.2%	3.0%
Exempt Salaried	3.1%	3.0%	3.2%	3.0%	3.2%	3.0%	3.3%	3.0%
Officers/Executives	3.1%	3.0%	3.2%	3.0%	3.3%	3.0%	3.3%	3.0%
All	**3.1%**	**3.0%**	**3.2%**	**3.0%**	**3.2%**	**3.0%**	**3.3%**	**3.0%**

Total Salary Budget Increases, by State

	Actual 2019		Projected 2020	
	Mean	Median	Mean	Median
National	**3.2%**	**3.0%**	**3.3%**	**3.0%**
Alabama	3.1%	3.0%	3.2%	3.0%
Alaska	3.1%	3.0%	3.1%	3.0%
Arizona	3.2%	3.0%	3.3%	3.0%
Arkansas	3.1%	3.0%	3.2%	3.0%
California	3.2%	3.0%	3.3%	3.0%
Colorado	3.2%	3.0%	3.3%	3.0%
Connecticut	3.2%	3.0%	3.2%	3.0%
Delaware	3.1%	3.0%	3.2%	3.0%
Florida	3.1%	3.0%	3.1%	3.0%
Georgia	3.2%	3.0%	3.2%	3.0%
Hawaii	3.1%	3.0%	3.2%	3.0%
Idaho	3.2%	3.0%	3.2%	3.0%
Illinois	3.2%	3.0%	3.3%	3.0%
Indiana	3.1%	3.0%	3.2%	3.0%
Iowa	3.2%	3.0%	3.2%	3.0%
Kansas	3.1%	3.0%	3.2%	3.0%
Kentucky	3.1%	3.0%	3.1%	3.0%
Louisiana	3.1%	3.0%	3.1%	3.0%
Maine	3.2%	3.0%	3.2%	3.0%
Maryland	3.2%	3.0%	3.2%	3.0%
Massachusetts	3.2%	3.0%	3.2%	3.0%
Michigan	3.1%	3.0%	3.2%	3.0%
Minnesota	3.2%	3.0%	3.2%	3.0%
Mississippi	3.1%	3.0%	3.2%	3.0%
Missouri	3.1%	3.0%	3.2%	3.0%
Montana	3.2%	3.0%	3.2%	3.0%
Nebraska	3.1%	3.0%	3.2%	3.0%
Nevada	3.2%	3.0%	3.2%	3.0%
New Hampshire	3.1%	3.0%	3.1%	3.0%
New Jersey	3.1%	3.0%	3.2%	3.0%
New Mexico	3.2%	3.0%	3.2%	3.0%
New York	3.2%	3.0%	3.2%	3.0%
North Carolina	3.1%	3.0%	3.2%	3.0%
North Dakota	3.2%	3.0%	3.2%	3.0%

	Actual 2019		Projected 2020	
	Mean	Median	Mean	Median
Ohio	3.1%	3.0%	3.2%	3.0%
Oklahoma	3.2%	3.0%	3.2%	3.0%
Oregon	3.2%	3.0%	3.2%	3.0%
Pennsylvania	3.2%	3.0%	3.2%	3.0%
Rhode Island	3.2%	3.0%	3.2%	3.0%
South Carolina	3.1%	3.0%	3.1%	3.0%
South Dakota	3.2%	3.0%	3.2%	3.0%
Tennessee	3.1%	3.0%	3.2%	3.0%
Texas	3.2%	3.0%	3.3%	3.0%
Utah	3.2%	3.0%	3.2%	3.0%
Vermont	3.2%	3.0%	3.2%	3.0%
Virginia	3.2%	3.0%	3.2%	3.0%
Washington	3.3%	3.0%	3.3%	3.0%
West Virginia	3.1%	3.0%	3.2%	3.0%
Wisconsin	3.2%	3.0%	3.2%	3.0%
Wyoming	3.2%	3.0%	3.3%	3.0%

All data includes 0% responses.

Total Salary Budget Increases, by Major Metropolitan Area

	Actual 2019		Projected 2020	
	Mean	Median	Mean	Median
National	**3.2%**	**3.0%**	**3.3%**	**3.0%**
Atlanta	3.2%	3.0%	3.3%	3.0%
Baltimore	2.9%	3.0%	3.1%	3.0%
Boston	3.2%	3.0%	3.2%	3.0%
Chicago	3.1%	3.0%	3.2%	3.0%
Cincinnati	3.0%	3.0%	3.0%	3.0%
Cleveland	3.0%	3.0%	3.0%	3.0%
Dallas	3.2%	3.0%	3.3%	3.0%
Denver	3.3%	3.0%	3.4%	3.0%
Detroit	3.1%	3.0%	3.1%	3.0%
Houston	3.2%	3.0%	3.2%	3.0%
Los Angeles	3.2%	3.0%	3.2%	3.0%
Miami	3.1%	3.0%	3.1%	3.0%
Minneapolis	3.0%	3.0%	3.1%	3.0%

	Actual 2019		Projected 2020	
	Mean	Median	Mean	Median
New York	3.2%	3.0%	3.2%	3.0%
Philadelphia	3.2%	3.0%	3.2%	3.0%
Phoenix	3.2%	3.0%	3.2%	3.0%
Pittsburgh	3.1%	3.0%	3.1%	3.0%
Portland	3.3%	3.0%	3.2%	3.0%
San Diego	3.3%	3.0%	3.2%	3.0%
San Francisco	3.3%	3.0%	3.3%	3.0%
San Jose	3.3%	3.0%	3.3%	3.0%
Seattle	3.3%	3.0%	3.2%	3.0%
St. Louis	3.0%	3.0%	3.0%	3.0%
Tampa	3.1%	3.0%	3.2%	3.0%
Washington, D.C.	3.2%	3.0%	3.2%	3.0%

Merit Increases Awarded, by Performance Category

	High Performers		Middle Performers		Low Performers	
2018	Mean	Median	Mean	Median	Mean	Median
Percentage of employees rated in this category for 2018	27%	25%	67%	70%	5%	4%
Average merit increase awarded to this 2018 performance category	4.1%	4.0%	2.8%	2.8%	0.8%	0.5%
2019						
Percentage of employees estimated to be rated in this category for 2019	26%	23%	68%	70%	6%	5%
Average merit increase estimated for this 2019 performance category	4.2%	4.0%	2.8%	3.0%	0.7%	0.1%

Note: The mean distribution of the percent of employees in each performance category will total 100% or, as a result of rounding, may be very close. However, by definition, the median value for each category will move depending on the frequency of values in the dataset. Therefore, the median distribution of the percent of employees in each category will not equal 100%.

All data includes 0% responses.

Promotional Increases

	2017		2018		2019	
	Mean	Median	Mean	Median	Mean	Median
Percentage of employees that received promotional increases	8.6%	8.0%	8.6%	8.0%	--	--
Percentage of promoted employees' base salary	8.7%	8.5%	8.9%	8.6%	--	--
Planned spending on promotional increases as a percentage of total base salaries	1.6%	1.0%	1.5%	1.0%	1.6%	1.0%

-- Question was not an option in the survey questionnaire.

Salary Structure Increases, by Employee Category

	Actual 2018		Projected 2019		Actual 2019		Projected 2020	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonexempt Hourly Nonunion	2.0%	2.0%	2.1%	2.0%	2.1%	2.0%	2.2%	2.0%
Nonexempt Salaried	2.1%	2.0%	2.1%	2.0%	2.1%	2.0%	2.2%	2.0%
Exempt Salaried	2.1%	2.0%	2.2%	2.0%	2.2%	2.0%	2.2%	2.0%
Officers/Executives	2.0%	2.0%	2.2%	2.0%	2.2%	2.0%	2.2%	2.0%
All	**2.0%**	**2.0%**	**2.1%**	**2.0%**	**2.2%**	**2.0%**	**2.2%**	**2.0%**

Variable Pay Programs, 2018-2020

National	Nonexempt Hourly Nonunion		Nonexempt Salaried		Exempt Salaried		Officers/Executives	
2018	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Average percent budgeted	5.5%	5.0%	6.0%	5.0%	12.6%	12.0%	39.3%	35.4%
Average percent paid	5.6%	5.0%	6.1%	5.0%	13.0%	11.9%	40.6%	35.0%
Percent of employees eligible in 2018 for variable pay	87%	100%	89%	100%	82%	100%	94%	100%
Percent of eligible employees actually paid variable pay for 2018	83%	99%	86%	99%	82%	98%	92%	100%
2019								
Average percent budgeted	5.5%	5.0%	6.1%	5.0%	12.6%	12.0%	39.0%	36.0%
Projected percent paid	5.6%	5.0%	6.1%	5.0%	13.2%	12.0%	40.6%	37.0%
2020								
Projected percent budgeted	5.5%	5.0%	6.0%	5.0%	12.7%	12.0%	38.9%	36.8%

All data includes 0% responses.

CANADA

Salary Budget Increases, by Type of Increase

	Actual 2018		Projected 2019		Actual 2019		Projected 2020	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
General Increase/COLA	1.4%	1.5%	1.6%	2.0%	1.7%	2.0%	1.6%	2.0%
Merit Increase	2.6%	2.8%	2.8%	3.0%	2.7%	3.0%	2.7%	3.0%
Other Increase	0.9%	0.5%	0.9%	0.5%	0.9%	0.5%	0.7%	0.5%
Total Increase	**2.9%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**

Note: "General Increase/COLA," "Merit Increase" and "Other Increase" do not add to the "Total Increase" because not every organization provides all three types of increase. In addition, each type of increase may include multiple responses if each respondent reports for more than one employee category for that type of increase.

Total Salary Budget Increases, by Employee Category

	Actual 2018		Projected 2019		Actual 2019		Projected 2020	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonmanagement Hourly Nonunion	2.8%	3.0%	2.9%	3.0%	2.9%	3.0%	2.9%	3.0%
Nonmanagement Salaried	2.9%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Management Salaried	2.9%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Officers/Executives	2.9%	3.0%	3.0%	3.0%	2.9%	3.0%	2.9%	3.0%
All	**2.9%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**	**3.0%**

Salary Budget Increases, by Province

	Actual 2019		Projected 2020	
	Mean	Median	Mean	Median
National	**3.0%**	**3.0%**	**3.0%**	**3.0%**
Alberta	2.8%	3.0%	2.8%	3.0%
British Columbia	2.9%	3.0%	2.9%	3.0%
Manitoba	2.8%	3.0%	2.9%	3.0%
New Brunswick	2.7%	3.0%	2.8%	3.0%
Newfoundland	2.7%	3.0%	2.8%	3.0%
Northwest Territories	2.7%	3.0%	2.8%	3.0%
Nova Scotia	2.8%	3.0%	2.8%	3.0%
Nunavut	2.7%	3.0%	2.7%	3.0%
Ontario	2.9%	3.0%	2.9%	3.0%
Prince Edward Island	2.6%	2.7%	2.7%	3.0%
Quebec	2.8%	3.0%	2.8%	3.0%
Saskatchewan	2.8%	3.0%	2.8%	3.0%
Yukon	2.5%	2.4%	2.7%	2.8%

All data includes 0% responses.

Total Salary Budget Increases, by Major Metropolitan Area

	Actual 2019		Projected 2020	
	Mean	Median	Mean	Median
National	**3.0%**	**3.0%**	**3.0%**	**3.0%**
Calgary	2.7%	3.0%	2.7%	3.0%
Edmonton	2.7%	3.0%	2.7%	3.0%
Hamilton	2.7%	2.8%	2.8%	3.0%
Montreal	2.8%	3.0%	2.9%	3.0%
Ottawa	2.7%	2.8%	2.8%	3.0%
Quebec	2.8%	3.0%	2.8%	3.0%
Toronto	3.0%	3.0%	3.0%	3.0%
Vancouver	2.9%	3.0%	2.9%	3.0%
Winnipeg	2.6%	2.8%	2.6%	3.0%

Salary Structure Increases, by Employee Category

	Actual 2018		Projected 2019		Actual 2019		Projected 2020	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Nonmanagement Hourly Nonunion	1.8%	2.0%	2.0%	2.0%	2.0%	2.0%	2.1%	2.0%
Nonmanagement Salaried	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.1%	2.0%
Management Salaried	2.0%	2.0%	2.1%	2.0%	2.0%	2.0%	2.1%	2.0%
Officers/Executives	1.9%	2.0%	2.0%	2.0%	2.1%	2.0%	2.1%	2.0%
All	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.1%**	**2.0%**

All data includes 0% responses.

GLOBAL

Salary Budget Increases, by Type of Increase

		Actual 2019		Projected 2020	
	Type of Increase	Mean	Median	Mean	Median
Australia	General Increase/COLA	2.3%	2.6%	2.2%	2.6%
	Merit Increase	2.9%	3.0%	3.0%	3.0%
	Other Increase	0.9%	0.5%	0.8%	0.6%
	Total Increase	**3.2%**	**3.0%**	**3.2%**	**3.0%**
Belgium	General Increase/COLA	1.8%	2.0%	1.9%	2.0%
	Merit Increase	1.8%	2.3%	2.1%	2.5%
	Other Increase	1.0%	0.7%	0.9%	0.5%
	Total Increase	**2.5%**	**2.5%**	**2.6%**	**2.6%**
Brazil	General Increase/COLA	4.0%	4.2%	3.9%	4.5%
	Merit Increase	4.2%	4.0%	4.3%	4.0%
	Other Increase	2.0%	1.0%	1.7%	1.0%
	Total Increase	**5.4%**	**5.5%**	**5.5%**	**5.7%**
China	General Increase/COLA	3.9%	5.0%	3.6%	5.0%
	Merit Increase	6.2%	6.5%	6.2%	6.5%
	Other Increase	1.1%	1.0%	1.0%	1.0%
	Total Increase	**6.8%**	**6.8%**	**6.8%**	**6.8%**
France	General Increase/COLA	1.6%	1.8%	1.6%	1.5%
	Merit Increase	2.4%	2.5%	2.5%	2.5%
	Other Increase	0.8%	0.5%	0.7%	0.5%
	Total Increase	**2.7%**	**2.5%**	**2.7%**	**2.5%**
Germany	General Increase/COLA	2.1%	2.5%	2.0%	2.5%
	Merit Increase	2.9%	3.0%	2.9%	3.0%
	Other Increase	0.8%	0.5%	0.9%	0.5%
	Total Increase	**3.1%**	**3.0%**	**3.2%**	**3.0%**
India	General Increase/COLA	5.4%	7.0%	5.5%	8.0%
	Merit Increase	9.6%	10.0%	9.6%	10.0%
	Other Increase	1.4%	1.0%	1.1%	1.0%
	Total Increase	**9.9%**	**10.0%**	**9.9%**	**10.0%**
Italy	General Increase/COLA	1.3%	1.0%	1.2%	1.0%
	Merit Increase	2.4%	2.5%	2.4%	2.5%
	Other Increase	0.7%	0.5%	0.7%	0.5%
	Total Increase	**2.6%**	**2.5%**	**2.7%**	**2.6%**
Japan	General Increase/COLA	1.7%	2.0%	1.5%	2.0%
	Merit Increase	2.4%	2.5%	2.4%	2.5%
	Other Increase	0.7%	0.5%	0.7%	0.5%
	Total Increase	**2.6%**	**2.5%**	**2.7%**	**2.5%**
Mexico	General Increase/COLA	3.2%	4.0%	2.9%	4.0%
	Merit Increase	4.8%	5.0%	4.9%	5.0%
	Other Increase	0.9%	0.8%	0.9%	0.6%
	Total Increase	**5.1%**	**5.0%**	**5.1%**	**5.0%**

(Continued on page 8)

All data includes 0% responses.

Salary Budget Increases, by Type of Increase *(continued)*

		Actual 2019		Projected 2020	
	Type of Increase	Mean	Median	Mean	Median
Netherlands	General Increase/COLA	2.0%	2.5%	2.0%	2.5%
	Merit Increase	2.6%	2.8%	2.7%	2.8%
	Other Increase	0.8%	0.5%	0.7%	0.5%
	Total Increase	**3.0%**	**2.9%**	**3.0%**	**3.0%**
Russia	General Increase/COLA	3.1%	3.5%	3.4%	4.3%
	Merit Increase	6.4%	7.0%	6.7%	7.2%
	Other Increase	1.0%	1.0%	0.9%	1.0%
	Total Increase	**6.7%**	**7.0%**	**6.9%**	**7.2%**
Singapore	General Increase/COLA	3.1%	3.5%	2.6%	3.3%
	Merit Increase	3.8%	4.0%	3.8%	4.0%
	Other Increase	0.8%	0.6%	0.7%	0.5%
	Total Increase	**4.0%**	**4.0%**	**4.1%**	**4.0%**
Spain	General Increase/COLA	1.4%	1.7%	1.4%	1.7%
	Merit Increase	2.4%	2.5%	2.4%	2.5%
	Other Increase	0.7%	0.5%	0.6%	0.5%
	Total Increase	**2.7%**	**2.5%**	**2.7%**	**2.5%**
Sweden	General Increase/COLA	1.4%	2.0%	1.5%	2.0%
	Merit Increase	2.6%	2.7%	2.5%	2.7%
	Other Increase	0.8%	0.5%	0.7%	0.5%
	Total Increase	**2.8%**	**2.8%**	**2.7%**	**2.8%**
Switzerland	General Increase/COLA	2.0%	2.0%	2.0%	2.0%
	Merit Increase	2.1%	2.0%	2.1%	2.0%
	Other Increase	0.6%	0.5%	0.6%	0.5%
	Total Increase	**2.3%**	**2.2%**	**2.3%**	**2.2%**
United Kingdom	General Increase/COLA	2.1%	2.5%	1.9%	2.5%
	Merit Increase	2.8%	3.0%	2.8%	3.0%
	Other Increase	0.8%	0.5%	0.7%	0.5%
	Total Increase	**3.1%**	**3.0%**	**3.1%**	**3.0%**

Note: "General Increase/COLA," "Merit Increase" and "Other Increase" do not add to the "Total Increase" because not every organization provides all three types of increase. In addition, each type of increase may include multiple responses if each respondent reports for more than one employee category for that type of increase.

All data includes 0% responses.

Total Salary Budget Increases, by Employee Category

		Actual 2019		Projected 2020	
	Employee Category	Mean	Median	Mean	Median
Australia	NHN	3.1%	3.0%	3.2%	3.0%
	NS	3.1%	3.0%	3.2%	3.0%
	MS	3.1%	3.0%	3.2%	3.0%
	OE	3.4%	3.0%	3.2%	3.0%
	All	**3.2%**	**3.0%**	**3.2%**	**3.0%**
Belgium	NHN	2.5%	2.5%	2.8%	2.7%
	NS	2.5%	2.5%	2.6%	2.6%
	MS	2.5%	2.5%	2.6%	2.6%
	OE	2.4%	2.5%	2.4%	2.5%
	All	**2.5%**	**2.5%**	**2.6%**	**2.6%**
Brazil	NHN	5.1%	5.3%	5.1%	5.4%
	NS	5.3%	5.5%	5.4%	5.7%
	MS	5.5%	5.5%	5.5%	5.7%
	OE	5.7%	5.9%	5.8%	5.9%
	All	**5.4%**	**5.5%**	**5.5%**	**5.7%**
China	NHN	6.9%	6.8%	6.8%	6.8%
	NS	6.8%	6.8%	6.7%	6.8%
	MS	6.7%	6.8%	6.7%	6.8%
	OE	6.6%	6.6%	6.9%	7.0%
	All	**6.8%**	**6.8%**	**6.8%**	**6.8%**
France	NHN	2.7%	2.5%	2.8%	2.5%
	NS	2.7%	2.5%	2.8%	2.6%
	MS	2.7%	2.5%	2.7%	2.5%
	OE	2.8%	2.5%	2.7%	2.5%
	All	**2.7%**	**2.5%**	**2.7%**	**2.5%**
Germany	NHN	3.2%	3.0%	3.6%	3.0%
	NS	3.1%	3.0%	3.1%	3.0%
	MS	3.1%	3.0%	3.1%	3.0%
	OE	3.1%	3.0%	3.1%	3.0%
	All	**3.1%**	**3.0%**	**3.2%**	**3.0%**
India	NHN	9.5%	10.0%	9.7%	10.0%
	NS	10.0%	10.0%	10.0%	10.0%
	MS	9.8%	10.0%	9.8%	10.0%
	OE	10.5%	10.0%	9.8%	10.0%
	All	**9.9%**	**10.0%**	**9.9%**	**10.0%**
Italy	NHN	2.6%	2.5%	2.7%	2.5%
	NS	2.7%	2.5%	2.7%	2.6%
	MS	2.7%	2.5%	2.7%	2.6%
	OE	2.5%	2.5%	2.6%	2.5%
	All	**2.6%**	**2.5%**	**2.7%**	**2.6%**
Japan	NHN	2.6%	2.5%	2.7%	2.5%
	NS	2.6%	2.5%	2.6%	2.5%
	MS	2.6%	2.5%	2.6%	2.5%
	OE	2.7%	2.5%	2.7%	2.5%
	All	**2.6%**	**2.5%**	**2.7%**	**2.5%**

NHN Nonmanagement Hourly Nonunion | **NS** Nonmanagement Salaried | **MS** Management Salaried | **OE** Officers/Executives *(Continued on page 10)*

All data includes 0% responses.

Total Salary Budget Increases, by Employee Category *(continued)*

	Employee Category	Actual 2019 Mean	Actual 2019 Median	Projected 2020 Mean	Projected 2020 Median
Mexico	NHN	5.2%	5.0%	5.2%	5.0%
	NS	5.1%	5.0%	5.2%	5.0%
	MS	5.1%	5.0%	5.2%	5.0%
	OE	4.8%	5.0%	4.9%	5.0%
	All	**5.1%**	**5.0%**	**5.1%**	**5.0%**
Netherlands	NHN	2.9%	2.8%	3.0%	3.0%
	NS	2.9%	2.9%	3.0%	3.0%
	MS	2.9%	2.9%	2.9%	3.0%
	OE	3.1%	3.0%	3.0%	3.0%
	All	**3.0%**	**2.9%**	**3.0%**	**3.0%**
Russia	NHN	6.6%	7.0%	6.7%	7.0%
	NS	6.8%	7.1%	7.0%	7.4%
	MS	6.7%	7.2%	7.0%	7.3%
	OE	6.5%	7.0%	6.6%	7.0%
	All	**6.7%**	**7.0%**	**6.9%**	**7.2%**
Singapore	NHN	4.4%	4.0%	4.4%	4.0%
	NS	4.0%	4.0%	4.0%	4.0%
	MS	4.0%	4.0%	4.0%	4.0%
	OE	4.1%	4.0%	4.2%	4.0%
	All	**4.0%**	**4.0%**	**4.1%**	**4.0%**
Spain	NHN	2.7%	2.5%	2.9%	2.5%
	NS	2.7%	2.5%	2.6%	2.5%
	MS	2.6%	2.5%	2.6%	2.5%
	OE	2.6%	2.5%	2.6%	2.5%
	All	**2.7%**	**2.5%**	**2.7%**	**2.5%**
Sweden	NHN	2.8%	2.7%	2.8%	2.7%
	NS	2.8%	2.8%	2.8%	2.8%
	MS	2.8%	2.8%	2.7%	2.8%
	OE	2.8%	2.8%	2.6%	2.6%
	All	**2.8%**	**2.8%**	**2.7%**	**2.8%**
Switzerland	NHN	2.5%	2.3%	2.5%	2.4%
	NS	2.3%	2.2%	2.3%	2.2%
	MS	2.3%	2.2%	2.3%	2.2%
	OE	2.3%	2.2%	2.3%	2.2%
	All	**2.3%**	**2.2%**	**2.3%**	**2.2%**
United Kingdom	NHN	3.1%	3.0%	3.1%	3.0%
	NS	3.1%	3.0%	3.1%	3.0%
	MS	3.1%	3.0%	3.1%	3.0%
	OE	3.0%	3.0%	3.0%	3.0%
	All	**3.1%**	**3.0%**	**3.1%**	**3.0%**

NHN Nonmanagement Hourly Nonunion | **NS** Nonmanagement Salaried | **MS** Management Salaried | **OE** Officers/Executives

All data includes 0% responses.

Please direct any questions or comments to surveypanel@worldatwork.org.

WorldatWork Total Rewards Association

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OPUC Data Request 123

Referring to the Company's response to SDR 92, for the Test Year 2021, please break out separately the amount of Officer compensation from the Exempt compensation similarly to the responses for the prior year actuals.

1st Supplemental Response to OPUC Data Request 123

In further support of the PacifiCorp's March 12, 2020 response, the Company provides the following supplemental response:

Please refer to Attachment OPUC 123 -1st Supplemental for a breakout of the estimated compensation amounts for the Name Executive Officers included in the Test Year 2021.

The test year Annual Incentive Plan (AIP) amount has been updated to reflect the change to the AIP plan beginning in 2018. This update will be reflected in the Company's rebuttal filing in this case.

OPUC Data Request 123

Referring to the Company's response to SDR 92, for the Test Year 2021, please break out separately the amount of Officer compensation from the Exempt compensation similarly to the responses for the prior year actuals.

Response to OPUC Data Request 123

Named Executive Officer (NEO) costs associated with wages, salaries and bonuses are not tracked by individual nor recorded as a separate category of expense in the company's accounting system. For purposes of providing comparable data for the previous years in Standard Data Request OPUC 092, the test year salary and wages expense calculated all exempt employees (including NEOs) using an escalation factor to determine the test year 2021.

2019 Annual Incentive Plan

Introduction and Objectives

PacifiCorp's Annual Incentive Plan provides incentive awards to reward employees for achieving objective targets (as measured by scorecards) and the contributions for advancing the business. Awards will be made based upon measurable achievement of results. This approach supports the philosophy of incentive compensation as pay at risk that is earned based on the company, department and individual performance.

Plan Details

Eligibility

- All regular, full and part-time nonrepresented employees of PacifiCorp, in exempt jobs grade 14 and up, are eligible to participate in the Annual Incentive Plan (AIP). All non-exempt jobs are not eligible for participation in the Annual Incentive Plan.

- A participant must be employed in an incentive-eligible position prior to Oct. 1, 2019 to be eligible to receive an award. Any employee hired on or after Oct. 1, 2019 is not eligible.

- Employees who are employed for less than the plan term due to retirement (as defined by the company) or disability will be considered eligible and may receive a prorated award at the discretion of management, reflective of achievement of goals, company and individual performance, and other factors.

    - Employees who are on a qualified leave during the plan term will be eligible for participation in the plan.

- Employees who are employed for less than the plan term due to a termination for cause, voluntary resignation, reduction in force, are affiliated with the Hiring Hall, are contractors or are bargaining unit employees are ineligible for participation.

- For employees who are deceased during the plan year, the incentive award will be paid on the next available payroll. The amount will be prorated based on eligible earnings and will be paid at 85% of the employee's target.

Please note:

- *Award recipients who are "inactive" but eligible (retirees/disability) can expect to receive their awards approximately two weeks after active employees.*
- *Bargaining unit and all non-exempt and exempt jobs through grade 13 employees who transfer into incentive-eligible positions must have been employed in their incentive-eligible positions prior to Oct. 1, 2019 in order to be eligible for participation.*
- *Those transferring from bargaining unit and non-exempt and exempt jobs through grade 13, to incentive-eligible positions will have their awards calculated based on eligible earnings while in incentive-eligible positions only. (Earnings accumulated while occupying bargaining unit jobs or non-eligible incentive positions will NOT be considered as eligible earnings for the purposes of incentive payment.)*

Plan Term

The plan term is Jan. 1, 2019 through Dec. 31, 2019.

Plan Components

All eligible participants will have an award opportunity based upon company, department and individual performance.

Employees with a scorecard:

Employees without a scorecard:

1. Employees without scorecards will be calculated based on the scorecard of their closest manager

Recommended incentive awards will be reviewed by each president and a final decision made in collaboration with senior management prior to final award determination.

Eligible Earnings

For full plan year participants, awards under the plan will be based on the greater of eligible earnings or annualized salary, as described below. For partial year participation and part-time employees, awards will be based on eligible earnings only.

- Regular pay
- Overtime pay

Please note:

- Pre-tax 401(k) employee deferrals, insurance plan contributions, and reimbursement account deductions are not subtracted from eligible earnings.
- Bonuses of any kind are not considered part of eligible earnings for the purposes of AIP calculation.

Payment of Awards

Payment is targeted for the week of Dec. 16, 2019, pending approvals.

Term, Amendment and Termination of the Plan

This plan is discretionary and can be terminated or modified by PacifiCorp with or without cause or notice.

This plan, and any award hereunder, is not a contract of employment and nothing in this document is intended to guarantee a fixed term of employment, a specific level of income, an award or any other terms or conditions of employment.

2020 Annual Incentive Plan

Introduction and Objectives

PacifiCorp's Annual Incentive Plan provides incentive awards to reward employees for achieving objective targets (as measured by scorecards) and the contributions for advancing the business. Awards will be made based upon measurable achievement of results. This approach supports the philosophy of incentive compensation as pay at risk that is earned based on the company, department and individual performance.

Plan Details

Eligibility

- All regular, full and part-time nonrepresented employees of PacifiCorp, in exempt jobs grade 14 and up, are eligible to participate in the Annual Incentive Plan (AIP). All non-exempt jobs are not eligible for participation in the Annual Incentive Plan.

- A participant must be employed in an incentive-eligible position prior to Oct. 1, 2020 to be eligible to receive an award. Any employee hired on or after Oct. 1, 2020 is not eligible.

- Employees who are employed for less than the plan term due to retirement (as defined by the company) or disability will be considered eligible and may receive a prorated award at the discretion of management, reflective of achievement of goals, company and individual performance, and other factors.

    - Employees who are on a qualified leave during the plan term will be eligible for participation in the plan.

- Employees who are employed for less than the plan term due to a termination for cause, voluntary resignation, reduction in force, are affiliated with the Hiring Hall, are contractors or are bargaining unit employees are ineligible for participation.

- For employees who are deceased during the plan year, the incentive award will be paid on the next available payroll. The amount will be prorated based on eligible earnings and will be paid at 85% of the employee's target.

Please note:

- *Award recipients who are "inactive" but eligible (retirees/disability) can expect to receive their awards approximately two weeks after active employees.*
- *Bargaining unit and all non-exempt and exempt jobs through grade 13 employees who transfer into incentive-eligible positions must have been employed in their incentive-eligible positions prior to Oct. 1, 2020 in order to be eligible for participation.*
- *Those transferring from bargaining unit and non-exempt and exempt jobs through grade 13, to incentive-eligible positions will have their awards calculated based on eligible earnings while in incentive-eligible positions only. (Earnings accumulated while occupying bargaining unit jobs or non-eligible incentive positions will NOT be considered as eligible earnings for the purposes of incentive payment.)*

Plan Term

The plan term is Jan. 1, 2020 through Dec. 31, 2020.

Plan Components

All eligible participants will have an award opportunity based upon company, department and individual performance.

Employees with a scorecard:

Employees without a scorecard:

1. Employees without scorecards will be calculated based on the scorecard of their closest manager

Recommended incentive awards will be reviewed by each president and a final decision made in collaboration with senior management prior to final award determination.

Eligible Earnings

For full plan year participants, awards under the plan will be based on the greater of eligible earnings or annualized salary, as described below. For partial year participation and part-time employees, awards will be based on eligible earnings only.

- Regular pay
- Overtime pay

Please note:

- Pre-tax 401(k) employee deferrals, insurance plan contributions, and reimbursement account deductions are not subtracted from eligible earnings.
- Bonuses of any kind are not considered part of eligible earnings for the purposes of AIP calculation.

Payment of Awards

Payment is targeted for the week of Dec. 14, 2020, pending approvals.

Term, Amendment and Termination of the Plan

This plan is discretionary and can be terminated or modified by PacifiCorp with or without cause or notice.

This plan, and any award hereunder, is not a contract of employment and nothing in this document is intended to guarantee a fixed term of employment, a specific level of income, an award or any other terms or conditions of employment.

OPUC Data Request 125

Is AIP the only incentive/bonus (incentive) program included in the Company's filed Oregon allocated 2021 Test Year or base year? If not, please include:

(a) A narrative of all included incentive programs by eligible employee categories;

(b) Point to all testimony and work papers regarding the Company's incentive programs;

(c) A copy of the plans and any documents provided to employees in 2019 and 2020 regarding how any incentive earned or expected to be earned was determined or would be determined by employee category;

(d) The amounts included in the Oregon allocated test year or base year by incentive program and by employee category;

(e) A clear explanation of how each incentive in the Oregon allocated test year or base year is measured and whether it is merit based (e.g. safety, customer metrics; benefits both shareholders and customers) or performance based (e.g. ROE, financial metrics; benefit shareholders); and,

(f) An explanation of whether any amount of an incentive in the Oregon allocated base year was excluded from the Oregon allocated test year based on the Oregon Commission's policy to disallow 100 percent of officer incentives and 75 percent of non-officer performance based incentives and 50 percent of merit based incentives. If so, please provide the total amount of incentives in the base year by employee category, incentive program and the amount excluded from the Oregon allocated test year by incentive program and employee category.

(Please note that the above reference to incentives also includes stock options or restricted stock.)

Response to OPUC Data Request 125

No, the annual incentive plan (AIP) is not the only incentive program included in the Company's filed Oregon-allocated 2021 test year or base year.

(a) Other programs include other bonuses and awards available to employees from time to time that may include line items such as employee recognition awards, training awards, hire-in bonuses, Stars award program, and safety

award program.

(b) Please refer to the direct testimony of Shelley E. McCoy, Exhibit PAC/1300, page 15 for a summary of the Company's Wage and Employee Benefits adjustment, as well as Adjustment 4.2 – Wage and Employee Benefits in Exhibit PAC/1302, for testimony related to incentives.

(c) Please refer to Attachment OPUC 125-1 and Attachment OPUC 125-2.

(d) Please refer to Company responses to Standard Data Request OPUC 092 and OPUC Data Request 124.

(e) Please refer to the Company's response to subpart (c) of this data request above.

(f) Both the Supplemental Executive Retirement Plan (SERP) and Long Term Incentive Plan (LTIP) amounts are excluded from the Oregon-allocated test year. LTIP is also excluded from the base year. SERP expenses of $2.9 million included in the base year are removed in Adjustment 4.2, Wage and Employee Benefits, as can be seen on page 4.2.2 of Exhibit PAC/1302.

OPUC Data Request 171

See PAC/1000, Vail/51, lines 14-15. Please further elaborate on the statement, "It should be noted that the required energy output greatly exceeded the available energy input."

Response to OPUC Data Request 171

The energy storage device would need to be capable of providing 15 megavolt ampere (MVA) discharge capacity from roughly 6:00 a.m. until 10:00 p.m. based on a peak winter day load profile. This equates to up to 240 megavolt ampere hour (MVAh) of energy (15 MVA multiplied by 16 hours) that would need to be stored in the device prior to 6:00 a.m. daily in preparation of the potential discharge requirement. The available time to charge the device during the nighttime hours is estimated at five hours, with a peak demand that avoids equipment overloads of approximately 25 MVA. The amount of energy that can be stored during that period is 125 MVAh (25 MVA multiplied by five hours) which is significantly lower than the 240 MVAh discharge capability that would be required in order for an energy storage device to be a viable alternative.

OPUC Data Request 178

In an excel spreadsheet, with all cell references and formulae intact, for each of the years 2014 through 2019, inclusive, please provide the following information as formatted in the table below on a total Company and Oregon basis: This request for 2019 is ongoing.

a. Average number of FTE's;
b. Severance costs;
c. Annual incentive payments;
d. Annual wages and salaries cost;
e. Annual overtime cost; and,
f. Annual payroll tax cost.

	2014	**2015**	**2016**	**2017**	**2018**	**2019**
NEO						
Other Executives						
Senior Management						
Other Management (Supervisor)						
Other Exempt						
Non-Exempt						
Union						
Total						

Response to OPUC Data Request 178

Please refer to Attachment OPUC 178 for total company information for (a) through (f) for calendar years 2014 through 2019.

PacifiCorp does not maintain wages and full time equivalent (FTE) information by the employee groups listed in the request, but has made efforts to categorize such information by Named Executive Officer (NEO), Exempt employees, Non-Exempt and Non-Union and Union employee categories.

Costs associated with wages, salaries and payroll taxes are charged to numerous accounts and to acquire such data on an Oregon basis would result in copious time

and voluminous data. For the purposes of allocating costs to an Oregon-allocated basis, the company applies allocation factors calculated using the prevailing jurisdictional allocation protocol approved for each respective calendar year.

OPUC Data Request 179

Please provide a copy of PacifiCorp's Compensation Incentive Plans (please provide a detailed explanation of any ROE targets, financial targets, performance targets, and awards contained in any current long-term incentive plan).

Response to OPUC Data Request 179

The 2020 Annual Incentive Plan (AIP) document, provided as Attachment OPUC 179-1, outlines PacifiCorp's incentive program details. All eligible AIP participants will have an award opportunity based upon company, department, and individual performance.

For 2019, the company performance was based on the achievement of the goals identified in the 2019 PacifiCorp scorecard, provided as Confidential Attachment OPUC 179-2. Please also see Attachment OPUC 179-3 for a description of the 2019 PacifiCorp scorecard program.

In addition to the AIP, PacifiCorp may grant cash performance awards periodically during the year to employees to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary. Performance awards are also provided in the form of a spot award program called STARS. STARS awards are provided to employees on an informal basis throughout the year for efforts and performance that went above and beyond the employee's normal job requirements and expectations. Please see Attachment OPUC 179-4 for a matrix that outlines the different levels of awards and eligibility of the STARS program.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

2020 Annual Incentive Plan

Introduction and Objectives

PacifiCorp's Annual Incentive Plan provides incentive awards to reward employees for achieving objective targets (as measured by scorecards) and the contributions for advancing the business. Awards will be made based upon measurable achievement of results. This approach supports the philosophy of incentive compensation as pay at risk that is earned based on the company, department and individual performance.

Plan Details

Eligibility

- All regular, full and part-time nonrepresented employees of PacifiCorp, in exempt jobs grade 14 and up, are eligible to participate in the Annual Incentive Plan (AIP). All non-exempt jobs are not eligible for participation in the Annual Incentive Plan.

- A participant must be employed in an incentive-eligible position prior to Oct. 1, 2020 to be eligible to receive an award. Any employee hired on or after Oct. 1, 2020 is not eligible.

- Employees who are employed for less than the plan term due to retirement (as defined by the company) or disability will be considered eligible and may receive a prorated award at the discretion of management, reflective of achievement of goals, company and individual performance, and other factors.

    - Employees who are on a qualified leave during the plan term will be eligible for participation in the plan.

- Employees who are employed for less than the plan term due to a termination for cause, voluntary resignation, reduction in force, are affiliated with the Hiring Hall, are contractors or are bargaining unit employees are ineligible for participation.

- For employees who are deceased during the plan year, the incentive award will be paid on the next available payroll. The amount will be prorated based on eligible earnings and will be paid at 85% of the employee's target.

Please note:

- *Award recipients who are "inactive" but eligible (retirees/disability) can expect to receive their awards approximately two weeks after active employees.*
- *Bargaining unit and all non-exempt and exempt jobs through grade 13 employees who transfer into incentive-eligible positions must have been employed in their incentive-eligible positions prior to Oct. 1, 2020 in order to be eligible for participation.*
- *Those transferring from bargaining unit and non-exempt and exempt jobs through grade 13, to incentive-eligible positions will have their awards calculated based on eligible earnings while in incentive-eligible positions only. (Earnings accumulated while occupying bargaining unit jobs or non-eligible incentive positions will NOT be considered as eligible earnings for the purposes of incentive payment.)*

Plan Term

The plan term is Jan. 1, 2020 through Dec. 31, 2020.

Plan Components

All eligible participants will have an award opportunity based upon company, department and individual performance.

Employees with a scorecard:

Employees without a scorecard:

1. Employees without scorecards will be calculated based on the scorecard of their closest manager

Recommended incentive awards will be reviewed by each president and a final decision made in collaboration with senior management prior to final award determination.

Eligible Earnings

For full plan year participants, awards under the plan will be based on the greater of eligible earnings or annualized salary, as described below. For partial year participation and part-time employees, awards will be based on eligible earnings only.

- Regular pay
- Overtime pay

Please note:

- Pre-tax 401(k) employee deferrals, insurance plan contributions, and reimbursement account deductions are not subtracted from eligible earnings.
- Bonuses of any kind are not considered part of eligible earnings for the purposes of AIP calculation.

Payment of Awards

Payment is targeted for the week of Dec. 14, 2020, pending approvals.

Term, Amendment and Termination of the Plan

This plan is discretionary and can be terminated or modified by PacifiCorp with or without cause or notice.

This plan, and any award hereunder, is not a contract of employment and nothing in this document is intended to guarantee a fixed term of employment, a specific level of income, an award or any other terms or conditions of employment.

PacifiCorp Scorecard

The PacifiCorp scorecard was developed with key performance indicators (KPIs) in each of the core principles, with the core principles equally weighted. Targets were established to advance the business and demonstrate continuous improvement.

Vice Presidents and President Direct Reports

All vice presidents and president direct reports will have a scorecard, regardless of whether they have direct reports. Vice president and president direct scorecards will have a KPI in each of the core principles, with the core principles equally weighted. Individual KPIs within each core principle are not required to be equally weighted. Every KPI will have a direct link to the PacifiCorp scorecard.

Manager Scorecards

All managers with one or more direct reports will have a scorecard (with some exceptions noted below). Manager scorecards are not required to have a KPI in every core principle. However, where a scorecard has less than the six core principles, the scorecard must equally weight the applicable core principles (e.g. scorecard with KPI in five core principles, each core principle is weighted at 20%). Individual KPIs within each core principle are not required to be equally weighted. Every KPI will have a direct link to the PacifiCorp scorecard.

Individual Contributors

Individual contributors, with the exception of vice presidents, will not have a scorecard. Functional managers and managers without direct reports are considered individual contributors.

Exceptions

The following managers will not have scorecards:

- Bridger Coal Company managers, with the exception of the General Manager, Mines
- Thermal generation front-line supervisors (supervising represented workforce)

Annual Incentive Plan

Scorecard results form the basis for the annual incentive plan award for PacifiCorp.

STARS

	Level 1 Thank-You Card	Level 2 Gift Cards $50	Level 3 Cash Awards Over $50
Reason/Criteria	Recognition and thank you to an individual for a job well done, or for providing extra assistance for a short duration.	Recognition of individual for effort and/or results above expectations for a short duration or one-time event. Generally, the impact is limited to the workgroup or department. May also be in recognition of demonstrated behavior that has had a positive impact.	Recognition of individual for work performed above job expectations with impact to the business reflected in the award levels.
Recipient	Full or part-time employees (Contractors are not eligible.)	Full or part-time employees (Contractors are not eligible.)	Full or part-time non-represented employees (Represented employees and contractors are not eligible.)
Nominated By	Anyone	Anyone, with direct supervisor approval	Anyone, with required approvals
Approval	None	Employee's supervisor or above	• Employee's direct supervisor • VP (for awards up to and including $750) • CEO, President (for awards over $750)
Award		$50 gift card (Reflected on employee's pay stub; grossed up for taxes)	Cash (Awards up to $1,000 will be grossed up for taxes.)
Expected Frequency	Frequent	Periodic/As earned	Smaller awards – more frequently; Larger – less frequently, given for more significant contributions
Process **Refer to How-To Guide**	• Obtain thank-you card from STARS Administrator or from various work locations (or use electronic form) • Fill out and give to recipient	• Complete STARS Level 2 Nomination Form • Obtain nominee's supervisor approval • Give form to recipient • Recipient redeems with STARS Administrator for a gift card	• Complete STARS Level 3 Nomination Form • Obtains required approvals, depending on the award amount • Email to STARS • Payroll will contact nominator/supervisor once approved to discuss timing • Please allow up to two weeks for processing.

Questions? Email STARS.

OPUC Data Request 180

Is AIP the only incentive/bonus (incentive) program included in the Company's filed Oregon allocated 2021 Test Year or base year? If not, please include:

a. A narrative of all included incentive programs by eligible employee categories;
b. Point to all testimony and workpapers regarding the Company's incentive programs;
c. A copy of the plans and any documents provided to employees in 2019 and 2020 regarding how any incentive earned or expected to be earned was determined or would be determined by employee category;
d. The amounts included in the Oregon allocated test year or base year by incentive program and by employee category;
e. A clear explanation of how each incentive in the Oregon allocated test year or base year is measured and whether it is merit based (e.g. safety, customer metrics; benefits both shareholders and customers) or performance based (e.g. ROE, financial metrics; benefit shareholders); and,
f. An explanation of whether any amount of an incentive in the Oregon allocated base year was excluded from the Oregon allocated test year based on the Oregon Commission's policy to disallow 100 percent of officer incentives and 75 percent of non-officer performance based incentives and 50 percent of merit based incentives. If so, please provide the total amount of incentives in the base year by employee category, incentive program and the amount excluded from the Oregon allocated test year by incentive program and employee category.

(Please note that the above reference to incentives also includes stock options or restricted stock.)

Response to OPUC Data Request 180

a.-f. Please refer to the Company's response to OPUC Data Request 125 in this docket.

OPUC Data Request 241

Please provide Staff with the current union contract for Oregon unions. If the contract is under negotiation, please provide when finalized.

Response to OPUC Data Request 241

Labor costs are system allocated, therefore the Company is responding with information for all PacifiCorp unions, not just those that represent Oregon-based employees.

Please refer to Confidential Attachments OPUC 241-1 through 241-7.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 242

Please provide staff with average Oregon union increases per year for calendar years 2017, 2018, 2019, 2020.

Response to OPUC Data Request 242

Labor costs are system allocated, therefore the Company is responding with information for all PacifiCorp unions, not just those that represent Oregon-based employees.

Please refer to Attachment OPUC 242 for the annual estimated increase in union wages for calendar years 2017, 2018, 2019 and up through March 31, 2020. Please note that some unions occur in more states than just Oregon. In these cases, it is not possible to breakout Oregon's share of increases.

OPUC Data Request 275

In DR 123, please explain the large decrease in Officer incentives from the base year ($2.2 million, 2019) to the test year ($150k).

Response to OPUC Data Request 275

The difference is that the base year is based on the actual Annual Incentive Plan, whereas the test year is a calculation based on the average payout percentage for all eligible employees for calendar years 2016 through 2018.

OPUC Data Request 676

Wages, Salaries and Incentives
Referring to the Company's response in DRs 92,123, 178 & 272 please provide the amount of Officer Incentives and Other Executives incentives (Officers) capitalized in Plant Costs. This request is ongoing.

Officers' Incentives Capitalized in Plant			
Calendar Year	PAC	Allocated to Oregon Jurisdiction	Allocated to Oregon Jurisdiction and included in rate base
2017	$	$	$
2018			
2019			
2020			
Total			

Response to OPUC Data Request 676

Please refer to the table below for the amount of Annual Incentive Plan (AIP) awards for PacifiCorp's Named Executive Officers (NEOs), capitalized to Account 107, Construction Work In Progress (CWIP). The Company cannot specifically state the amount of NEO incentive in CWIP that was placed in service to Electric Plant for any year, or the amount allocated to Oregon. The amounts below are estimates of the NEO incentives in Electric Plant allocated to Oregon. The Company is unable to estimate the depreciated value of these amounts and therefore cannot provide the net amount included in rate base allocated to Oregon.

Calendar Year	PacifiCorp NEO, Capitalized AIP	Oregon's Allocated share[1]
2017	$410,100	$111,165
2018	$295,922	$80,898
2019	$397,773	$109,557
2020	Not available[2]	Not available[2]
Total	$1,103,795	$301,620

Notes:

1. Oregon's Allocated share is extrapolated using an unadjusted gross electric plant in service percentage calculated as: Oregon's gross electric plant in service balance divided by Total Company gross electric plant in service balance. Gross electric plant in service balances are sourced from the Company's annual results of operations filing.
2. 2020 incentives will not be available until December 2020 when they are paid. The 2020 Oregon allocation will not be available until the Company's 2020 Results of Operations is filed with the Commission in April 2021.

OPUC Data Request 696

Union Wages, Wages and Salaries
Please provide staff with average Oregon union increases per year for calendar years 2017, 2018, 2019, 2020.

Response to OPUC Data Request 696

Please refer to Attachment OPUC 696 for the average union percentage increase and timing for each of PacifiCorp's unions. All unions, not just Oregon unions, are included in the response as labor costs are allocated.

CASE: UE 374
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2502

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Docket No. UE 374

APPENDIX A: ECONOMIC FORECAST DETAIL

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Docket No. UE 374

Table A.1 – Employment Forecast Tracking

Total Nonfarm Employment, 1st quarter 2020
(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate		Forecast		Forecast Error		Y/Y Change
	level	% ch	level	% ch	level	%	% ch
Total Nonfarm	1,960.1	0.6	1,959.7	1.9	0.4	0.0	1.4
Total Private	1,657.6	(0.1)	1,660.3	1.9	(2.7)	(0.2)	1.3
Mining and Logging	6.7	(6.9)	7.0	12.0	(0.3)	(3.8)	(4.4)
Construction	112.5	5.2	110.2	1.6	2.3	2.1	3.8
Manufacturing	196.4	(1.8)	198.7	0.7	(2.3)	(1.2)	(1.2)
Durable Goods	135.7	(1.2)	138.0	2.6	(2.3)	(1.7)	(1.6)
Wood Product	22.7	(4.0)	23.6	5.8	(0.9)	(3.9)	(3.8)
Metals and Machinery	39.9	(2.5)	40.2	0.9	(0.4)	(1.0)	(1.5)
Computer and Electronic Product	38.6	0.7	39.0	4.2	(0.4)	(0.9)	(0.0)
Transportation Equipment	12.2	(2.6)	12.4	(6.2)	(0.2)	(1.7)	(3.2)
Other Durable Goods	22.3	1.4	22.8	4.9	(0.4)	(2.0)	(1.3)
Nondurable Goods	60.7	(3.2)	60.7	(3.5)	(0.0)	(0.0)	(0.2)
Food	28.9	(8.5)	29.1	(7.3)	(0.2)	(0.7)	(4.1)
Other Nondurable Goods	31.8	1.9	31.6	0.2	0.2	0.6	3.6
Trade, Transportation & Utilities	360.3	0.8	359.1	0.4	1.2	0.3	1.3
Retail Trade	208.6	(0.5)	209.7	0.2	(1.1)	(0.5)	(0.9)
Wholesale Trade	77.0	1.5	77.0	1.3	0.0	0.0	0.7
Transportation, Warehousing & Utilities	74.7	3.5	72.4	0.1	2.3	3.2	8.5
Information	35.2	(5.8)	35.5	2.0	(0.3)	(0.8)	1.8
Financial Activities	104.9	2.7	104.1	1.5	0.8	0.7	1.9
Professional & Business Services	257.2	(1.3)	257.2	3.1	(0.1)	(0.0)	1.9
Educational & Health Services	304.3	(1.3)	306.2	2.9	(1.9)	(0.6)	2.1
Educational Services	36.5	(5.3)	36.3	(7.2)	0.3	0.7	(0.1)
Health Services	267.8	(0.8)	269.9	4.3	(2.2)	(0.8)	2.4
Leisure and Hospitality	214.8	(0.1)	217.8	3.4	(3.0)	(1.4)	0.7
Other Services	65.3	2.2	64.4	(0.9)	0.9	1.4	0.9
Government	302.5	4.2	299.4	2.0	3.1	1.0	1.6
Federal	28.5	1.2	27.9	(6.3)	0.6	2.1	0.9
State	42.2	23.6	39.6	(2.4)	2.6	6.6	2.7
State Education	0.9	(12.7)	0.8	(7.3)	0.1	11.9	13.6
Local	231.7	1.4	231.8	3.9	(0.1)	(0.1)	1.5
Local Education	135.8	1.6	132.3	(2.2)	3.5	2.7	2.3

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Table A.2 – Short-Term Oregon Economic Summary

Oregon Forecast Summary

	Quarterly					Annual					
	2020:1	2020:2	2020:3	2020:4	2021:1	2019	2020	2021	2022	2023	2024
Personal Income ($ billions)											
Nominal Personal Income	229.4	224.4	226.2	222.4	222.9	223.3	225.6	226.0	236.6	249.2	262.8
% change	6.2	(8.5)	3.3	(6.6)	0.9	4.8	1.0	0.2	4.7	5.3	5.4
Real Personal Income (base year=2012)	207.2	203.9	204.6	200.2	199.9	203.6	204.0	201.4	206.8	213.0	219.9
% change	4.6	(6.3)	1.4	(8.3)	(0.7)	3.3	0.2	(1.3)	2.6	3.0	3.2
Nominal Wages and Salaries	115.8	96.6	99.6	102.2	103.3	112.0	103.6	104.6	112.3	122.5	132.5
% change	9.9	(51.6)	12.9	10.9	4.3	4.6	(7.5)	1.1	7.3	9.1	8.2
Other Indicators											
Per Capita Income ($1,000)	53.9	52.6	53.0	52.0	52.1	52.7	52.9	52.7	54.7	57.2	59.8
% change	5.6	(9.1)	2.7	(7.2)	0.5	3.8	0.4	(0.4)	3.9	4.4	4.6
Average Wage rate ($1,000)	58.3	61.5	59.7	59.3	59.4	57.1	59.7	59.6	61.4	64.0	66.8
% change	7.4	23.9	(11.2)	(2.9)	0.7	3.0	4.5	(0.1)	3.0	4.2	4.4
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.24	4.27	4.29	4.32	4.36	4.40
% change	0.6	0.7	0.6	0.6	0.4	1.0	0.7	0.6	0.8	0.8	0.8
Housing Starts (Thousands)	18.9	15.3	14.9	15.7	16.2	20.7	16.2	16.7	18.9	21.4	21.9
% change	(30.2)	(57.1)	(10.3)	21.6	13.3	5.9	(21.7)	3.0	13.3	13.1	2.3
Unemployment Rate	3.9	22.7	18.5	16.0	15.3	4.1	15.3	14.7	11.4	7.6	4.6
Point Change	0.0	18.8	(4.2)	(2.5)	(0.7)	(0.0)	11.2	(0.6)	(3.3)	(3.8)	(3.0)
Employment (Thousands)											
Total Nonfarm	1,960.1	1,553.6	1,650.5	1,707.1	1,722.4	1,942.9	1,717.8	1,736.9	1,810.7	1,898.1	1,969.2
% change	0.6	(60.5)	27.4	14.4	3.6	1.6	(11.6)	1.1	4.2	4.8	3.7
Private Nonfarm	1,657.6	1,250.2	1,350.2	1,410.4	1,427.8	1,644.0	1,417.1	1,444.0	1,514.9	1,600.0	1,666.4
% change	(0.1)	(67.6)	36.0	19.1	5.0	1.6	(13.8)	1.9	4.9	5.6	4.1
Construction	112.5	86.6	85.5	86.1	88.6	109.4	92.7	91.5	96.4	100.9	104.4
% change	5.2	(64.9)	(5.1)	3.1	11.9	3.7	(15.3)	(1.3)	5.4	4.6	3.5
Manufacturing	196.4	161.1	157.4	153.4	153.2	198.0	167.1	157.2	168.9	178.1	183.3
% change	(1.8)	(54.7)	(8.9)	(9.8)	(0.6)	1.4	(15.6)	(5.9)	7.4	5.5	2.9
Durable Manufacturing	135.7	109.2	106.2	103.0	102.5	137.0	113.5	106.0	115.2	121.9	125.9
% change	(1.2)	(58.0)	(10.7)	(11.5)	(1.7)	1.1	(17.1)	(6.6)	8.7	5.8	3.2
Wood Product Manufacturing	22.7	15.3	15.2	14.6	14.7	23.2	17.0	15.0	17.3	20.0	21.8
% change	(4.0)	(79.0)	(4.7)	(12.8)	0.8	(1.2)	(27.0)	(11.2)	15.2	15.3	8.9
High Tech Manufacturing	38.6	37.0	37.0	36.9	36.3	38.6	37.4	36.8	37.4	37.5	37.4
% change	0.7	(15.7)	(0.2)	(1.2)	(6.0)	1.8	(3.2)	(1.5)	1.6	0.2	(0.3)
Transportation Equipment	12.2	9.8	9.5	9.2	9.3	12.6	10.2	9.6	10.3	10.8	11.3
% change	(2.6)	(58.2)	(11.5)	(11.6)	0.8	3.6	(18.9)	(6.0)	7.4	4.5	5.1
Nondurable Manufacturing	60.7	51.9	51.3	50.4	50.6	61.0	53.6	51.2	53.7	56.2	57.4
% change	(3.2)	(46.4)	(5.1)	(6.2)	1.5	2.2	(12.2)	(4.4)	4.7	4.7	2.2
Private nonmanufacturing	1,461.3	1,089.1	1,192.8	1,257.0	1,274.6	1,446.1	1,250.0	1,286.8	1,346.0	1,421.9	1,483.1
% change	0.2	(69.1)	43.9	23.3	5.7	1.6	(13.6)	2.9	4.6	5.6	4.3
Retail Trade	208.6	158.0	174.1	183.9	184.5	209.8	181.2	185.2	188.3	191.5	195.2
% change	(0.5)	(67.1)	47.5	24.7	1.2	(0.8)	(13.6)	2.3	1.6	1.7	2.0
Wholesale Trade	77.0	66.0	63.0	65.5	66.8	76.5	67.9	67.2	69.3	72.7	76.3
% change	1.5	(45.9)	(17.0)	16.7	8.3	1.2	(11.3)	(1.0)	3.1	4.9	5.0
Information	35.2	31.0	30.7	31.2	31.8	35.1	32.0	32.1	32.9	33.2	33.4
% change	(5.8)	(39.8)	(3.8)	7.0	7.8	2.1	(8.6)	0.2	2.3	0.9	0.8
Professional and Business Services	257.2	222.3	216.5	220.3	223.3	254.3	229.1	225.3	240.7	266.2	287.1
% change	(1.3)	(44.2)	(10.1)	7.2	5.6	1.8	(9.9)	(1.6)	6.8	10.6	7.9
Health Services	267.8	201.9	232.5	247.5	250.8	264.9	237.4	253.7	263.4	273.8	285.1
% change	(0.8)	(67.7)	75.8	28.4	5.4	2.3	(10.4)	6.9	3.8	3.9	4.1
Leisure and Hospitality	214.8	86.7	139.0	160.8	164.9	213.8	150.3	166.9	184.9	207.6	222.7
% change	(0.1)	(97.3)	560.4	79.0	10.7	1.1	(29.7)	11.0	10.8	12.3	7.3
Government	302.5	303.4	300.3	296.6	294.6	298.9	300.7	292.9	295.9	298.1	302.8
% change	4.2	1.2	(4.0)	(4.8)	(2.7)	1.4	0.6	(2.6)	1.0	0.8	1.6

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Table A.3 – Oregon Economic Forecast Change

Oregon Forecast Change (Current vs. Last)

	Quarterly					Annual					
	2020:1	2020:2	2020:3	2020:4	2021:1	2019	2020	2021	2022	2023	2024
Personal Income ($ billions)											
Nominal Personal Income	229.4	224.4	226.2	222.4	222.9	223.3	225.6	226.0	236.6	249.2	262.8
% change	(0.2)	(3.5)	(3.9)	(6.6)	(7.5)	(0.2)	(3.6)	(7.9)	(8.1)	(7.7)	(7.2)
Real Personal Income (base year=2012)	207.2	203.9	204.6	200.2	199.9	203.6	204.0	201.4	206.8	213.0	219.9
% change	(0.1)	(2.4)	(2.9)	(5.7)	(6.7)	(0.2)	(2.8)	(6.9)	(6.9)	(6.4)	(5.9)
Nominal Wages and Salaries	115.8	96.6	99.6	102.2	103.3	112.0	103.6	104.6	112.3	122.5	132.5
% change	(0.4)	(18.1)	(16.7)	(15.6)	(15.8)	(0.4)	(12.8)	(16.4)	(14.8)	(11.4)	(8.7)
Other Indicators											
Per Capita Income ($1,000)	53.9	52.6	53.0	52.0	52.1	52.7	52.9	52.7	54.7	57.2	59.8
% change	(0.1)	(3.3)	(3.6)	(6.2)	(7.1)	(0.2)	(3.3)	(7.4)	(7.5)	(6.9)	(6.4)
Average Wage rate ($1,000)	58.3	61.5	59.7	59.3	59.4	57.1	59.7	59.6	61.4	64.0	66.8
% change	(0.8)	3.6	(0.4)	(2.1)	(2.9)	(0.4)	0.0	(3.9)	(5.1)	(5.1)	(5.0)
Population (Millions)	4.26	4.26	4.27	4.3	4.3	4.24	4.27	4.29	4.32	4.36	4.40
% change	(0.2)	(0.2)	(0.3)	(0.4)	(0.5)	0.0	(0.3)	(0.6)	(0.7)	(0.8)	(0.8)
Housing Starts (Thousands)	18.9	15.3	14.9	15.7	16.2	20.7	16.2	16.7	18.9	21.4	21.9
% change	(14.1)	(31.5)	(34.0)	(31.2)	(30.5)	(0.1)	(27.8)	(28.4)	(19.9)	(8.5)	(7.5)
Unemployment Rate	3.9	22.7	18.5	16.0	15.3	4.1	15.3	14.7	11.4	7.6	4.6
Point Change	0.0	18.9	14.7	12.2	11.5	0.0	11.4	10.8	7.4	3.4	0.2
Employment (Thousands)											
Total Nonfarm	1,960.1	1,553.6	1,650.5	1,707.1	1,722.4	1,942.9	1,717.8	1,736.9	1,810.7	1,898.1	1,969.2
% change	0.0	(21.2)	(16.5)	(13.9)	(13.5)	0.1	(12.9)	(13.1)	(10.4)	(6.8)	(3.9)
Private Nonfarm	1,657.6	1,250.2	1,350.2	1,410.4	1,427.8	1,644.0	1,417.1	1,444.0	1,514.9	1,600.0	1,666.4
% change	(0.2)	(25.0)	(19.4)	(16.1)	(15.4)	0.1	(15.2)	(14.8)	(11.5)	(7.3)	(4.0)
Construction	112.5	86.6	85.5	86.1	88.6	109.4	92.7	91.5	96.4	100.9	104.4
% change	2.1	(21.7)	(22.8)	(22.4)	(20.6)	0.3	(16.2)	(18.4)	(14.2)	(10.9)	(8.3)
Manufacturing	196.4	161.1	157.4	153.4	153.2	198.0	167.1	157.2	168.9	178.1	183.3
% change	(1.2)	(18.9)	(20.7)	(22.6)	(22.7)	(0.1)	(15.9)	(20.5)	(14.6)	(9.9)	(7.3)
Durable Manufacturing	135.7	109.2	106.2	103.0	102.5	137.0	113.5	106.0	115.2	121.9	125.9
% change	(1.7)	(20.9)	(23.0)	(25.2)	(25.5)	(0.2)	(17.7)	(22.6)	(15.6)	(10.5)	(7.6)
Wood Product Manufacturing	22.7	15.3	15.2	14.6	14.7	23.2	17.0	15.0	17.3	20.0	21.8
% change	(3.9)	(35.1)	(35.6)	(37.6)	(37.6)	(0.3)	(28.0)	(35.5)	(25.3)	(14.2)	(7.9)
High Tech Manufacturing	38.6	37.0	37.0	36.9	36.3	38.6	37.4	36.8	37.4	37.5	37.4
% change	(0.9)	(5.1)	(4.8)	(5.2)	(6.4)	0.0	(4.0)	(4.9)	(3.8)	(3.4)	(2.9)
Transportation Equipment	12.2	9.8	9.5	9.2	9.3	12.6	10.2	9.6	10.3	10.8	11.3
% change	(1.7)	(21.4)	(24.1)	(26.7)	(26.6)	(0.5)	(18.5)	(23.8)	(18.1)	(14.5)	(10.5)
Nondurable Manufacturing	60.7	51.9	51.3	50.4	50.6	61.0	53.6	51.2	53.7	56.2	57.4
% change	(0.0)	(14.4)	(15.4)	(16.8)	(16.6)	(0.1)	(11.7)	(15.8)	(12.4)	(8.8)	(6.8)
Private nonmanufacturing	1,461.3	1,089.1	1,192.8	1,257.0	1,274.6	1,446.1	1,250.0	1,286.8	1,346.0	1,421.9	1,483.1
% change	(0.0)	(25.8)	(19.2)	(15.2)	(14.4)	0.1	(15.1)	(14.0)	(11.1)	(6.9)	(3.6)
Retail Trade	208.6	158.0	174.1	183.9	184.5	209.8	181.2	185.2	188.3	191.5	195.2
% change	(0.5)	(24.7)	(17.1)	(12.4)	(12.1)	(0.1)	(13.7)	(11.8)	(10.5)	(9.1)	(7.5)
Wholesale Trade	77.0	66.0	63.0	65.5	66.8	76.5	67.9	67.2	69.3	72.7	76.3
% change	0.0	(14.3)	(18.4)	(15.3)	(13.7)	0.2	(12.0)	(13.3)	(10.9)	(6.6)	(2.0)
Information	35.2	31.0	30.7	31.2	31.8	35.1	32.0	32.1	32.9	33.2	33.4
% change	(0.8)	(12.4)	(13.1)	(11.7)	(10.0)	0.4	(9.5)	(9.2)	(7.1)	(6.2)	(5.3)
Professional and Business Services	257.2	222.3	216.5	220.3	223.3	254.3	229.1	225.3	240.7	266.2	287.1
% change	(0.0)	(14.2)	(17.8)	(17.3)	(17.3)	0.2	(12.4)	(17.9)	(15.4)	(7.9)	(2.2)
Health Services	267.8	201.9	232.5	247.5	250.8	264.9	237.4	253.7	263.4	273.8	285.1
% change	(0.8)	(25.9)	(15.1)	(10.0)	(9.2)	0.1	(13.0)	(8.7)	(6.8)	(4.8)	(2.2)
Leisure and Hospitality	214.8	86.7	139.0	160.8	164.9	213.8	150.3	166.9	184.9	207.6	222.7
% change	(1.4)	(60.4)	(37.0)	(27.6)	(25.9)	(0.1)	(31.6)	(25.2)	(17.6)	(8.5)	(2.4)
Government	302.5	303.4	300.3	296.6	294.6	298.9	300.7	292.9	295.9	298.1	302.8
% change	1.0	(0.1)	(0.6)	(1.9)	(2.9)	0.2	(0.4)	(3.9)	(3.9)	(4.0)	(3.3)

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Table A.4 – Annual Economic Forecast

Jun 2020 - Personal Income

(Billions of Current Dollars)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Personal Income*												
Oregon	213.1	223.3	225.6	226.0	236.6	249.2	262.8	277.0	291.4	306.3	322.0	338.5
% Ch	6.2	4.8	1.0	0.2	4.7	5.3	5.4	5.4	5.2	5.1	5.1	5.1
U.S.	17,819.2	18,602.3	18,913.4	19,494.0	20,405.7	21,176.3	21,991.6	22,972.5	24,043.2	25,176.9	26,395.3	27,676.2
% Ch	5.6	4.4	1.7	3.1	4.7	3.8	3.9	4.5	4.7	4.7	4.8	4.9
Wage and Salary												
Oregon	107.0	112.0	103.6	104.6	112.3	122.5	132.5	140.6	148.3	156.2	164.3	172.6
% Ch	5.7	4.6	(7.5)	1.1	7.3	9.1	8.2	6.1	5.5	5.3	5.2	5.1
U.S.	8,888.5	9,297.8	8,996.6	9,321.1	10,188.8	10,718.5	11,121.1	11,576.5	12,097.6	12,654.1	13,245.4	13,869.4
% Ch	5.0	4.6	(3.2)	3.6	9.3	5.2	3.8	4.1	4.5	4.6	4.7	4.7
Other Labor Income												
Oregon	25.6	26.7	24.4	24.8	27.3	29.6	31.7	33.6	35.4	37.3	39.2	41.2
% Ch	4.4	4.2	(8.6)	1.7	10.0	8.3	7.1	6.1	5.5	5.3	5.1	5.0
U.S.	1,417.2	1,473.2	1,426.8	1,478.1	1,615.8	1,699.8	1,763.7	1,835.9	1,918.5	2,006.7	2,100.5	2,199.4
% Ch	5.5	4.0	(3.1)	3.6	9.3	5.2	3.8	4.1	4.5	4.6	4.7	4.7
Nonfarm Proprietor's Income												
Oregon	18.1	18.8	17.4	19.0	19.8	20.4	21.1	21.8	22.5	23.2	23.9	24.7
% Ch	4.4	4.1	(7.7)	9.0	4.3	3.2	3.2	3.2	3.2	3.2	3.2	3.2
U.S.	1,561.6	1,626.3	1,544.9	1,811.2	1,696.2	1,694.4	1,747.5	1,798.8	1,845.0	1,892.1	1,942.8	1,988.8
% Ch	5.5	4.1	(5.0)	17.2	(6.3)	(0.1)	3.1	2.9	2.6	2.6	2.7	2.4
Dividend, Interest and Rent												
Oregon	45.8	47.0	47.3	48.1	49.0	49.4	50.6	52.7	55.3	58.1	61.5	65.3
% Ch	8.3	2.6	0.6	1.7	1.9	0.8	2.5	4.3	4.8	5.2	5.8	6.2
U.S.	3,686.9	3,770.8	3,828.2	3,923.4	4,021.0	4,062.5	4,191.9	4,413.3	4,651.8	4,912.6	5,216.8	5,554.9
% Ch	8.4	2.3	1.5	2.5	2.5	1.0	3.2	5.3	5.4	5.6	6.2	6.5
Transfer Payments												
Oregon	40.0	43.2	55.9	52.3	52.2	53.2	54.9	57.9	60.9	64.0	67.2	70.3
% Ch	5.9	8.0	29.3	(6.4)	(0.1)	2.0	3.1	5.4	5.3	5.1	4.9	4.7
U.S.	2,918.3	3,117.3	3,777.8	3,636.0	3,590.3	3,742.3	3,950.7	4,165.4	4,381.1	4,601.0	4,823.3	5,043.2
% Ch	4.1	6.8	21.2	(3.8)	(1.3)	4.2	5.6	5.4	5.2	5.0	4.8	4.6
Contributions for Social Security												
Oregon	18.5	19.3	18.3	18.2	19.4	21.2	22.8	24.2	25.4	26.8	28.1	29.6
% Ch	3.5	4.2	(5.2)	(0.5)	6.8	8.9	7.9	5.8	5.2	5.3	5.1	5.0
U.S.	733.7	769.6	742.6	765.9	834.7	876.2	907.8	943.8	985.5	1,030.2	1,077.9	1,128.3
% Ch	5.7	4.9	(3.5)	3.1	9.0	5.0	3.6	4.0	4.4	4.5	4.6	4.7
Residence Adjustment												
Oregon	(4.9)	(5.1)	(4.7)	(4.6)	(4.8)	(5.1)	(5.4)	(5.7)	(5.9)	(6.1)	(6.3)	(6.5)
% Ch	4.0	4.0	(8.7)	(1.7)	4.0	6.9	6.5	4.5	3.5	3.9	3.5	3.1
Farm Proprietor's Income												
Oregon	(0.1)	(0.0)	0.0	0.0	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.3
% Ch	(429.7)	(31.1)	(181.6)	(53.9)	1,350.3	27.2	(22.1)	(1.5)	13.6	6.0	(1.0)	(0.1)
Per Capita Income (Thousands of $)												
Oregon	50.8	52.7	52.9	52.7	54.7	57.2	59.8	62.5	65.2	68.0	70.9	73.9
% Ch	4.9	3.8	0.4	(0.4)	3.9	4.4	4.6	4.6	4.3	4.3	4.3	4.3
U.S.	54.4	56.4	56.9	58.2	60.5	62.4	64.4	66.8	69.5	72.3	75.3	78.5
% Ch	4.9	3.7	1.0	2.4	4.0	3.1	3.2	3.8	4.0	4.1	4.2	4.2

* Personal Income includes all classes of income minus Contributions for Social Security

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Jun 2020 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Nonfarm												
Oregon	1,912.8	1,942.9	1,717.8	1,736.9	1,810.7	1,898.1	1,969.2	2,004.1	2,028.3	2,049.8	2,069.5	2,088.1
% Ch	2.0	1.6	(11.6)	1.1	4.2	4.8	3.7	1.8	1.2	1.1	1.0	0.9
U.S.	148.9	150.9	144.1	142.7	150.9	154.1	154.5	154.7	155.3	156.1	157.0	157.9
% Ch	1.6	1.4	(4.5)	(0.9)	5.7	2.1	0.3	0.1	0.4	0.5	0.6	0.6
Private Nonfarm												
Oregon	1,618.0	1,644.0	1,417.1	1,444.0	1,514.9	1,600.0	1,666.4	1,696.2	1,715.9	1,733.2	1,748.5	1,763.7
% Ch	3.3	1.6	(13.8)	1.9	4.9	5.6	4.1	1.8	1.2	1.0	0.9	0.9
U.S.	126.4	128.3	121.2	119.8	127.9	130.9	131.1	131.1	131.6	132.2	133.0	133.8
% Ch	1.8	1.5	(5.6)	(1.1)	6.7	2.4	0.2	(0.0)	0.3	0.5	0.6	0.6
Mining and Logging												
Oregon	7.2	6.9	5.2	4.9	5.7	6.1	6.3	6.5	6.8	7.0	7.1	7.2
% Ch	3.3	(4.0)	(25.0)	(5.1)	14.8	7.3	3.6	3.6	3.7	2.9	1.9	1.1
U.S.	0.7	0.7	0.6	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6
% Ch	7.6	1.2	(20.5)	(33.9)	10.0	9.2	3.4	3.7	3.7	3.2	2.0	1.5
Construction												
Oregon	105.4	109.4	92.7	91.5	96.4	100.9	104.4	106.6	108.3	110.0	111.5	113.1
% Ch	7.8	3.7	(15.3)	(1.3)	5.4	4.6	3.5	2.1	1.6	1.5	1.4	1.4
U.S.	7.3	7.5	7.2	6.8	7.1	7.4	7.6	7.8	7.9	8.0	8.1	8.3
% Ch	4.6	2.9	(3.8)	(6.2)	4.9	4.9	2.4	1.9	1.5	1.3	1.7	2.2
Manufacturing												
Oregon	195.2	198.0	167.1	157.2	168.9	178.1	183.3	186.5	188.2	189.6	190.4	190.5
% Ch	2.7	1.4	(15.6)	(5.9)	7.4	5.5	2.9	1.7	0.9	0.7	0.4	0.0
U.S.	12.7	12.8	12.2	11.2	11.5	11.9	12.0	12.0	12.0	12.0	11.8	11.7
% Ch	2.0	1.2	(4.9)	(7.9)	2.3	3.0	1.3	(0.1)	0.2	(0.5)	(1.1)	(1.1)
Durable Manufacturing												
Oregon	135.5	137.0	113.5	106.0	115.2	121.9	125.9	128.2	129.3	130.0	130.2	130.0
% Ch	2.9	1.1	(17.1)	(6.6)	8.7	5.8	3.2	1.8	0.9	0.5	0.2	(0.1)
U.S.	7.9	8.1	7.6	6.8	7.0	7.3	7.4	7.5	7.5	7.5	7.4	7.3
% Ch	2.7	1.4	(6.1)	(10.4)	2.7	4.1	2.3	0.6	0.8	(0.3)	(1.3)	(1.4)
Wood Products												
Oregon	23.5	23.2	17.0	15.0	17.3	20.0	21.8	22.7	22.9	23.0	23.1	23.1
% Ch	2.5	(1.2)	(27.0)	(11.2)	15.2	15.3	8.9	4.3	1.0	0.3	0.3	0.3
U.S.	0.4	0.4	0.4	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
% Ch	2.3	0.7	(6.6)	(25.2)	26.2	9.7	5.8	4.3	4.0	1.1	0.0	0.6
Metal and Machinery												
Oregon	39.3	40.2	31.4	29.1	33.3	35.1	36.1	36.9	37.5	37.9	38.0	37.9
% Ch	5.3	2.3	(22.0)	(7.4)	14.4	5.6	2.6	2.2	1.7	1.0	0.2	(0.1)
U.S.	3.0	3.0	2.8	2.5	2.6	2.8	2.9	2.9	2.9	2.9	2.9	2.8
% Ch	3.2	1.2	(7.1)	(9.0)	2.9	5.7	3.3	1.1	1.0	(0.4)	(1.7)	(1.7)
Computer and Electronic Products												
Oregon	37.9	38.6	37.4	36.8	37.4	37.5	37.4	37.1	36.9	36.7	36.4	36.2
% Ch	2.9	1.8	(3.2)	(1.5)	1.6	0.2	(0.3)	(0.7)	(0.5)	(0.6)	(0.7)	(0.5)
U.S.	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
% Ch	1.5	2.5	(3.7)	(3.1)	1.2	0.1	0.9	0.5	(0.2)	(0.6)	(1.3)	(1.3)
Transportation Equipment												
Oregon	12.1	12.6	10.2	9.6	10.3	10.8	11.3	11.6	11.8	11.8	11.8	11.7
% Ch	2.2	3.6	(18.9)	(6.0)	7.4	4.5	5.1	2.4	1.7	0.5	0.0	(1.0)
U.S.	1.7	1.7	1.6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
% Ch	3.6	1.9	(8.3)	(14.8)	(0.0)	4.9	1.0	(0.6)	0.3	(0.4)	(1.3)	(2.2)
Other Durables												
Oregon	22.6	22.3	17.6	15.5	16.9	18.5	19.4	19.9	20.2	20.6	20.9	21.0
% Ch	(0.0)	(1.1)	(21.3)	(12.0)	9.2	9.7	4.4	3.0	1.4	1.9	1.5	0.4
U.S.	2.2	2.2	2.1	1.9	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1
% Ch	1.8	0.8	(4.5)	(12.4)	5.2	3.7	2.5	0.8	1.4	0.1	(0.7)	(0.6)
Nondurable Manufacturing												
Oregon	59.7	61.0	53.6	51.2	53.7	56.2	57.4	58.3	58.9	59.6	60.2	60.4
% Ch	2.2	2.2	(12.2)	(4.4)	4.7	4.7	2.2	1.6	0.9	1.2	1.0	0.4
U.S.	4.7	4.8	4.6	4.5	4.5	4.6	4.6	4.5	4.5	4.4	4.4	4.4
% Ch	0.9	0.8	(2.8)	(3.8)	1.8	1.2	(0.3)	(1.3)	(0.9)	(0.9)	(0.9)	(0.7)
Food Manufacturing												
Oregon	29.9	29.8	28.5	29.2	29.6	29.8	29.8	29.9	30.0	30.2	30.3	30.5
% Ch	0.3	(0.3)	(4.3)	2.2	1.4	0.7	0.3	0.2	0.5	0.6	0.4	0.5
U.S.	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8
% Ch	1.4	1.3	1.5	(0.7)	3.6	2.7	1.3	(0.0)	0.4	0.2	0.0	0.2
Other Nondurable												
Oregon	29.8	31.2	25.1	22.1	24.1	26.4	27.6	28.4	28.8	29.4	29.8	29.9
% Ch	4.1	4.8	(19.7)	(12.0)	9.2	9.7	4.4	3.0	1.4	1.9	1.5	0.4
U.S.	3.1	3.1	3.0	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.6	2.6
% Ch	0.7	0.5	(5.1)	(5.5)	0.7	0.3	(1.3)	(2.1)	(1.8)	(1.6)	(1.5)	(1.3)
Trade, Transportation, and Utilities												
Oregon	352.8	357.0	315.8	319.5	325.6	334.0	342.5	344.4	345.2	346.0	346.8	347.5
% Ch	1.1	1.2	(11.5)	1.2	1.9	2.6	2.5	0.6	0.2	0.2	0.2	0.2
U.S.	27.6	27.7	25.4	25.0	27.0	26.7	27.0	26.8	26.7	26.6	26.5	26.4
% Ch	0.8	0.4	(8.5)	(1.6)	8.1	(1.2)	1.3	(0.6)	(0.7)	(0.3)	(0.4)	(0.4)

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Jun 2020 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Retail Trade												
Oregon	211.5	209.8	181.2	185.2	188.3	191.5	195.2	195.8	196.2	196.9	197.3	197.8
% Ch	0.3	(0.8)	(13.6)	2.3	1.6	1.7	2.0	0.3	0.2	0.3	0.2	0.2
U.S.	15.8	15.6	14.1	14.5	15.9	15.3	15.8	15.6	15.5	15.4	15.3	15.3
% Ch	(0.4)	(0.9)	(9.9)	2.7	9.9	(3.8)	3.2	(0.9)	(1.2)	(0.5)	(0.3)	(0.3)
Wholesale Trade												
Oregon	75.6	76.5	67.9	67.2	69.3	72.7	76.3	77.5	77.7	77.8	78.0	78.1
% Ch	0.9	1.2	(11.3)	(1.0)	3.1	4.9	5.0	1.6	0.2	0.1	0.2	0.1
U.S.	5.8	5.9	5.4	4.9	5.2	5.4	5.3	5.3	5.3	5.3	5.3	5.3
% Ch	0.5	1.1	(9.3)	(8.3)	5.6	3.6	(0.7)	(0.1)	(0.1)	0.1	(0.6)	(0.8)
Transportation and Warehousing, and Utilities												
Oregon	65.7	70.7	66.7	67.1	68.0	69.8	70.9	71.1	71.3	71.3	71.5	71.6
% Ch	4.0	7.6	(5.6)	0.5	1.4	2.6	1.6	0.3	0.2	0.1	0.2	0.1
U.S.	6.0	6.2	5.9	5.6	5.9	6.0	5.9	5.9	5.9	5.9	5.8	5.8
% Ch	4.3	3.1	(4.2)	(5.6)	5.7	1.7	(2.0)	(0.3)	0.1	(0.3)	(0.5)	(0.5)
Information												
Oregon	34.3	35.1	32.0	32.1	32.9	33.2	33.4	33.7	33.9	34.2	34.4	34.7
% Ch	0.3	2.1	(8.6)	0.2	2.3	0.9	0.8	0.7	0.8	0.8	0.8	0.7
U.S.	2.8	2.9	2.8	2.7	2.7	2.7	2.8	2.7	2.7	2.7	2.7	2.7
% Ch	0.9	0.8	(1.4)	(4.6)	1.5	(0.1)	1.3	(1.3)	(0.6)	(1.5)	(0.1)	0.4
Financial Activities												
Oregon	102.2	103.4	99.0	99.3	100.4	101.5	101.9	102.3	102.5	102.7	102.8	102.9
% Ch	2.2	1.1	(4.2)	0.3	1.0	1.1	0.4	0.4	0.2	0.1	0.1	0.1
U.S.	8.6	8.7	8.3	7.6	8.2	8.2	8.0	8.0	8.0	7.9	7.9	7.9
% Ch	1.7	1.8	(4.8)	(9.0)	7.8	0.5	(2.0)	(0.4)	(0.6)	(0.5)	0.1	0.2
Professional and Business Services												
Oregon	249.7	254.3	229.1	225.3	240.7	266.2	287.1	298.8	307.0	313.6	319.3	325.2
% Ch	2.1	1.8	(9.9)	(1.6)	6.8	10.6	7.9	4.1	2.8	2.1	1.8	1.9
U.S.	21.0	21.3	19.8	19.1	23.0	24.0	23.7	24.0	24.5	24.9	25.3	25.7
% Ch	2.2	1.7	(7.1)	(3.3)	20.3	4.1	(1.1)	1.1	2.1	1.8	1.7	1.4
Education and Health Services												
Oregon	295.4	301.5	269.6	289.0	298.7	309.2	320.6	327.2	331.0	334.3	337.4	340.9
% Ch	8.2	2.1	(10.6)	7.2	3.4	3.5	3.7	2.1	1.2	1.0	1.0	1.0
U.S.	23.6	24.2	24.0	24.0	25.6	25.9	25.5	25.5	25.4	25.5	25.7	25.9
% Ch	1.9	2.3	(0.5)	(0.3)	7.0	0.8	(1.4)	(0.2)	(0.1)	0.4	0.8	0.9
Educational Services												
Oregon	36.5	36.6	32.2	35.2	35.3	35.4	35.5	35.6	35.7	35.7	35.8	35.8
% Ch	1.3	0.3	(12.2)	9.5	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.1
U.S.	3.7	3.8	3.6	3.9	4.1	4.0	3.8	3.6	3.5	3.5	3.5	3.4
% Ch	1.2	1.3	(5.0)	8.3	6.1	(3.1)	(5.5)	(3.5)	(2.3)	(1.5)	(1.1)	(1.0)
Health Care and Social Assistance												
Oregon	258.9	264.9	237.4	253.7	263.4	273.8	285.1	291.6	295.4	298.5	301.7	305.0
% Ch	9.3	2.3	(10.4)	6.9	3.8	3.9	4.1	2.3	1.3	1.1	1.0	1.1
U.S.	19.9	20.4	20.5	20.1	21.5	21.9	21.7	21.8	21.9	22.0	22.3	22.5
% Ch	2.1	2.5	0.3	(1.9)	7.2	1.6	(0.6)	0.4	0.2	0.7	1.1	1.2
Leisure and Hospitality												
Oregon	211.4	213.8	150.3	166.9	184.9	207.6	222.7	225.8	228.3	230.8	233.1	235.7
% Ch	2.4	1.1	(29.7)	11.0	10.8	12.3	7.3	1.4	1.1	1.1	1.0	1.1
U.S.	16.3	16.6	15.2	17.5	16.3	17.8	18.3	18.2	18.3	18.5	18.7	18.9
% Ch	1.5	1.7	(8.5)	15.4	(6.6)	8.9	2.7	(0.4)	0.5	1.3	1.1	1.0
Other Services												
Oregon	64.4	64.7	56.4	58.1	60.7	63.3	64.1	64.3	64.6	65.1	65.6	66.2
% Ch	1.4	0.5	(12.9)	3.1	4.4	4.3	1.3	0.3	0.4	0.8	0.7	0.9
U.S.	5.8	5.9	5.7	5.6	6.0	5.9	5.8	5.7	5.7	5.7	5.7	5.7
% Ch	1.1	1.1	(3.2)	(1.5)	6.4	(0.8)	(3.1)	(1.1)	(0.4)	0.1	0.4	0.4
Government												
Oregon	294.8	298.9	300.7	292.9	295.9	298.1	302.8	308.0	312.4	316.6	321.0	324.4
% Ch	(4.8)	1.4	0.6	(2.6)	1.0	0.8	1.6	1.7	1.4	1.3	1.4	1.0
U.S.	22.4	22.6	22.9	22.9	23.1	23.2	23.4	23.5	23.7	23.8	24.0	24.1
% Ch	0.4	0.6	1.2	0.1	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6
Federal Government												
Oregon	28.1	28.5	28.9	27.7	27.7	27.8	27.8	27.8	27.9	27.9	27.9	28.0
% Ch	(0.3)	1.6	1.2	(4.2)	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1
U.S.	2.8	2.8	3.0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
% Ch	(0.2)	1.2	4.6	(4.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
State Government, Oregon												
State Total	39.5	40.7	41.1	40.9	41.7	41.9	42.2	42.5	42.9	43.5	44.1	44.5
% Ch	(29.8)	3.0	1.2	(0.5)	1.8	0.6	0.6	0.8	1.1	1.3	1.4	0.8
State Education	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
% Ch	1.9	5.2	5.0	0.2	0.8	0.5	0.8	0.5	0.2	0.4	0.5	0.5
Local Government, Oregon												
Local Total	227.2	229.7	230.7	224.3	226.5	228.5	232.8	237.7	241.6	245.2	249.0	252.0
% Ch	0.8	1.1	0.4	(2.8)	1.0	0.9	1.9	2.1	1.7	1.5	1.5	1.2
Local Education	132.7	134.0	135.0	130.2	131.6	132.5	134.7	137.2	139.2	141.0	142.4	143.4
% Ch	(0.0)	0.9	0.8	(3.6)	1.1	0.6	1.7	1.8	1.4	1.3	1.0	0.7

Docket No. UE 374

Jun 2020 - Other Economic Indicators

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
GDP (Bil of 2012 $),												
Chain Weight (in billions of $)	18,638.2	19,073.1	18,047.2	19,189.0	19,955.6	20,279.7	20,549.2	20,935.3	21,359.4	21,800.6	22,272.8	22,749.9
% Ch	2.9	2.3	(5.4)	6.3	4.0	1.6	1.3	1.9	2.0	2.1	2.2	2.1
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2012=100	110.4	112.3	114.0	115.6	117.3	119.6	122.3	125.0	127.8	130.7	133.6	136.7
% Ch	2.4	1.8	1.5	1.4	1.5	2.0	2.2	2.2	2.2	2.3	2.3	2.3
Personal Consumption Deflator,												
Chain Weight U.S., 2012=100	108.1	109.7	110.6	112.2	114.4	117.0	119.5	122.1	124.5	127.0	129.4	131.8
% Ch	2.1	1.4	0.9	1.5	2.0	2.2	2.2	2.1	2.0	1.9	1.9	1.9
CPI, Urban Consumers,												
1982-84=100												
West Region	263.3	270.3	272.3	278.1	285.7	293.5	300.9	308.3	315.8	323.2	330.6	338.2
% Ch	3.3	2.7	0.7	2.1	2.7	2.7	2.5	2.5	2.4	2.3	2.3	2.3
U.S.	251.1	255.7	257.4	262.7	269.8	277.1	283.8	290.6	297.2	303.7	310.2	316.8
% Ch	2.4	1.8	0.7	2.1	2.7	2.7	2.4	2.4	2.3	2.2	2.1	2.1
Oregon Average Wage												
Rate (Thous $)	55.4	57.1	59.7	59.6	61.4	64.0	66.8	69.7	72.6	75.7	78.9	82.2
% Ch	3.7	3.0	4.5	(0.1)	3.0	4.2	4.4	4.3	4.3	4.3	4.2	4.2
U.S. Average Wage												
Wage Rate (Thous $)	59.7	61.6	62.4	65.3	67.5	69.5	72.0	74.8	77.9	81.1	84.4	87.8
% Ch	3.4	3.2	1.4	4.6	3.4	3.0	3.5	4.0	4.1	4.1	4.1	4.1
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	423.1	443.2	457.5	462.2	473.2	488.0	503.6	519.2	535.4	553.0	572.5	592.4
% Ch	7.8	4.8	3.2	1.0	2.4	3.1	3.2	3.1	3.1	3.3	3.5	3.5
FHFA National Housing Price Index												
1991 Q1=100	260.5	274.1	283.9	289.1	296.0	304.0	312.3	320.7	329.1	337.9	347.3	357.6
% Ch	6.5	5.2	3.6	1.8	2.4	2.7	2.7	2.7	2.6	2.7	2.8	3.0
Housing Starts												
Oregon (Thous)	19.6	20.7	16.2	16.7	18.9	21.4	21.9	22.2	21.9	21.9	21.8	21.9
% Ch	1.4	5.9	(21.7)	3.0	13.3	13.1	2.3	1.4	(1.2)	(0.0)	(0.4)	0.2
U.S. (Millions)	1.2	1.3	1.1	1.1	1.3	1.2	1.2	1.2	1.2	1.1	1.1	1.1
% Ch	3.4	3.9	(17.0)	4.0	12.3	(1.2)	(2.8)	0.0	(2.7)	(2.4)	(0.3)	0.3
Other Indicators												
Unemployment Rate (%)												
Oregon	4.1	4.1	15.3	14.7	11.4	7.6	4.6	4.2	4.3	4.4	4.3	4.3
Point Change	0.0	(0.0)	11.2	(0.6)	(3.3)	(3.8)	(3.0)	(0.4)	0.2	0.0	(0.0)	(0.0)
U.S.	3.9	3.7	8.0	7.9	4.3	3.6	4.0	4.3	4.3	4.3	4.3	4.2
Point Change	(0.5)	(0.2)	4.4	(0.2)	(3.6)	(0.7)	0.4	0.3	0.0	(0.0)	(0.0)	(0.0)
Industrial Production Index												
U.S, 2012 = 100	108.6	109.5	96.1	96.4	101.1	103.0	104.0	105.7	107.9	109.9	111.8	113.8
% Ch	3.9	0.9	(12.2)	0.3	4.8	2.0	1.0	1.6	2.0	1.8	1.7	1.8
Prime Rate (Percent)	4.9	5.3	3.5	3.3	3.3	3.3	3.3	3.3	3.6	4.2	4.7	5.2
% Ch	19.7	7.7	(33.0)	(8.2)	0.0	0.0	0.0	0.3	11.9	13.7	12.1	10.8
Population (Millions)												
Oregon	4.20	4.24	4.27	4.29	4.32	4.36	4.40	4.43	4.47	4.51	4.54	4.58
% Ch	1.3	1.0	0.7	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
U.S.	327.7	330.1	332.4	334.7	337.1	339.4	341.6	343.9	346.1	348.3	350.5	352.6
% Ch	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6
Timber Harvest (Mil Bd Ft)												
Oregon	4,064.0	3,860.0	3,156.5	3,387.9	3,553.5	3,635.9	3,692.8	3,787.6	3,821.6	3,847.3	3,871.3	3,895.5
% Ch	5.5	(5.0)	(18.2)	7.3	4.9	2.3	1.6	2.6	0.9	0.7	0.6	0.6

CASE: UE 374
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2600

Rebuttal Testimony

July 24, 2020

Q. Please state your name, occupation, and business address.

A. My name is Brian Fjeldheim. I am a Senior Financial Analyst employed in the Energy Rates and Accounting Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you already provided testimony in this case?

A. Yes, I previously provided testimony in this case in Exhibit Staff/300, Fjeldheim.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to PacifiCorp's positions on the issues of property and liability insurance costs, taxes (other than income), Klamath Hydroelectric Settlement Agreement (KHSA) and Klamath River Restoration Corporation (KRRC) duplicate Test Year expenses and capital additions, and cybersecurity expenses.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Staff/2601 KHSA/KRRC Capital Investments – Associated PacifiCorp workpapers/exhibits.

Staff/2602 Cyber Security – Associated PacifiCorp workpapers.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Property and Liability Insurance Costs 2
Issue 2. Taxes (Other Than Income) 5
Issue 3. KHSA and KRRC Capital Investments 8
Issue 4. Cyber Security 10
Issue 5. Other Issues Raised in Staff Opening Testimony 11

ISSUE 1. PROPERTY AND LIABILITY INSURANCE COSTS

Q. Please summarize Staff's recommendation on property and liability insurance costs.

A. In Opening Testimony, Staff recommended [**BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**.

Q. Did the Company change its Test Year insurance premium expense in its reply filing?

A. Yes. The Company subsequently increased its Oregon allocated Test Year property insurance premium expense by $70 thousand and injures and damages premiums by $1.018 million, a total increase of $1.088 million. In its original filing, the Company proposed $11.621 million in combined insurance premiums and in reply testimony, the Company proposes a Test Year combined total of $12.709 million.[1]

[1] See Company Excel workpaper "OR GRC JAM Dec 2021 Test Period_R", tabs "Report", "Adjustments", and "Adj Summary".

Q. Did the Company provide additional evidence to support the increased premiums?

A. Generally, no. The Company provided updated workpapers[2] with the higher Oregon allocated Test Year premiums, but did not supply additional data to support the higher premiums. In the Company's Reply Testimony, Ms. Shelley McCoy states

> The Company has included an update to the liability and property insurance premiums, reflecting the August 2020 insurance renewals. The originally filed case included premiums effective August 2019; however, this update to the August 2020 premiums reflects the level of insurance premiums that will be in place for a majority of the 2021 Test Period. Increased premiums are primarily due to wildfire risk.[3]

The Company provides no further evidence to support the Test Year increase.

Q. Does Staff have additional concerns with the Company's proposed increase in Test Year premiums?

A. Yes. The Company's updated premium increase effectively changes the Company's proposed Test Year for this issue. In its original filing, the Company elected to use expense data from its Base Year ending June 30, 2019, and insurance premiums that were effective August of 2019.[4] By revising its data for insurance premiums for the Test Year, the Company effectively "moves the goal posts" in this case. Introducing new data at such a late date is inappropriate as Staff is unable to perform significant investigation of the Company's revised Test Year expenses. The Company chooses a Base Year

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[2] Company's Excel workpapers "OR GRC JAM Dec 2021 Test Period_R" and "4.4_R – Insurance Expense".
[3] Exhibit PAC/3100, McCoy/21 at 9 – 13.
[4] *Id.*

as the basis for the case, and files appropriate changes and updates to that when it makes its initial filing. This is to reflect a normalized Test Year. Picking some elements to update in the Base Year, but not others, amounts to cherry-picking, for which the Company has offered no support. Based on the Company's initial filing and Staff's subsequent review, the **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**. As such, there was no opportunity to consider the $1.088 million increase in total insurance premiums with the Company or parties.

Q. What does Staff recommend?

A. Regarding the **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**.

Regarding the Company's revised Oregon allocated insurance premium increase totaling $1.088 million, due to the dearth of supporting evidence combined with the introduction of new data at such a late juncture in the proceeding, Staff recommends the Company's proposed increase be excluded from consideration and that the Company's originally filed Test Year premiums totaling $11.621 million be considered.

1 **ISSUE 2. TAXES (OTHER THAN INCOME)**

2 **Q. Please summarize the individual elements Staff considered in previous**
3 **testimony for this issue.**

4 A. Staff reviewed and analyzed the Company's proposed rate factors for the
5 regulatory fee imposed by the OPUC, franchise fees, the Oregon
6 Department of Energy (ODOE) energy supplier fee, and property taxes.[5]
7 Staff proposed using a three year average, to include the Company's filed
8 Base Year ended June 30, 2019.

9 Staff recommended:

10 i. The OPUC rate be reduced from 0.400 percent to 0.350 percent,
11 resulting in a ($669 thousand) reduction.

12 ii. The franchise fee rate be reduced from 2.350 percent to
13 2.337 percent, a ($175 thousand) decrease.

14 iii. The ODOE rate be reduced from 0.129 percent to
15 0.127 percent, a ($25 thousand) decrease).

16 iv. Due to the Company's refusal to provide additional years of property
17 tax data,[6] Staff was unable to complete further analysis of the
18 Company's proposed property tax rate. However, the Company is
19 proposing a lower property tax rate in the Test Year.[7]

20

[5] Exhibit Staff/300, Fjeldheim/33 – 35.
[6] Confidential Exhibit Staff/305, Fjeldheim/3.
[7] Confidential Exhibit PAC/1303, McCoy/1-3.

Q. Does the Company agree with Staff's use of a three year average for the elements discussed immediately above?

A. With the exception of property taxes, yes.[8]

Q. Does Staff have any concerns with the Company's revised Test Year proposal?

A. Yes. Similar to insurance premiums discussed in Issue 1, the Company elected to change its Base Year dataset for franchise fees and the ODOE fee to include the full 2019 calendar year. The Company's original application Base Year included 12 months of expenditure data thru June 30, 2019, and then supported this data with its original and supplemental responses to Staff SDR Nos. 057 and 058. Staff finds it inappropriate that the Company is arbitrarily changing its Base Year data set, especially at this late date, to include the full 2019 calendar year. This does not allow for adequate investigation from Staff and other parties, and amounts to cherry-picking issues to update as discussed above. This is inappropriate. Furthermore, the Company did not provide additional documentation, such as revised or supplemental filings to Staff SDR Nos. 057 or 058 for the full 2019 calendar year, to support the revised data used in its response to this issue. The Company has again "moved the goal posts" with regard to the Test Year, this time by changing the scope of the Base Year by using the full 2019 calendar year.

[8] See Exhibit PAC/3100, McCoy/20 at 10 – 12

1 **Q. What does Staff recommend?**

2 A. Staff recommends the Company be held to the expenditure and revenue
3 data presented in its original filing with the Base Year ending June 30, 2019.
4 Staff continues to recommend a three year average franchise fee rate of
5 2.337 percent and an ODOE rate of 0.127 percent be used for the Test
6 Year. The Company agrees with Staff's recommended OPUC rate of
7 0.350 percent.[9]

[9] Exhibit PAC/3100, McCoy/21 at 1 – 6.

1 **ISSUE 3. KHSA AND KRRC CAPITAL INVESTMENTS**

2 **Q. Please summarize Staff's review and recommendations on this issue.**

3 A. In Opening Testimony, Staff recommended an Oregon allocated adjustment of
4 ($167 thousand) to eliminate what Staff believed to be a duplicate depreciation
5 expenditure related to the four dams included in the KHSA. Based upon
6 clarification received in the Company's reply testimony, Staff accepts the
7 Company's position that the $167 thousand expenditure is not a duplication of
8 depreciation expense and instead represents recording of tax treatment on
9 Schedule M.[10] Staff recommends no adjustment to depreciation expense.

10 **Q. Does Staff have any additional observations regarding 2020 capital**
11 **investments?**

12 A. Yes. The purpose of the KHSA and KRRC is to dismantle and remove the
13 affected dams once the licenses of the affected dams are transferred to and
14 surrendered by KRRC. While Staff proposes no dollar adjustment, Staff wishes
15 to reiterate that continued capital investments in the dams governed by the
16 KHSA may be imprudent, especially if the dams are successfully deconstructed
17 and removed within the next three years.

18 Staff also noted, based upon the Company's original workpapers[11] and
19 response to Staff DR No. 426, the Company plans to add $504 thousand of the
20 Oregon allocated capital additions to the KHSA dams in the last two months of
21 2020. Staff recommends that a senior Company officer be required to provide

[10] Exhibit PAC/3100, McCoy/55 at 2 – 18.
[11] PAC - McCoy non confidential workpapers, Excel file "8.16 – Klamath Facilities Capital Additions".

1 written attestation affirming when the capital additions currently slated to be
2 used-and-useful in November and December of 2020 are complete. Any capital
3 addition that will not be used-and-useful by January 1, 2021, should be
4 excluded from this rate case.

1 **ISSUE 4. CYBERSECURITY**

2 **Q. Please summarize Staff's recommendation on this issue.**

3 A. In Opening Testimony, Staff recommended an Oregon allocated expense
4 reduction of ($691 thousand) due to the 2021 used-and-useful date for the
5 IronNet project.

6 **Q. Does the Company agree with Staff's recommendation?**

7 A. In general, yes. The Company agreed the used-and-useful date for the IronNet
8 project was delayed until 2021 and removed the project from the Test Year.
9 However, the Company noted that Staff's original adjustment incorrectly
10 reduced Test Year expenses by ($691 thousand) when instead it is Test Year
11 rate base that should be adjusted by ($691 thousand), along with a
12 ($30 thousand) depreciation expense adjustment, a $2 thousand depreciation
13 reserve adjustment, and a ($193 thousand) total adjustment to various
14 accumulated tax balances.[12,13] Staff witness John Fox is investigating plant and
15 tax issues in Exhibit Staff/1800, Fox.

[12] Exhibit PAC/3100, McCoy/56.
[13] Company electronic workpaper, Excel file "R_1 Remove Cyber Security Project".

1 **ISSUE 5. OTHER ISSUES RAISED IN STAFF OPENING TESTIMONY**

2 **Q. Please summarize the other issues previously raised in your Opening**
3 **Testimony.**

4 A. In Exhibit Staff/300, Fjeldheim, I also addressed health insurance benefits,
5 Directors and Officers (D&O) insurance, directors fees and expenses, fuel
6 stock, non-fuel materials and supplies, miscellaneous debits, cash and other
7 working capital, miscellaneous rate base, and customer advances for
8 construction (CAC). Staff proposed no adjustment in Opening Testimony for
9 these issues.

10 **Q. Does Staff propose to adjust any of the issues summarized immediately**
11 **above?**

12 A. Staff proposes no adjustments for these issues in Rebuttal Testimony.

13 **Q. Does this conclude your testimony?**

14 A. Yes.

CASE: UE 374
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 2601

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

Klamath ongoing capital additions description	Completion date	In-Service Cost
Eastside Flowline Removal	12/18/2020	$ 1,279,980
JC Boyle 1 and 2 Refurbish Exciters	3/30/2020	$ 508,616
Copco 2 Install Spillway Chutes	11/20/2020	$ 465,693
JC Boyle Red Barn Refurbishment	6/30/2020	$ 250,869
Iron Gate Hatchery Replace Recirc System	8/20/2020	$ 173,756
Iron Gate Intake Building Bat Mitigation	11/15/2020	$ 99,292
JC Boyle Vibration Monitoring System	7/1/2020	$ 81,720
Iron Gate Rebuild Mechanical Governor	5/20/2020	$ 77,147
Westside Plant Retaining Wall Refurb	12/1/2020	$ 75,482
Keno Replace Fish Ladder Stop Logs	7/15/2020	$ 74,813
Copco 2 Mule Wheel Replacement	6/3/2020	$ 36,973
Copco Waterline Section Replacement	5/1/2020	$ 18,764
Iron Gate Tailrace Level Indication	11/15/2020	$ 16,554
BC - Keno, Replace Fish Ladder Sensor	3/31/2020	$ 15,469
BC - Iron Gate, Replace HMI Equipment	2/1/2020	$ 12,578
Copco 11 Replace Governor Controller	4/29/2020	$ 12,475
BC - JC Boyle, Fish Screens Soft Starter	7/1/2020	$ 9,160
	Total	**$ 3,209,341**

Ref. 8.16 / Exhibit PAC 1302

Page 2 of Staff Exhibit 2601

is CONFIDENTIAL

CASE: UE 374
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2602

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

PacifiCorp
Oregon General Rate Case - December 2021
Remove Cyber Security Project

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
General Plant	397	3	(496,971)	SO	27.216%	(135,254)	R_1.1
Intangible Plant	303	3	(2,041,450)	SO	27.216%	(555,593)	R_1.1
			(2,538,420)			(690,847)	
Adjustment to Depreciation Expense:							
General Plant	403GP	3	(27,387)	SO	27.216%	(7,454)	R_1.1
Intangible Plant	404IP	3	(83,250)	SO	27.216%	(22,657)	R_1.1
			(110,637)			(30,111)	
Adjustment to Depreciation Reserve:							
General Plant	108GP	3	2,520	SO	27.216%	686	R_1.1
Intangible Plant	111IP	3	3,469	SO	27.216%	944	R_1.1
			5,989			1,630	
Adjustment to Tax:							
Schedule M Adj - General Plant	SCHMAT	3	(27,387)	SO	27.216%	(7,454)	
Schedule M Adj - Intangible Plant	SCHMAT	3	(83,250)	SO	27.216%	(22,657)	
			(110,637)			(30,111)	
Schedule M Adj - General Plant	SCHMDT	3	(99,394)	SO	27.216%	(27,051)	
Schedule M Adj - Intangible Plant	SCHMDT	3	(408,290)	SO	27.216%	(111,119)	
			(507,684)			(138,169)	
DIT Expense - General Plant	41010	3	(17,704)	SO	27.216%	(4,818)	
DIT Expense - Intangible Plant	41010	3	(79,916)	SO	27.216%	(21,750)	
			(97,620)			(26,568)	
ADIT - General Plant	282	3	1,362	SO	27.216%	371	
ADIT - Intangible Plant	282	3	6,147	SO	27.216%	1,673	
			7,509			2,044	

Description of Adjustment:

This adjustment removes the IronNet cyber security project from rate base because the in-service date has moved beyond December 2020 as stated in OPUC 335.

PacifiCorp
Oregon General Rate Case - December 2021
Remove Cyber Security Project

Electric Plant in Service

	Account	Factor	Dec-20	
General Plant	397	SO	496,971	**Ref R_1**
Intangible Plant	303	SO	2,041,450	**Ref R_1**

Depreciation Expense**

	Account	Factor	Dec-20	
General Plant	403GP	SO	27,387	**Ref R_1**
Intangible Plant	404IP	SO	83,250	**Ref R_1**

Depreciation Reserve

	Account	Factor	Dec-20	
General Plant	108GP	SO	(2,520)	**Ref R_1**
Intangible Plant	111IP	SO	(3,469)	**Ref R_1**

**Composite Depreciation Rate - General Plant*	*5.221%*
**Composite Depreciation Rate - Intangible Plant*	*4.078%*
***Proposed Composite Depreciation Rate - General Plant*	5.511%
*** Proposed Composite Depreciation Rate - Intangible Plant*	4.078%

UE 374/PacifiCorp
May 11, 2020
OPUC Data Request 335

OPUC Data Request 335

Cyber Security
Does the current rate case include cybersecurity investments/expenditures? If yes, please provide:

(a) A description of the expenditures.

(b) The total dollar amount and the Oregon allocated dollar amount.

(c) A brief synopsis of how these expenditures will improve/strengthen the Company's cybersecurity defenses.

Response to OPUC Data Request 335

Yes, cybersecurity expenditures are included in this general rate case.

(a) IronNet is a collective defense solution. IronNet takes the behavioral intelligence derived from identified cyber anomalies in IronDefense and shares it across an industry sector to deliver machine-speed visibility of potential threat campaigns targeting participant industry peers.

(b) The implementation project will not occur in 2020, as projected in the rate case, and is now projected to occur in 2021. The project costs included in the case are approximately $2.5 million total company and $691 thousand Oregon allocated.

(c) Using IronNet, security analysts with shared interests can work together in near-real-time to collaboratively defend their enterprises.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

CASE: UE 374
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2700

Rebuttal Testimony

July 24, 2020

Q. Please state your name, occupation, and business address.

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Energy Economic Analysis Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Are you the same Mitchell Moore who offered direct testimony on behalf of Staff?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address PacifiCorp's reply testimony and intervenors' opening testimony on the issues of vegetation management (VM) and a cost recovery mechanism relating to wildfire mitigation.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/2701, Exhibit Staff/2702, Exhibit Staff/2703, and all of which contain copies of responses to Staff Data Requests. Exhibit Staff/2704 is a chart of safety clearance violations, updated with 2020 inspection results.

Q. How is your testimony organized?

A. I organize my testimony as follows:

Issue 1, Vegetation Management Program 2
Issue 2, PacifiCorp's Wildfire Cost Recovery Rate Mechanism 7
Issue 3, PacifiCorp's Capital Investment Plan 16
Issue 4, Review of Other Parties Direct Testimony on Vegetation Management and Wildfire Mitigation 26

ISSUE 1, VEGETATION MANAGEMENT PROGRAM

Q. Please summarize PacifiCorp's rebuttal testimony on vegetation management.

A. PacifiCorp's rebuttal testimony on vegetation management is presented in PAC/2900, Lucas 12-24. My bullet point summary of the PacifiCorp rebuttal testimony is presented below:

1. Lucas agrees that PacifiCorp has a legal obligation to maintain a robust Vegetation Management Program (VMP). (PAC/2900, Lucas/12.)
2. PacifiCorp's objective is to have a VMP that is professional, cost-effective and environmentally conscientious. (PAC/2900, Lucas/13.)
3. The program covers a distribution and transmission lines and is coordinated on a circuit basis. (PAC/2900, Lucas/15.)
4. PacifiCorp recognizes that there are problems with its VMP and is instituting changes including creating an east and west VM group and managed locally. (PAC/2900, Lucas/18-19.)
5. PacifiCorp is now using data analytics. (PAC/2900, Lucas/19.)
6. PacifiCorp initiated a pilot program to use Light-Imaging Detection and Ranging (LIDAR).
7. A budget approach is not recommended as weather can affect the level of needed VM. (PAC/2900, Lucas/21.)
8. To address lag in potential recovery of a deferral mechanism, PacifiCorp witness Wilding proposes an alternate recovery mechanism. (PAC/2900, Lucas/22.)

Q. What level of violations does Staff consider to be reasonable for a VM program that is prudent?

A. Given that VM is a safety issue, Staff finds that any VM program should strive for as few violations as possible. However, as discussed further below, Staff finds that for PacifiCorp, in light of its historical performance under its VMP, fewer than 75 violations would be reasonable.

Q. Does PacifiCorp provide any projection as to when it would get its VM violations back to a reasonable level?

A. No. While it is good that PacifiCorp admits it has problems with its VMP and is making structural and analytical changes, the Company does not provide any projection as to when the VM will be under control. The Company also fails to provide proposed metrics for review of VMP performance.

Q. Did you ask any data requests to obtain better information as to when PacifiCorp might achieve VM violations of 100 or less?

A. Yes. Staff Data Requests Nos. 677 and 691 both seek such information. The Company's responses to these requests are attached as pages 1 and 2 to Exhibit Staff/2702. PacifiCorp declined to give a specific date by which clearance violations would be below 100, but instead stated it had a three-year plan to reduce the number of clearance violations.

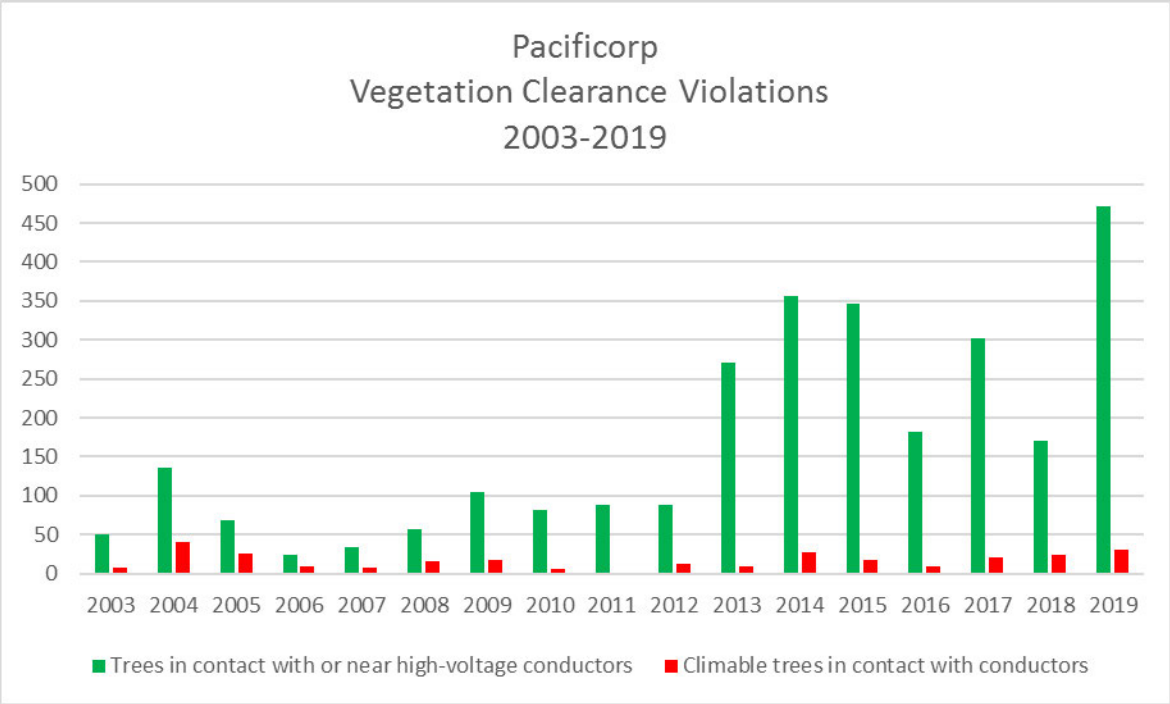
Q. Do you have a proposal for a VMP performance metrics?

A. Yes. I recommend the following annual metrics:

- Violation Level I is when VM violations exceed 75.
- Violation Level II is when VM violations exceed 150, and

- Violation Level III is when VM violations exceed 200.

I will discuss the use of these metrics when I discuss Staff's proposed Wildfire and Vegetation Management Rate Recovery Mechanism, below. To develop these metrics, I relied on information included in my direct testimony showing a history of VM violations:[1]



From the above table, we can observe that for much of the time period from 2003 through 2012, the number of violations was less than 75 in most years. Only in two years are they clearly above that level. From 2013 on, the VM violations frequently was above 250 and never fell below 150.

[1] See Exhibit Staff/600, Moore/13.

In addition, Commission safety staff recently concluded its annual review of PacifiCorp's vegetation clearances and has documented 376 safety violations to date in 2020.[2]

Q. Did any other party discuss VM?

A. No.

Q. What level of expenses is PacifiCorp requesting for VM?

A. PacifiCorp has included $29,434,782 of expenses associated with VM expenses for the 2021 test period. This is a sum of $20,523,782 from its direct case and an additional $8.8 million in the Company rebuttal case.[3]

Q. Does any of the $8.8 million in additional expenses PacifiCorp is requesting for VM involve reducing the level of clearance violations?

A. No. Staff Data Request No. 681, a copy of which is attached as OPUC/2702, Moore/3, asked PacifiCorp whether any VM expense was catch-up costs incurred to reduce the level of clearance violations. The Company stated none of the $8.8 million in expenses is due to rectifying past clearance violations.

Q. Does Staff have a recommendation related to VM expense requested in this case?

A. Staff does not have adjustments to the Company's requested VM expenses in this case as set forth in its Reply Testimony. However, rather than include all

[2] See Exhibit Staff/2704, Moore/1 – Commission Safety Staff updated graph with 2020 vegetation clearance violation results.
[3] See Exhibit Staff/2702, Moore/3 Company's response to Staff Data Request No. 611; and PAC/3100, McCoy/26, line 4 for the additional $8.8 million.

of these costs in base rates, Staff proposes that VM costs be part of an overall Wildfire and Vegetation Management Rate Recovery Mechanism, discussed in the next section.

1 **ISSUE 2, PACIFICORP'S WILDFIRE COST RECOVERY RATE MECHANISM**

2 **Q. Did the Company offer rebuttal testimony on its proposed Wildfire**
3 **Cost Recovery Rate Mechanism?**

4 A. Yes. PacifiCorp witness Mr. Wilding discusses PacifiCorp's revised Wildfire
5 Mitigation and Vegetation Management Cost Recovery Mechanism
6 beginning on page 45 of his reply testimony.

7 **Q. Did the Company support many of the recommendations included in**
8 **Staff's opening testimony?**

9 A. Yes. The Company agreed to the following Staff recommendations:
10 1) Using a deferral format for both Wildfire Mitigation and VM. (PAC/2000,
11 Wilding/46).
12 2) Providing a much more reasonable timeframe for review of prudence
13 prior to the time amortization begins. (PAC/2000, Wilding/47).
14 3) Using an independent expert (IE), although the role of the IE still needs
15 to be determined. (PAC/2900, Lucas/11).

16 **Q. What Staff recommendations did the Company not support?**

17 A. The Company disagreed to the following Staff recommendations:
18 1) The amount subject to deferral. (PAC/2000, Wilding/46.)
19 2) Application of an earnings test. (PAC/2000, Wilding/48.)

20 **Q. Based on your review of the Company's testimony do you have an**
21 **alternative Vegetation Management and Wildfire Mitigation Cost**
22 **Recovery Mechanism?**

23 A. Yes. I recommend the Commission adopt the following:

I. Include in base rates the revenue requirements of $26.58 million of the $33.225 million PacifiCorp requests for VM and Wildfire Mitigation O&M expenses projected for the 2021 test period. All expenses and rate of return components of Wildfire Mitigation capital expenditures through December 31, 2020, that are found prudent would also be included in base rates.[4] Staff discusses the prudence of Wildfire Mitigation capital expenditures below.

II. Each year, beginning with 2021, all expenses above the amount of $26.58 million of PacifiCorp's requests for VM and Wildfire Mitigation O&M costs projected for the 2021 test period, and costs for an Independent Evaluator would be included in an annual deferral.[5] The annual revenue requirement effects of VM and Wildfire Mitigation capital expenditures would also be included in each annual deferral.

III. Amortization of Section II would occur on the schedule as proposed in Mr. Wilding's testimony (PAC/2000, Wilding/47) and be subject to the following:

A. Amortization depends on PacifiCorp's performance relative to the following VM performance metrics:

I. Violation level I is when VM violations exceed 75;

II. Violation level II is when VM violations exceed 150; and,

[4] See Exhibit Staff/2702, Moore/4-6 – Company response to Staff Data Request 678 provides 2021 expenses for Vegetation Management and Wildfire Mitigation.
[5] The first $28.8 million of prudently incurred costs are not in the deferral mechanism as they are already included in base rates.

III. Violation III is when VM violations exceed 200.

IV. Each year, beginning in 2021, for prudently incurred expenses of more than $26.58 and up to $33.225 million (for a total of $6.645 million) of the Section II annual amounts and deferred in the Wildfire Rate Mechanism and found to be prudently incurred, the following earnings test would be applied.[6]

A. No earnings test is applicable if VM violations are below Violation Level I.

B. An earnings test is applied with the ROE equal to Commission UE 374 authorized ROE minus 100 basis points where the Company is found by the Commission to be at or above Violation Level I and less than Violation Level II.

c. An earnings test is applied with the ROE equal to Commission UE 374 authorized ROE minus 150 basis points where the Company is found by the Commission to be at or above Violation Level II and less than Violation Level III.

d. An earnings test is applied with the ROE equal to Commission UE 374 authorized ROE minus 200 basis points where the Company is found by the Commission to be equal to or greater than Violation Level III.

e. Each of the above thresholds will have the basis points adjusted by adding an additional minus 50 basis points should any of the VM

[6] A prudence review would always first take place to identify the dollars eligible for amortization.

clearance violations occur in a Fire High Consequence Area (FHCA). For example, for Violation Level II and above the earnings test would be the UE 375 authorized ROE minus 250 basis points.

V. For any prudently incurred expenses above $33.225 million as discussed above:

a. The Company may amortize in rates the revenue requirement effect of such costs subject to an earnings test set at the Commission's authorized UE 374 ROE.

b. Notwithstanding subparagraph (a) above, where Violations occur at or above Level II and at least one of the violations occurs in a FHCA zone, an earnings test is applied with the ROE equal to Commission UE 374 authorized ROE minus 50 basis points

VI. No earnings test shall apply to the deferred costs related to the Independent Expert.

VII. Expenses found to be prudently incurred in a year but not eligible for amortization, due to application of the earnings test, shall not roll-over for cost recovery in future years.

Q. What is the source for your dollar values listed above? For example, the $33.225 million and $26.58 million?

A. PacifiCorp's response to Staff Data Request No. 678, a copy of which is attached as OPUC/2702, Moore/4-6, provides the projected expenses for VM and Wildfire Mitigation for the 2021 test period. The table below summarizes the information in that data request response.

	Total Vegetation Management	Wildfire Mitigation	Total
Base Period Expenses	$19,661		$19,661
Incremental Expenses	$8,760	$4,803	$13,564
Total	$28,422	$4,803	$33,225

Q. What is Staff's proposal regarding the role of the IE?

A. Staff proposes the IE would help PAC develop its wildfire mitigation plan, review the plan and provide comment to the Commission, and finally the IE would review PacifiCorp's spending pursuant to that plan and file an annual report detailing its findings.

Q. Why are you recommending using the Commission-authorized ROE for purposes of the earnings test for the prudently deferred amounts greater than $33.225 million of expenses?

A. For three reasons. First, it seems reasonable to appropriately support Wildfire Mitigation efforts as it is a key concern for the State of Oregon. On March 10, 2020, the Governor issued Executive Order 20-04, in which the Governor directed the OPUC to,

> Evaluate electric companies' risk-based wildfire protection plans and planned activities to protect public safety, reduce risks to utility customers, and promote energy system resilience in the face of increased wildfire frequency and severity, and in consideration of the recommendations made by the Governor's Council on Wildfire Response 2019 Report and Recommendations.[7]

The OPUC developed a response to the Governor's Executive Order to carry out the directive consistent with OPUC statutes. That framework was

[7] Page 8, Section 5.B.4 of the Governor Executive order 20-04

1 published May 15, 2020, and on page 11, begins a discussion on Wildfire
2 Mitigation. It is clear from that discussion that the Commission should
3 promote the safety of the public, reduce risks to utility customers and
4 enhance the resiliency of the electric power system from the threat of
5 wildfires. By allowing for cost recovery up to the utility's authorized rate of
6 return, the Commission is supporting that objective through providing the
7 utility a greater opportunity to earn additional dollar income for its
8 shareholders through its authorized return on additional capital expenditures
9 with virtually no regulatory lag and by allowing dollar-for-dollar recovery of
10 prudent wildfire mitigation and VM expenses. This strikes an appropriate
11 balance between the interests of ratepayers and shareholders.
12 Second, the activities pursued by PacifiCorp should benefit having
13 agreement among the parties regarding using an Independent Expert (IE) to
14 evaluate and comment on the PacifiCorp Wildfire Mitigation Plan as well as a
15 review by the IE of PacifiCorp's actions/compliance with that plan. Staff finds
16 it beneficial for the Company to obtain input on its measures/actions proposed
17 from the IE by providing the IE a draft of its proposed plan and allowing some
18 time for review and comment. Having an IE should help prevent wasteful
19 spending for purposes of increasing profits rather than mitigating the risk of
20 wildfires. The Company Plan and IE review would be on September 1.
21 That is PacifiCorp would submit a plan for 2022 activities on
22 September 1. The IE would also submit a report to the OPUC on September
23 1 assessing the performance of the Company for the prior July through June

prior period. Based on the IE report as well as Staff and other parties' analysis of Company expenditures, the Company could face a prudence disallowance for Wildfire Mitigation expenditures (and VM expenditures above the 2021 test year levels). Again as stated previously, we expect the Company and the IE to spend special attention and increase focus on the Fire High Consequence Areas as these areas pose the greatest risk to life and property. If or when the Commission undertakes a rulemaking or some other process to establish a policy around wildfire mitigation, PacifiCorp's cost recovery mechanism could be revisited at that time, if appropriate.

Third, the OPUC is directed in the Executive Order No. 20-04, paragraph B.3, to mitigate the energy burden experienced by utility customers while ensuring system reliability and resource adequacy. When deferred accounting is used, which provides the utility a means to avoid regulatory lag and recover costs for Wildfire Mitigation and Vegetation Management, it is reasonable to conduct an earnings test as required under the deferred accounting statute and as consistent with longstanding Commission policy.

The earnings test generally protects customers from an increase in rates when the Company's earnings are said to otherwise be within a reasonable range of its authorized rate of return. In some instances, the Commission finds a reasonable range to include a lower rate of return than authorized; however, in this case, Staff finds that setting the earnings threshold equal to the Commission's authorized ROE ensures customers that there is a limit to the level of costs that are recoverable in rates through the

Staff-proposed Vegetation Management and Wildfire Mitigation Recovery Mechanism.

Q. Why do you propose a lower earnings test threshold if VM clearance violations occur in a FHCA?

A. Staff is recommending an increased focus on FHCA because these areas pose a greater risk to property and life and are designated as such. Providing a lower earnings threshold should provide the Company with an incentive to ensure that the VM clearance violations are eliminated in the FHCA.

Q. What does the Company project for costs for VM and Wildfire Mitigation beyond 2021?

A. Staff Data Request No. 678, a copy of which is attached as Staff/2702, Moore/4-6, provides projections of costs beyond 2021. PacifiCorp states that the level of expenses incurred on 2021 should likely continue through 2025. However, the Company projects substantive capital investments for Wildfire Mitigation. PacifiCorp's projections are provided below.

Oregon-Allocated Forecast

('$000)			2021	2022	2023	2024	2025
OR	Dist	Capital	$25,324	$26,012	$33,654	$48,160	$48,150
OR	Trans	Capital	$1,306	$915	$577	$571	$571
CA		Capital	$3,119	$2,676	$2,349	$0	$0
WA		Capital	$0	$0	$0	$0	$0
UT		Capital	$6,915	$6,186	$4,082	$1,533	$1,468

Q. Does the Staff-proposed rate mechanism provide any other protections against wasteful spending?

A. Yes. Any expenditures on Vegetation Management and Wildfire Mitigation above the $26.58 million is subject to the deferral mechanism and will be reviewed for prudence. Staff and other parties will have an opportunity each year to evaluate and conduct discovery on the prudence of Company actions including those hardening the system.

ISSUE 3, PACIFICORP'S CAPITAL INVESTMENT PLAN

Q. In its opening testimony Staff expressed concern with the Company's proposed capital expenditures. Have those concerns been addressed by PacifiCorp in testimony or in responses to data requests?

A. No. Staff remains concerned about the extent of the proposed spending, particularly on insulated conductors in this case and in future years. The Company continues to provide vague and unhelpful responses to Staff's repeated data requests intended to understand specifically what the Company is proposing, including information that demonstrates the prudence of the proposed expenditures.[8] In addition, PacifiCorp's proposed line replacement projects far exceed any similar projects the Company is doing in its other states, including Washington and California.

The table below compares the relative miles of transmission and distribution line replacement in FHCA-equivalent zones in PAC's other service jurisdictions.[9]

Miles of lines overhead conductors		
	Distribution	Transmission
OR	2038	0
CA	164	23
WA	12	0
UT	0	111
ID	0	0
WY	0	0

[8] See Exhibit Staff/2702, Moore/7-10– Company responses to staff data request nos. 443, 516, 517, 521 and 686, and Exhibit Staff/2701, Moore/1-3 – Company response to staff data request no. 612.
[9] See Exhibit Staff/2702, Moore/11-12 – Company response to staff data request nos. 601-602.

Q. Does the Commission have guidelines regarding the type of information that a utility must provide to justify capital spending?

A. Yes. In adjudicating a general rate case for Avista Utilities (UG 288), the Commission shared Staff's concern about the utility providing sufficient support for its capital investment proposal in Order No. 16-109. In that Order, the Commission provided the following guidance that a gas utility should provide in support of its capital investment:

> *(*1) a comprehensive cost-benefit analysis of whether and when the investment should be built; (2) evaluation of a range of alternative build dates and the impact on reliability and customer rates; (3) credible evidence on the likelihood of disruptions based on historical experience; (4) evidence on the range of possible reliability incidents; (5) evidence about projected loads and customers in the area; and (6) adequate consideration of alternatives, including the use of interruptibility or increased demand-side measures to improve reliability and system resiliency.[10]

Q. That Order refers to a gas utility. Does Staff believe that similar guidelines would apply to an electric utility?

A. Yes. While some of the Commission's guidelines in Order No. 16-109 may not apply in this particular case, the Order demonstrates that the prudence standard is fairly significant. It also conveys the general requirement for a utility to provide sufficient information such that Staff may understand what specifically the projects entail, why those projects will meet the expected criteria, and why the cost of those projects are justified by the risk that will be mitigated. This general requirement applies in this case.

[10] Commission Order No. 16-109.

Q. Has the Company met its burden in demonstrating the necessity and prudence of its proposed projects?

A. I do not believe so. The information supplied thus far includes: the Table 1 in PAC/1100, Lucas/6 that provides a high-level description of types of projects and associated amounts; a high-level map showing the general geographic area of FHCA zones in Oregon, a list of projects with a cursory description and no context. There is no information provided that demonstrates the Company has looked at Wildfire Mitigation in a holistic manner, considered alternatives, and developed a comprehensive, well-considered plan that evaluates the specific risks to its facilities and addresses them in a least cost, least risk manner.

Q. What data requests have been issued, and how has the Company responded?

A. Staff DR No. 443 requested a system map that "identifies specifically the facilities targeted for replacement, or other capital investments." This question asked the Company to provide a system map showing which transmission and distribution facilities have been targeted by the Company for wildfire mitigation activities.

The Company responded to the data request by providing a blown-up version of the same information that was included as an exhibit PAC/1101, Lucas/1, which identified the geographical FHCA zones in PacifiCorp's

1 Oregon service territory.[11] There was no reference to any PacifiCorp facility
2 on the map provided.
3 Staff followed up with DR No. 612 requesting a breakdown of
4 individual capital projects included in this case that would include a
5 description of the projects, including location. The Company responded with
6 a list of project names, with no locations that would have any meaning outside
7 the Company, estimated amounts, and estimated in-service dates
8 representing over $40 million in capital costs across its jurisdictions.[12].
9 Staff noted in its opening testimony the lack of information provided by
10 PacifiCorp thus far, and provided specific examples of the information
11 requested and the Company response. Staff was concerned that because
12 PacifiCorp did not provide specific information regarding what projects it was
13 contemplating for 2020, that the Company did not appear to have a
14 comprehensive plan that could be evaluated for prudence. Moreover, it isn't
15 clear that the Company has conducted its own prudence evaluation of these
16 projects.
17 In opening testimony Staff wrote:
18 "Staff believes it is premature to approve a major
19 capital investment spending program that has not yet developed
20 into a plan and for which supporting data is not yet available in
21 order to evaluate the relative risk mitigation against the cost."

[11] See Exhibit Staff/2702, Moore/7 – Company response to Staff DR No. 443
[12] See Exhibit Staff/2701, Moore/1-3 – Company response to staff data request no. 612

After the Company's rebuttal testimony, Staff followed up a third time with the more specific request that the Company "describe in detail the specific capital projects it has included in this case." The Company responded by pointing back to its previous answer in response to Staff DR. No. 612. [13]

In Staff DR Nos. 516, 517, and 521 Staff was hoping to get more clarity on where in the FHCA zones the Advanced Protection and Control relay systems would be located, and how those systems would help identify faults and locate downed cable. The concern is that PacifiCorp may not have the necessary communication systems in place to utilize the advanced features of the proposed relays.[14]

The Company in its response declined to identify the locations of the proposed equipment, and with regard to its communications systems stated; " "In the event of damage, the Company is evaluating whether communication technologies could be used to convey such issues." This response raises questions about whether the advanced relay systems are a prudent expenditure.[15]

Q. What other information has Staff requested regarding PacifiCorp's proposed projects in this case?

[13] See Exhibit Staff/2702, Moore/13 – Company response to staff data request no. 686
[14] See Exhibit Staff/2702, Moore/8-10 – Company response to staff data request nos. 516, 517, and 521
[15.] See Exhibit Staff/2702, Moore/9 – Company response to staff data request no. 517

A. Staff issued a total of 48 data requests regarding the Company's wildfire mitigation proposal and vegetation management program. Among the questions were several requests seeking information about risk assessment and cost/benefit analysis the Company may have performed to support the projects.

For example, DR. No. 438 asked "has PacifiCorp performed any risk/benefit analysis to determine the level of risk that will be eliminated from the system upon completion of the transmission and distribution rebuilds, as a function of cost?"

The Company responded in part that it "has not yet developed a risk/benefit analysis supporting specific prioritization of locations for mitigation efforts that would optimize their risk/benefit."[16]

Staff DR No. 439 asked "Can PacifiCorp provide any data or studies performed by other jurisdictions, or other agencies, or analysts that demonstrate the effectiveness and the cost prudence of the system-hardening activities proposed?"

The Company responded in part: "PacifiCorp has no specific data or studies performed by other jurisdictions, agencies, or analysts that demonstrate the effectiveness and the cost prudence of the system-hardening activities proposed."[17]

[16] See Exhibit Staff/2702, Moore/14 – Company response to staff data request no. 438
[17] See Exhibit Staff/2702, Moore/15 – Company response to staff data request no. 439

Staff DR No. 687 asked, in reference to PacifiCorp's reply testimony PAC/2900, Lucas/6: "please provide any efficacy studies and mitigation results that have been documented by all of the jurisdictions cited in the exhibit that have employed covered conductors."

The Company responded: "PacifiCorp is not aware of any cost efficacy studies for the various locations in which covered conductor is installed."[18]

Q. Did PacifiCorp provide any cost benefit analysis regarding the installation of covered conductors?

A. Not for its own projects, but the Company did, in response to Staff DR No. 688, provide a copy of a risk assessment report that included wildfire mitigation produced by Southern California Edison Company.[19]

Staff DR No. 688 asked, in reference to PacifiCorp's reply testimony PAC/2902, slide 3: "please provide all cost-benefit analyses that PAC is aware of that have been performed on the installation of covered conductors in the jurisdictions cited in this slide.

The Company responded: "PacifiCorp has limited experience with the efficacy of covered conductors, but is aware of the following documents from Southern California Edison Company (SCE) that are related to the referenced exhibit." [20]

[18] See Exhibit Staff/2702, Moore/16 – Company response to staff data request No. 687.
[19] See Exhibit Staff/2703, Moore/1- Company partial response to Staff data request No. 688 – attachment 1.
[20] See Exhibit Staff/2702, Moore/17 – Company response to Staff DR No. 688

Q. What other discrepancies does Staff find in PacifiCorp's testimony and discovery response?

A. Staff was surprised to learn in the Company's response to Staff DR. No. 601 that it has no plans to replace transmission lines with covered conductors. Instead the Company states it plans to install 2,068 miles of covered conductors in its distribution system. Table in PAC/1100, Lucas/6, indicates that the Company plans to spend an Oregon-allocated $23.5 million in 2020-2022 on system hardening in its transmission system that, according to the description, appears to include installation of covered conductors.

In addition, PAC/1100, Lucas/9 specifically references rebuilding transmission lines with covered conductors.

Q. What does Staff conclude with regard to PacifiCorp's capital investment in wildfire mitigation projects?

A. Mainly, Staff concludes that the Company is being vague and opaque in its construction plans, and does not appear to have in place a comprehensive wildfire mitigation plan for its territory that can be evaluated by a third-party.

The Commission needs more information, particularly about the extent of re-conductoring that is proposed throughout its FHCA zones and how that fits together with the advanced control and protection, pole replacement, and fire-mesh wrapping projects.

Other questions remain. For example, according to the Company's response to Staff DR No. 612, it appears the Company is re-conductoring transmission lines in other states, but not in Oregon. In Oregon the Company

1 states instead it will re-conductor 2068 miles of distribution facilities, while re-
2 conductoring a total of 176 miles of distribution facilities in all its other
3 jurisdictions combined. Why such drastically different approaches in the
4 states of Washington and California from Oregon?
5 The fact that PacifiCorp does not have plans of a similar scope
6 regarding installation of covered conductors in other jurisdictions such as
7 California and Washington that also experience heightened wildfire risk, begs
8 the question of whether the scale of the Company's proposed projects is
9 warranted.
10 The Company is asking the Commission to judge as prudent $22.6
11 million in wildfire mitigation capital expenditures in 2020 for inclusion in rates
12 in this case, and will be requesting a prudence determination for an additional
13 $100 million in future years.
14 The Company has acknowledged that it has not conducted any
15 risk/benefit analysis that include consideration of alternative options to the
16 proposed projects.
17 The Company also does not address the question of the incremental
18 risk mitigation to be had by the installation of covered conductors.[21] Given
19 that the Company will still face the statutory requirement (and associated
20 expense) to maintain vegetation clearances from its facilities, the Company
21 should be required to provide analysis demonstrating the efficacy and
22 financial prudence of its plan to install covered conductors.

[21] See Exhibit Staff/2702, Moore/18 Company response to staff data request no. 692

As a result, Staff reiterates its recommendation in its reply testimony to engage a third-party expert to aid staff in its evaluation of PacifiCorp's wildfire mitigation capital investment projects. The IE expert can act as a resource to the Commission through, at a minimum, responding to Commissioner questions at a public meeting, as well as an expert who will independently review Company plans to harden its system. Ideally, the IE would help PAC develop its wildfire mitigation plan, review the plan, and review annual spending pursuant to that plan, and file an annual report.

Finally, any finding of prudence for capital costs for wildfire mitigation in this case should not be construed as setting a precedent for future recovery in a deferral docket. Staff plans to continue investigating PacifiCorp's construction plans.

1 **ISSUE 4, REVIEW OF OTHER PARTIES DIRECT TESTIMONY ON**
2 **VEGETATION MANAGEMENT AND WILDFIRE MITIGATION**

3 **Q. Did any other party submit direct testimony Wildfire Mitigation costs?**

4 A. Yes. Bradley Mullins submitted testimony on PacifiCorp's Wildfire Mitigation
5 Cost Recovery proposal.[22] Mr. Mullins states that deferrals should not be
6 used for Wildfire Mitigation costs and instead PacifiCorp use the traditional
7 general rate case approach.[23] Mr. Mullins sees wildfire risk as not being so
8 novel as to warrant deferral as they are an ordinary course of business.[24]
9 Further, shareholders benefit from Wildfire Mitigation investments and there
10 are negative shareholder performance from negative outcomes.[25]

11 **Q. Do you agree with these observations?**

12 A. No. Wildfires are an increasing risk to the safety of Oregonians, which the
13 Governor's Executive Order demonstrates is a substantive public policy issue
14 that warrants special treatment. So while the AWEC arguments are sound for
15 many business activities, Wildfire Mitigation is not viewed as one of them.

16 **Q. Does this conclude your testimony?**

17 A. Yes.

[22] Bradley Mullins testimony has been adopted by Dr. Lance Kaufman, witness for AWEC.
[23] AWEC/100, Mullins/24.
[24] AWEC/100, Mullins/25.
[25] AWEC/100, Mullins/26.

CASE: UE 374
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2701

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

OPUC Data Request 612

Please provide a breakdown of individual capital projects for 2019 and 2020 associated with wildfire mitigation that PacifiCorp proposes to include in this case. Please identify the location, description of work, and actual or expected in-service date for each project.

Response to OPUC Data Request 612

Please refer to Attachment OPUC 612, which provides a breakout of individual capital projects for 2019 and 2020 that PacifiCorp proposes to include in UE 374, including the location, description of work and actual or expected in-service date for each project. The totals by category are provided in Table 1 in Mr. David Lucas' direct testimony.

Wildfire Mitigation Program Capital Costs in UE 374 (Table 1 in Exhibit 1100)

Mitigation Program	Description	Cateogry	Location	2019 Capital Costs	2020 Capital Costs	Actual or Current Estimated In-Service Date
System Hardening	Roseburg Circuit 5U19 (1.9 miles)	Oregon Distribution	Roseburg	$ 515,000		2019
	Medford Reconductor 5R284 and 5R285	Oregon Distribution	Medford	$ 35,000		2019
	Merlin Hugo Road (16.1 miles)	Oregon Distribution	Grants Pass		$ 3,139,264	2020
	Merlin Hugo Road Tie (0.7 miles)	Oregon Distribution	Grants Pass		$ 175,000	2020
	Merlin Russel Road (14.4 miles)	Oregon Distribution	Grants Pass		$ 2,960,690	2020
	Obrien Redwood Hwy pt1 (11.5 miles)	Oregon Distribution	Grants Pass		$ 2,496,028	2020
	Selma McMullin Creek Road (11.3 miles)	Oregon Distribution	Grants Pass		$ 2,388,562	2020
	Hood River East Fork (2 miles)	Oregon Distribution	Hood River		$ 518,857	2020
	Replace identified poles based on risk modeling on all circuits within the FHCA	Oregon Distribution	All FHCA Areas		$ 1,685,600	2020
	Total Distribution system hardening			$ 550,000	$ 13,364,000	
System Hardening	Preliminary Engineering for Transmission Rebuilds	Transmission	Various UT	$ 35,000		2020
	Transmission Line Rebuild to Covered Conductor (Unscoped)	Transmission	California		$ 7,875,000	2021
	Spanish Fork - Santaquin 46kV (2.5 miles)	Transmission	American Fork UT		$ 3,000,000	2020
	Snyderville - Silver Creek 138kV (9 miles)	Transmission	Park City UT		$ 4,500,000	2020
	Columbia 11 - Horse Canyon - Woodside (20 miles)	Transmission	Price UT		$ 1,500,000	2021
	El Monte - Eden 46kV (2.5 miles)	Transmission	Ogden UT		$ 1,440,000	2021
	North Bench - Northeast 46kV (2.5 miles)	Transmission	Salt Lake UT		$ 1,200,000	2021
	Northeast - Medical 46kV (1 miles)	Transmission	Salt Lake UT		$ 480,000	2021
	Medical - Research 46kV (1 miles)	Transmission	Salt Lake UT		$ 480,000	2021
	Total Transmission system hardening			$ 35,000	$ 20,475,000	
Advanced Protection and Control	Merlin 5R232 5R251 5R234Relay	Oregon Distribution	Grants Pass	$ 223,649		2019
	Park Street 5R114 Relay Upgrade - Prelim	Oregon Distribution	Grants Pass	$ 74,968		
	CAVE JUNCTION 3R245 RLY Design	Oregon Distribution	Grants Pass	$ 59,779		
	4L50-FIOLI RECL0943 REPLC-GREAT MEADOW	Oregon Distribution	Klamath Falls	$ 30,221		2019
	OKN-5R55-DU1-9044 HWY 66-RPLC RECLOSURE	Oregon Distribution	Medford	$ 44,641		2019
	DOB-4R35-DU1-MEADOWS/DODGE-RPL RECLOSURE	Oregon Distribution	Medford	$ 24,741		2019
	New O'Brien Recloser	Oregon Distribution	Grants Pass		$ 45,000	2020
	Oak Knoll Recloser	Oregon Distribution	Medford		$ 45,000	2020
	Prospect Central Recloser	Oregon Distribution	Medford		$ 45,000	2020
	Dodge Bridge Recloser	Oregon Distribution	Medford		$ 90,000	2020
	Cave Junction Recloser	Oregon Distribution	Grants Pass		$ 45,000	2020
	Easy Valley Recloser	Oregon Distribution	Grants Pass		$ 45,000	2020
	Fielder Creek Recloser	Oregon Distribution	Grants Pass		$ 90,000	2020
	Jerome Prairie Recloser	Oregon Distribution	Grants Pass		$ 90,000	2020
	Merlin Recloser	Oregon Distribution	Grants Pass		$ 90,000	2020
	Replace DPU relay with SEL 751 w/HIFD	Oregon Distribution	Hood River		$ 65,000	2020
	Replace DPU relay with SEL 751 w/HIFD and Add DFA	Oregon Distribution	Hood River		$ 130,000	2020
	Replace DPU relay with SEL 751 w/HIFD	Oregon Distribution	Hood River		$ 65,000	2020
	Replace DPU relay with SEL 751 w/HIFD	Oregon Distribution	Hood River		$ 65,000	2020
	Replace DPU relay with SEL 751 w/HIFD and Add DFA	Oregon Distribution	Hood River		$ 130,000	2020
	Replace CB and relay with SEL 751 w/HIFD and Add DFA	Oregon Distribution	Roseburg		$ 145,000	2021
	Replace CB and relay with SEL 751 w/HIFD	Oregon Distribution	Roseburg		$ 125,000	2021
	Replace CB and relay with SEL 751 w/HIFD	Oregon Distribution	Roseburg		$ 65,000	2021
	Replace DPU relay with SEL 751 w/HIFD and Add DFA	Oregon Distribution	Grants Pass		$ 145,000	2021
	Replace DPU relay with SEL 751 w/HIFD and Add DFA	Oregon Distribution	Grants Pass		$ 125,000	2021
	Replace CB and Add HIFD to SEL 751 and Add DFA	Oregon Distribution	Medford		$ 145,000	2021

Mitigation Program	Description	Cateogry	Location	2019 Capital Costs	2020 Capital Costs	Actual or Current Estimated In-Service Date
	Replace 5R65 Relay with SEL 751 w/HIFD	Oregon Distribution	Grants Pass		$ 125,000	2021
	Replace 4R9 Relays with SEL 751 and Add DFA	Oregon Distribution	Medford		$ 145,000	2021
	Replace DPU relay and Add DFA	Oregon Distribution	Grants Pass		$ 125,000	2021
	Replace CB 5R63 and add HIFD to SEL 751 and Add DFA and replace TPU2000R w/SEL 387.	Oregon Distribution	Grants Pass		$ 145,000	2021
	Total Distribution Advanced Protection and Control			$ 458,000	$ 2,330,000	
Advanced Protection and Control	Fort Jones Substation	Transmission	Yreka CA	$126,019		2019
	CAVE JUNCTION 3R245 RLY Design	Transmission	Yreka CA	$89,779		2019
	COPCO 230kV Sub Add SCADA Cntrl Design	Transmission	Yreka CA	$55,456		2019
	COPCO 2 Replace 3G200 Relays Design	Transmission	Yreka CA	$163,492		2019
	MOTT SW Replace 3G232 Relays Design	Transmission	Yreka CA	$135,183		2019
	WEED JUNCTION Replace 3G219 Relys Design	Transmission	Weed CA	$100,225		2019
	WEED JUNCTION Replace 3G223 Relys Design	Transmission	Weed CA	$517,214		2019
	Weed Sub Add SCADA Revise Logic 2G15	Transmission	Weed CA	$120,633		2019
	Cave Junction - Happy Camp	Transmission	Grants Pass OR		$350,000	2020
	Mott - McCloud	Transmission	Yreka CA		$75,000	2020
	Copco 2 - Weed Junction	Transmission	Yreka CA		$150,000	2020
	Alturas - Newell	Transmission	Klamath CA CA		$245,000	2020
	Copco 230 - Weed Jnct	Transmission	Yreka CA		$146,000	2020
	Copco 2 - MacDoel	Transmission	Yreka CA		$188,000	2021
	Park City Stage 1: Park City - Snyderville 46kV (Park City CB 47)	Transmission	Park City UT		$224,000	2020
	Park City Stage 2: Park City - Silver Creek 46kV (Park City CB 46, Silver Creek CB 45)	Transmission	Park City UT		$448,000	2020
	Judge Stage 1: Midway-Judge 46kV (Midway CB 45, Judge CB 44)	Transmission	Park City UT		$448,000	2020
	Judge Stage 2: Judge – Brighton 46kV (Judge CB 42)	Transmission	Park City UT		$224,000	2020
	Park City-Judge 46kV (Park City CB 44, Judge CB 41)	Transmission	Park City UT		$448,000	2020
	Silver Creek - Oakley 46kV (Silver Creek 42)	Transmission	Park City UT		$224,000	2020
	Silver Creek - Kamas 46kV (Silver Creek 44)	Transmission	Park City UT		$224,000	2020
	El Monte-Eden 46kV (El Monte CB 53)	Transmission	Ogden UT		$224,000	2020
	Capitol CB 42 to North Bench CB 41	Transmission	Salt Lake UT		$450,000	2021
	North Bench CB 42	Transmission	Salt Lake UT		$225,000	2021
	Medical CB 41	Transmission	Salt Lake UT		$225,000	2021
	McClelland CB 42	Transmission	Salt Lake UT		$225,000	2021
				$1,308,000	$4,743,000	
	Total Transmission Advanced Protection and Control			$ 1,308,000	$ 4,743,000	
Condition Corrections	Priority A / B Fire Threat conditions in FHCA	Transmission	Various UT	$ 200,000		2019
					$ 100,000	2020
	Total Transmission conditions corrections			$ 200,000	$ 100,000	
Access Roads and Rights-of-way increases	Access roads and rights-of-way for transmission lines that traverse FHCA	Transmission	Park City / Cedar City UT		$ 1,000,000	2021
	Total Transmission access roads and rights-of-way increases			$ -	$ 1,000,000	
	Total			$ 2,551,000	$ 42,012,000	

CASE: UE 374
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2702

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

UE 374/PacifiCorp
July 7, 2020
OPUC Data Request 677

OPUC Data Request 677

Wildfire Mitigation
Referring to Staff/600, Moore/10, when does PacifiCorp project it will have Vegetation Clearance Violations below 100 for a calendar year? Please explain.

Response to OPUC Data Request 677

PacifiCorp objects to this data request on the grounds that, as phrased, it is argumentative and assumes violations which have not been demonstrated in fact. Without waiving the foregoing objection, PacifiCorp responds instead to the question "How does PacifiCorp intend to improve its vegetation management program in the future?" as follows:

It is PacifiCorp's intention to dramatically decrease the vegetation clearance violations over a three-year period (2021-2023). This timeframe is selected based on the program enhancements laid out in David Lucas' Testimony (Lucas/18) and their implementation timeline overlapping the existing circuit-specific cycle and interim based scheduled pruning. Key aspects of the program enhancements include; increased local supervision of vegetation management, implementation of work management software and vegetation analytics. The results over this period will be evaluated and adjustments made to achieve the desired outcome.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

OPUC Data Request 691

Wildfire Mitigation
Despite plans to increase spending and improve its vegetation management program, does PAC expect that it will be unable to maintain required clearances from electrical conductors such that the installation of covered conductors is prudent to mitigate wildfire risk by the end of 2021? Does PAC believe that they will be able to effectively maintain statutorily required vegetation clearances? If yes, by what date?

Response to OPUC Data Request 691

PacifiCorp's prudent usage of covered conductor to reduce the risk of wildfire from external line contacts (whether from vegetation or other blow-in / fall-in risks) is independent, and in addition to, the line clearances maintained by the vegetation management program. PacifiCorp is not decreasing the specification for vegetation clearances to electrical conductors in areas where covered conductor is in use. As to the second question, yes. As to the third question, please see PacifiCorp's response to OPUC Data Request 677 for further information.

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UE 374/PacifiCorp
June 16, 2020
OPUC Data Request 611

OPUC Data Request 611

Please provide the total amount of vegetation management expense that PacifiCorp has included in this filing. If these expenses are included in more than one FERC account, please provide a breakdown of the total expenses by FERC account.

Response to OPUC Data Request 611

Vegetation management expense included in PacifiCorp's filing represents actual expenses for the 12 months ended June 2019 with escalation for inflation. Amounts included is summarized as follows:

	FERC	Allocation	Total Company	Oregon-Allocated
Transmission	571	SG	4,872,661	1,267,995
Distribution	593	Situs	19,255,787	19,255,787

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UE 374/PacifiCorp
July 7, 2020
OPUC Data Request 678

OPUC Data Request 678

Wildfire Mitigation
Referring to PAC/2000, Wilding/46, and PAC/3100, McCoy/26, please provide a 2021 Test Year amount PacifiCorp projects to be included in revenue requirements for Wildfire Mitigation (if any) and Vegetation Management. Please provide a breakdown between capital, from prior years including 2020, and expense, between Vegetation Management versus Wildfire Mitigation, and amounts situs versus Oregon-allocated.

Response to OPUC Data Request 678

In the current filing, the 2021 Test Year amount of Vegetation Management and Wildfire Mitigation expenses is calculated as the escalated base period expenses from 12 months ended June 2019, plus any incremental expenses added in through Adjustment 4.7_R included in Exhibit PAC/3102. Please refer to Attachment OPUC 678, tab labelled "Expenses," for a summary of base period and test period vegetation management and wildfire mitigation expenses included in this case.

Please refer to "Capital" tab of Attachment OPUC 678 for the capital breakdown requested. There are no vegetation management capital costs in this filing. All capital amounts provided in this tab of the attachment are wildfire mitigation related. Amounts with 2021 projected in-service dates were originally included in the Company's general rate case filing with a 2020 projected in-service date and will be removed in the surrebuttal filing.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

Wildfire Mitigation Capital Expenditure by Actual or Expected In-service Date

	Total Company ($000)			Oregon-Allocated ($000)		
	2019	2020	2021	2019	2020	2021
Distribution	1,008	14,404	1,290	1,008	14,404	1,290
Transmission	1,508	10,965	15,288	392	2,853	3,978
Total	***2,516***	***25,369***	***16,578***	***1,400***	***17,257***	***5,268***

Base Period Expenses

	Total Company ($000)			Oregon-Allocated ($000)		
	Total Vegetation Management - Base Period	Vegetation-related Wildfire Mitigation[1]	Non-Vegetation Wildfilre Mitigation	Total Vegetation Management - Base Period	Vegetation-related Wildfire Mitigation[2,3]	Non-Vegetation Wildfilre Mitigation[3]
	(A)	(B)	(C)	(D)	(E)	(F)
Distribution	18,445	59	89	18,445	59	89
Transmission	4,673	318	76	1,216	83	20

Notes:

1. *Column (B) amount is a subset of totals reflected in Column (A).*
2. *Column (E) amount is a subset of totals reflected in Column (D).*
3. *Wildfire mitigation expenses is the company's best approximation as wildfire mitigation expense tracking only started in 2019, and is somewhat comingled with non-wildfire costs of the same type.*

Test Period Incremental Expenses

	Total Company ($000)			Oregon-Allocated ($000)		
	Vegetation Management	Wildfire Mitigation	McCoy Exhibit Reference	Vegetation Management	Wildfire Mitigation	McCoy Exhibit Reference
Distribution	8,599	4,780	*PAC/3104_CONF*	8,599	4,780	*PAC/3104_CONF*
Transmission	620	90	*PAC/3104_CONF*	161	23	*PAC/3104_CONF*

Allocation Factors	
SG	26.023%

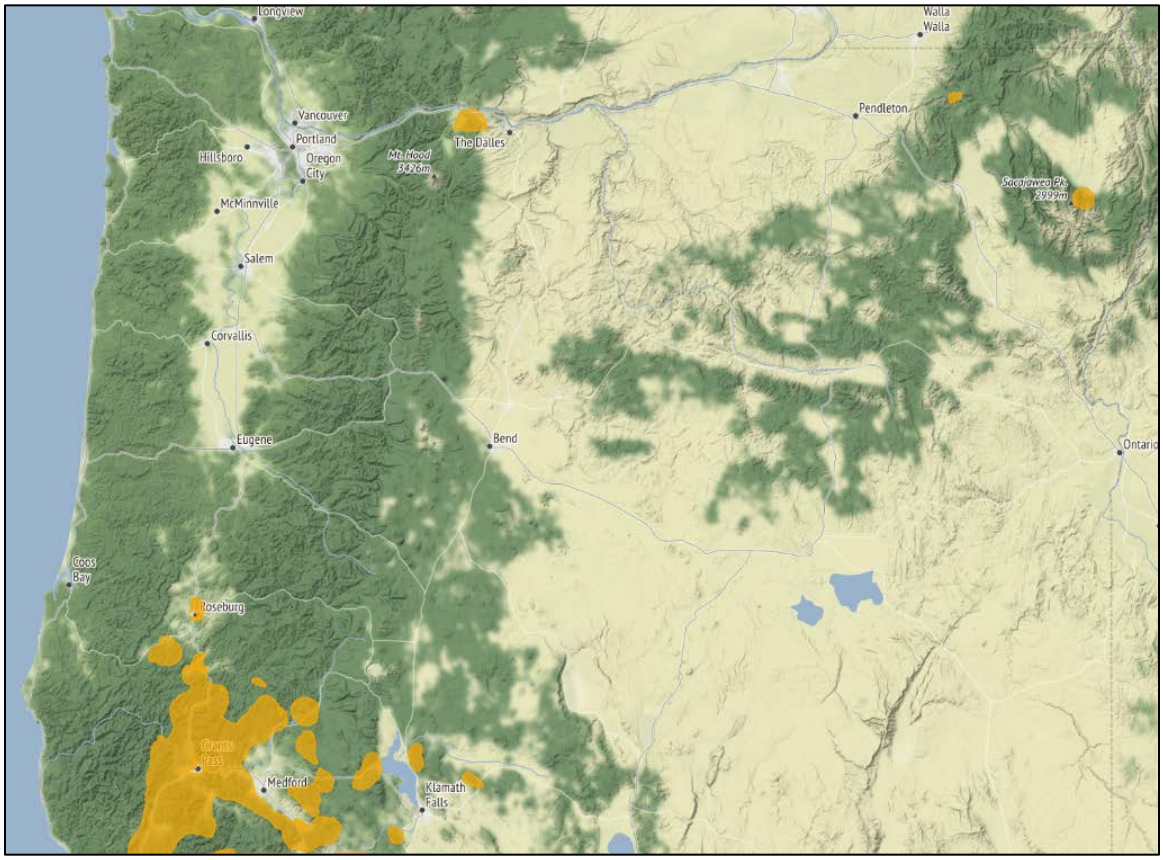
UE 374/PacifiCorp
May 18, 2020
OPUC Data Request 443

OPUC Data Request 443

Wildfire Mitigation
Please provide a system map that identifies specifically the Oregon facilities targeted for replacement, or other capital investments.

Response to OPUC Data Request 443

The Oregon wildfire mitigation work is a multi-year program that is just beginning. Therefore the full facility point details is not specified at this time. However, the Oregon map below has the areas highlighted where these replacement activities are occurring.



All Wildfire Mitigation Work is targeted in
Fire High Consequence Areas (FHCA) highlighted in Orange

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OPUC Data Request 516

Wildfire Mitigation
Referencing PAC/1100, Lucas/6, Table 1 describe in detail the ability to track fault locations with advanced protection and control micro-processor relays and covered conductors vs. bare conductors.

Response to OPUC Data Request 516

Micro-processor relays collect substantial signal data that allows for algorithms to be run which, at minimum, provide fault records (magnitude of fault current, specific phases that experienced the fault, the time and date of the fault, and based upon line topology details, i.e. line impedances, the location of the fault, with estimated accuracy). In addition, many of these relays retain substantial event data for periodic interrogation when operational investigations are appropriate. They also record wave forms and certain of these devices may have more sophisticated fault detection (such as traveling wave which uses wave reflection to more precisely detect where faults originated). These relays are also capable of much more precise dialing-in of fault responses, such that there is a much narrower amount of time that coordinating devices may be out of sync with these devices. Finally, additional functionality, such as high impedance fault detection and "wire down" technology, in addition to wave form signature analysis will be viable with these devices in the future, all of which are in development. These devices are targeted toward the strategy of "when a fault occurs on the network, detect the fault and as precisely and rapidly reduce the arc energy to which the network is exposed." which will reduce the probability of utility ignition.

Covered conductor replacing bare conductor is designed to eliminate incidental contact which could lead to an ignition. So, whether associated with birds flying into a line, lightning striking a line, or a wind-borne branch coming into contact with an electric line, the covered conductor is resilient and no electrical fault will occur as a result of such contact. This mitigation supports the strategy of "being resilient to events that could result in a fault event."

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OPUC Data Request 517

Wildfire Mitigation
Referencing PAC/1100, Lucas/7, lines 17-21, identify the Oregon FHCA locations and describe distribution voltages where covered conductors will be utilized.

Provide the phase to ground and phase to phase insulation level of the covered conductors. Describe in detail how energized wire down on the ground situations identified in line 21 will be identified and mitigated with advanced protection and control relaying schemes.

Response to OPUC Data Request 517

PacifiCorp is generally targeting replacement of Fire High Consequences Area (FHCA) distribution conductors that range in voltage from 20.8 kilovolts (kV) down to 4 kV. Spacer cable, which is the intended covered conductor installation method, uses weak-link design processes in which the system is engineered to minimize the risk of brittle failure, such as would occur when a pole would be damaged and fail catastrophically. The system is engineered to have the bracket attaching the messenger bundle to the pole to be the first to break, followed by the messenger, followed by the pole. While the bracket is first to fail, post-hurricane Sandy improvements in a hardened "flex" bracket have yielded substantial strength improvements such that the probability of failure is reduced substantially. In the event of damage, the Company is evaluating whether communication technologies could be used to convey such issues. As a standard matter of practice, the Company is employing high impedance fault detection as part of its new standard for detecting anomalies.

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OPUC Data Request 521

Wildfire Mitigation
Referencing PAC/1100, Lucas/14, beginning at line 8, describe in detail the benefit of micro-processor based relays without SCADA and the increased ability to locate where a fault occurs and improvements in patrol and restoration times.

Response to OPUC Data Request 521

Please see the Company's response to OPUC Data Request 516.

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UE 374/PacifiCorp
June 16, 2020
OPUC Data Request 601

OPUC Data Request 601

How many miles of transmission and distribution, stated separately, in Oregon, does PAC contemplate replacing energized conductors?

Response to OPUC Data Request 601

PacifiCorp plans on replacing 961 miles of distribution circuit in Oregon by 2023 with a total of 2,038 miles by 2026. There is currently no plan to replace transmission energized conductor.

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UE 374/PacifiCorp
June 16, 2020
OPUC Data Request 602

OPUC Data Request 602

Please describe in detail PacifiCorp's plan to replace energized conductors in California, Washington, Idaho, Wyoming and Utah.

Response to OPUC Data Request 602

Transmission lines located inside of the Fire High Consequence Area will be considered for rebuild based on the modeled wildfire risk, age and condition of the assets. PacifiCorp plans on replacing 164 miles of distribution in California by 2023 and 23 miles of transmission by 2023. Additionally, 12 miles of distribution in Washington will be replaced by 2023. PacifiCorp plans on replacing 82 miles of transmission in Utah by 2023 with a total of 111 miles by 2026. There are no lines in Washington, Idaho, and Wyoming scheduled to be rebuilt as part of the Wildland Fire Protection Plan.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

OPUC Data Request 686

Wildfire Mitigation
Referring to PAC/2900, Lucas/6, lines 22-23: please identify and describe in detail the specific capital projects that the Company proposes to include in this case for rates going into effect beginning January 1, 2021.

Response to OPUC Data Request 686

As discussed in the Company's response to OPUC Data Request 612, the Company proposed to include the projects listed in Attachment OPUC 612 for inclusion in rates going into effect beginning January 1, 2021. However, since the Company's original rate case filing, some of the project dates have been adjusted and are now expected to go into service in 2021. Those projects with 2021 in-service dates will be removed from the Company's revenue requirement in its surrebuttal filing.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

UE 374/PacifiCorp
May 18, 2020
OPUC Data Request 438

OPUC Data Request 438

Wildfire Mitigation
Referencing PAC/1100, Lucas/6, lines 1-2, has PacifiCorp performed any risk/benefit analysis to determine the level of risk that will be eliminated from the system upon completion of the transmission and distribution rebuilds, as a function of cost?

Response to OPUC Data Request 438

The Company has not yet developed a risk/benefit analysis supporting specific prioritization of locations for mitigation efforts that would optimize their risk/benefit. Generally, the Company has developed a high-level strategy and has contemplated the impacts of potential Public Safety Power Shutoff actions on customers as the primary method for prioritizing investments. However, at this time the Company is evaluating methods to develop program level estimates on the reduction of utility ignition risks, which it will be advancing in the future.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

UE 374/PacifiCorp
May 18, 2020
OPUC Data Request 439

OPUC Data Request 439

Wildfire Mitigation
Referencing PAC/1100, Lucas/10, lines 9-22 and Lucas/11, lines 1-2: Can PacifiCorp provide any data or studies performed by other jurisdictions, or other agencies, or analysts that demonstrate the effectiveness and the cost prudence of the system-hardening activities proposed? If yes, please provide.

Response to OPUC Data Request 439

PacifiCorp has no specific data or studies performed by other jurisdictions, agencies, or analysts that demonstrate the effectiveness and the cost prudence of the system-hardening activities proposed. While the measures identified for system hardening have been contemplated because of their impact to utility ignition risk reduction, the Company has substantial history demonstrating the effectiveness of these measures on reducing utility fault events, as measured by outages and impact to customers. The Company leveraged that experience and understanding of improvement factors in devising its hardening activities.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

OPUC Data Request 687

Wildfire Mitigation
Referring to PAC/2902, slide 3: please provide any efficacy studies and mitigation results that have been documented by all of the jurisdictions cited in the exhibit that have employed covered conductors. Provide all information in this regard that PAC is aware of, for example, efficacy studies/mitigation results from Scandinavia, the United Kingdom, New England, Tokyo, Thailand, Malaysia, etc.

Response to OPUC Data Request 687

PacifiCorp is not aware of any cost efficacy studies for the various locations in which covered conductor is installed.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

OPUC Data Request 688

Wildfire Mitigation
Referring to PAC/2902, slide 3: please provide all cost-benefit analyses that PAC is aware of that have been performed on the installation of covered conductors in the jurisdictions cited in this slide.

Response to OPUC Data Request 688

PacifiCorp has limited experience with the efficacy of covered conductors, but is aware of the following documents from Southern California Edison Company (SCE) that are related to the referenced exhibit. Please refer to Attachment OPUC 688-1 for SCE's 2018 Risk Assessment and Mitigation Phase Report, dated November 15, 2018. Chapters 1, 2, 10 and 12 provide cost/benefit analysis as supported with SCE's risk spend efficiency, which is summarized on slide 3 of PAC/2902.

Refer to the following attachments for additional documents supporting SCE's presentation:

- Attachment OPUC 688-2—Prepared Testimony in Support of SCE's Application for Approval of its Grid Safety and Resiliency Program, dated September 18, 2018,
- Attachment OPUC 688-3—SCE's 2021 General Rate Case Amended Testimony on Wildfire Management, dated November 22, 2019,
- Attachment OPUC 688-4—SCE's 2021 General Rate Case Rebuttal Testimony on Wildfire Management, dated June 12, 2020, and
- Attachment OPUC 688-5—SCE's 2020-2022 Wildfire Mitigation Plan.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

OPUC Data Request 692

Wildfire Mitigation
Please explain remaining wildfire risk, if any, if PacifiCorp meets vegetation clearances from its electrical facilities, and timely repairs damaged equipment and lines, in accordance with applicable legal requirements.

Response to OPUC Data Request 692

The vast majority of wildfire risk has little to do with non-wind clearances from conductor, but is associated with wind-borne impacts to vegetation on and off right-of way or other "contact from object" risks. Mr. Lucas outlines several aspects to this ongoing wildfire risk in his reply testimony.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

CASE: UE 374
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2703

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Investigation Into the November 2018 Submission of Southern California Edison's Risk Assessment and Mitigation Phase.	I.18-11-006

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) 2018 RISK ASSESSMENT AND MITIGATION PHASE REPORT

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Dated: November 15, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E)
2018 RISK ASSESSMENT AND MITIGATION PHASE REPORT

I.

INTRODUCTION

Pursuant to California Public Utilities Commission (Commission) Decisions (D.) 14-12-025 and 16-08-018, and the Commission's Rules of Practice and Procedure, Southern California Edison Company (SCE) respectfully submits its 2018 Risk Assessment Mitigation Phase (RAMP) Report (Report).

This RAMP report marks a significant milestone in the progress of SCE's risk-informed decision-making framework, consistent with the evolution of the framework that has been developing in the Safety Model Assessment Proceeding (S-MAP).[1] In the course of developing its RAMP report, SCE met with stakeholders on a number of occasions to discuss SCE's approach to RAMP and to solicit feedback.[2] SCE very much appreciates the feedback it has received from these stakeholders, and has included certain feedback as applicable in this report.

[1] A.15-05-005.
[2] These stakeholders included: the Commission's Safety & Enforcement Division (SED), Office of the Safety Advocate (OSA), Public Advocates Office, Energy Division, and The Utility Reform Network (TURN).

For example, as a result of stakeholder feedback, SCE has included appendices to its RAMP report that specifically address Nuclear Decommissioning, Transmission and Substation Assets, and Seismic Events.

II.

SUBSTANCE OF SCE'S RAMP REPORT

SCE's RAMP report examines the top safety risks to SCE's customers and the communities that SCE is privileged to serve, to SCE, and to SCE's employees and contractors. After thorough analysis and evaluation, SCE identified these nine top safety risks that warranted inclusion in this report: *Building Safety; Contact With Energized Equipment; Cyber Attack; Employee, Contractor, and Public Safety; Hydro Asset Safety; Physical Security; Wildfire; Underground Equipment Failure; and Climate Change*.

Each of these nine risks is explained and assessed in detail in the individual chapters of SCE's RAMP report. SCE carefully analyzes existing controls, and identifies new mitigations that can and will help address these risks. For each mitigation plan, SCE also presents two separate alternative mitigation plans that were considered. SCE outlines why it selected the mitigation plan it proposes.

SCE also deployed a new multi-attribute probabilistic risk evaluation model to evaluate the risks and the effectiveness of their associated controls and mitigations. In developing its report, SCE tested several new risk modeling parameters that collectively should advance and illustrate many aspects of the S-MAP Settlement Agreement (Settlement).[3] This is SCE's first-generation probabilistic risk evaluation model for use in RAMP, and SCE expects to refine the model in future RAMP reports.

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[3] A.15-05-005, Joint Motion For Approval Of Settlement Agreement Plus Request For Receipt Into The Record Of Previously Served Documents And For Expedited Comment Period Of Pacific Gas And Electric Company (U-39 E), Southern California Edison Company (U-338 E), Southern California Gas Company (U-904 G), San Diego Gas & Electric Company (U-902 M), The Office Of Ratepayer Advocates, The Utility Reform Network, And Energy Producers And Users Coalition And Indicated Shippers; May 2, 2018.

Lastly, SCE candidly discusses lessons learned, and identifies opportunities for improvement in future RAMP reports.

III.

ROADMAP OF SCE'S RAMP REPORT

SCE's Report is organized in chapters as follows:

Chapter	Title
1	RAMP Report Overview
2	Risk Model Overview
3	Safety Culture & Compensation Policies tied to Safety
4	Building Safety
5	Contact with Energized Equipment
6	Cyberattack
7	Employee, Contractor & Public Safety
8	Hydro Asset Safety
9	Physical Security
10	Wildfire
11	Underground Equipment Failure
12	Climate Change
Appendix A	Nuclear Decommissioning
Appendix B	Transmission & Substation Assets
Appendix C	Seismic Events

IV.

CONCLUSION

SCE's RAMP report represents a significant step forward in how SCE thinks about, plans for, and mitigates the most critical safety risks. This report will inform the safety-related funding

requests that SCE will include in its Test Year 2021 General Rate Case (GRC), scheduled to be filed in September 2019.

Respectfully submitted,

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November 15, 2018

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

(U 338-E)

I.18-11-006

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Rosemead CA
November 15, 2018

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2 Risk Model Overview

3 Safety Culture & Compensation Policies tied to Safety

4 Building Safety

5 Contact with Energized Equipment

6 Cyberattack

7 Employee, Contractor & Public Safety

8 Hydro Asset Safety

9 Physical Security

10 Wildfire

11 Underground Equipment Failure

12 Climate Change

Appendix A Nuclear Decommissioning

Appendix B Transmission & Substation Assets

Appendix C Seismic Events

SOUTHERN CALIFORNIA EDISON®
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Southern California Edison Company's

Risk Assessment and Mitigation Phase

RAMP Overview

Chapter 1

Rosemead CA
November 15, 2018

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I. RAMP Overview

A. Executive Summary

SCE appreciates the opportunity to present its RAMP report to the Commission and to the Parties in the RAMP Order Instituting Investigation proceeding (I.18-11-006). This RAMP report marks a significant milestone in the progress of SCE's risk-informed decision-making framework, consistent with the evolution of the framework that has been developing in the Safety Model Assessment Proceeding (S-MAP). In preparing this report, we obtained information and support from the majority of organizational units within SCE. We also incorporated feedback we obtained through informal and collaborative discussions with external parties and stakeholders.[1]

Our RAMP report examines the top safety risks to our customers and the communities we are privileged to serve, to our company, and to our employees and contractors.[2] After rigorous analysis and evaluation, SCE identified these nine top safety risks that warranted inclusion in RAMP: *Building Safety; Contact With Energized Equipment; Cyber Attack; Employee, Contractor, and Public Safety; Hydro Asset Safety; Physical Security; Wildfire; Underground Equipment Failure; and Climate Change*.

Each of these nine risks is explained and assessed in detail in the individual chapters of this report. We analyze existing controls, and identify new mitigations that can and will help address these risks. For each mitigation plan, we also present two separate alternative mitigation plans that we considered. We outline why, out of the three plans, we chose the mitigation plan we have selected.

We also deployed a new multi-attribute probabilistic risk evaluation model to evaluate these risks and the effectiveness of their associated controls and mitigations. The attributes

[1] While developing this RAMP report, SCE met with stakeholders on many occasions to discuss our approach to RAMP and solicit feedback. These stakeholders included: the Commission's Safety & Enforcement Division (SED), Office of the Safety Advocate (OSA), Public Advocates Office, Energy Division, and The Utility Reform Network (TURN). We very much appreciate the feedback we received from these stakeholders, and we have included certain feedback as applicable in this report.
[2] Throughout this report, SCE collectively refers to our employees and contractors as "workers."

examined include serious injury, fatality, reliability, and financial. In developing our report, SCE tested several new risk modeling parameters that collectively will advance and illustrate many aspects of the S-MAP Settlement Agreement (Settlement).[3,4] This is SCE's first-generation probabilistic risk evaluation model for use in RAMP, and we expect to refine the model in future RAMP reports.

Finally, we candidly discuss lessons learned, and improvement opportunities for future RAMP reports.

In sum, the RAMP report represents a significant step forward in how we think about, plan for, and mitigate our top safety risks. It will inform the safety-related funding requests that we will include in our Test Year 2021 General Rate Case (GRC), scheduled to be filed by September 3, 2019.

B. Procedural Background

On November 14, 2013, the Commission issued an Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the Rate Case Plan for Energy Utilities (R.13-11-006, or Risk OIR). The Risk OIR sought to incorporate a risk-based framework into the Rate Case Plan that each energy utility must follow. In the Risk OIR, the Commission instituted two new processes designed to feed into the portions of General Rate Case applications where utilities request funding for safety-related activities. These two processes are the S-MAP and the RAMP.

SCE's RAMP report originates from, and is guided by, two key Commission decisions. First, in the Risk OIR, the Commission issued D.14-12-025, which modified the Rate Case Plan to include a risk-based framework and "provide a transparent process to ensure that the energy utilities are placing the safety of the public, and of their employees, as a top priority in their respective GRC proceedings."[5] The decision indicated that each utility's RAMP report should show:

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[3] Appendix B to this chapter discusses how the report aligns with this Settlement.
[4] Joint Motion For Approval Of Settlement Agreement Plus Request For Receipt Into The Record Of Previously Served Documents And For Expedited Comment Period Of Pacific Gas And Electric Company (U-39 E), Southern California Edison Company (U-338 E), Southern California Gas Company (U-904 G), San Diego Gas & Electric Company (U-902 M), The Office Of Ratepayer Advocates, The Utility Reform Network, And Energy Producers And Users Coalition And Indicated Shippers; May 2, 2018.
[5] D.14-12-025, p. 35.

- The utility's prioritization of the risks it believes it is facing and a description of the methodology used to determine these risks.

- A description of the controls currently in place, and the "baseline" costs associated with the current controls.

- The utility's prioritization of risk mitigation alternatives, in light of estimated mitigation costs in relation to risk mitigation benefits (a Risk Mitigated to Cost Ratio).

- The utility's risk mitigation plan, including an explanation of how the plan considers: utility financial constraints; execution feasibility; affordability impacts; and any other constraints identified by the utility.

- For comparison purposes, at least two other alternative mitigation plans the utility considered and an explanation of why the utility views these plans as inferior to the proposed plan.[6]

Second, the Commission issued an interim decision in its S-MAP. That interim decision, D.16-08-018, provided certain guidelines for what should be included in the utilities' RAMP reports, including adopting the Cycla Corporation 10-step framework.[7] The decision also guided SED on what it should look for in evaluating the utilities' RAMP submissions and preparing its report on each utility's RAMP showing.

In accordance with the Commission's guidance in D.14-12-025,[8] on August 29, 2018, SCE duly requested an Order Instituting Investigation (OII) to provide a docket for filing of SCE's RAMP showing, as well as comments and feedback on that RAMP. On November 9, 2018 the Commission opened I.18-11-006.

[6] D.14-12-025, pp. 31-32.
[7] D.16-08-018, Ordering Paragraph (OP) 4.
[8] *See* D.14-12-025, p. 41, Table 3.

C. SCE's RAMP Report Meets Commission Requirements Adopted in the S-MAP Interim Decision[9]

SCE developed this report in accordance with Commission guidance,[10] and with due consideration of feedback received from various stakeholder groups.[11] Our intention is to circulate a transparent and collaborative report that advances utility risk-informed decision-making within the Commission's regulatory process. Our approach to the ten key requirements of the RAMP submission is summarized below:

1. *Requirement 1:* Identify top safety risks

SCE identified nine top safety risk areas. Each one is discussed in individual chapters of this report. Section G of this chapter describes the process we undertook to identify the top safety risks to include in RAMP.

In addition, SCE includes three appendices to this report. Two additional risk areas are addressed in Appendix A – Nuclear Decommissioning Safety Risks, and Appendix B – Transmission & Substation Safety risks. These two areas did not "rise to the top" during the process we followed to identify the top safety risks that would be specifically quantified in this RAMP report. However, after discussion with SED and further internal evaluation, SCE is qualitatively assessing these two areas as a supplement to this report.

The third appendix provides greater context regarding seismic event risk. Seismic events are a key driver to various safety risks for SCE. While major seismic events occur infrequently, such events can seriously impact our critical assets and facilities. SCE must proactively harden our critical assets and facilities to mitigate the safety, reliability, and financial consequences of these events. As will be discussed in greater detail in Section G and in Appendix C, SCE includes seismic events as a driver to both the Hydro Asset Safety and Building Safety chapters.

2. *Requirement 2:* Describe the controls or mitigations currently in place

To describe the controls currently in place, and potential new mitigations, to address each risk, SCE developed three broad groupings of activities: *(1) Compliance Controls,*

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[9] D.16-08-018.
[10] *See* D.14-12-025, D.16-08-018.
[11] As discussed above, while developing this RAMP report, SCE met with stakeholders on many occasions to discuss our approach to RAMP and solicit feedback.

(2) Controls, and (3) Mitigations. This grouping is important in establishing which activities are included in the baseline residual risk, and which activities are measured to reduce that baseline risk.

a. Compliance Controls

Compliance Controls (commonly referred to in the report with the prefix "CM") are defined as currently-established activities that modify or reduce risk, and that are required by law or regulation. To take some examples, activities that support Federal or State OSHA requirements, FERC Orders and requirements for hydro facilities, and Commission General Orders, are all considered Compliance Controls.

In most cases, SCE will include compliance activities in its baseline risk. Because SCE is required to perform these activities by law or regulation, they are foundational to operating the utility. In addition, it is often very difficult to evaluate the inherent risk that is present in the absence of these compliance activities. In each risk chapter, SCE will describe these Compliance Controls and show their recorded expenditures*, but will not evaluate the risk reduction or Risk Spend Efficiently (RSE) of the compliance activities*. Stated differently, the benefits of these compliance activities are included in the baseline risk level for each risk.

b. Controls

Existing controls (commonly referred to in the report with the prefix "C") are mitigation activities established prior to 2018 that are modifying or reducing risk, and are not required by law or regulation. Examples of existing controls include the Overhead Conductor Program, Worst Circuit Rehabilitation program, and internal training programs not associated with a compliance requirement.

In this RAMP report, SCE measures the risk reduction benefits and RSE of existing controls. Section III of each risk chapter details the Compliance Controls and Controls that are currently in place to address each risk.

c. Mitigations

Mitigations (commonly referred to in the report with the prefix "M") are defined as new activities and efforts that reduce risk, and that are not required by law or regulation. Examples of new mitigations include: (1) a new program or project that starts in 2018 or beyond that is not currently being performed; (2) a material incremental scope of work based on emergent risk; and (3) a project or program that is under construction or in the process of being implemented.

In this RAMP report, SCE measures the risk reduction benefits and RSE of new mitigations. SCE identifies and describes these risk mitigations in Section IV of each chapter.

In the workpapers that accompany this report, SCE provides an aggregate listing of the recorded and forecast costs for the proposed controls and mitigations.[12] As appropriate, SCE will refine this list of controls and mitigations in our 2021 GRC, to reflect emergent information on how best to mitigate the RAMP risks.

3. *Requirement 3:* Present a plan for improving the mitigation of each risk

In Section V of each chapter, SCE presents its proposed plan for addressing each risk. This proposed plan pulls together controls and mitigations that were identified in Sections III and IV of each chapter, to develop a preferred risk mitigation portfolio over the 2018-2023 period. We then evaluate this portfolio based on its total cost, risk reduction, risk spend efficiency, execution feasibility, technology maturity, resource constraints, and other factors.

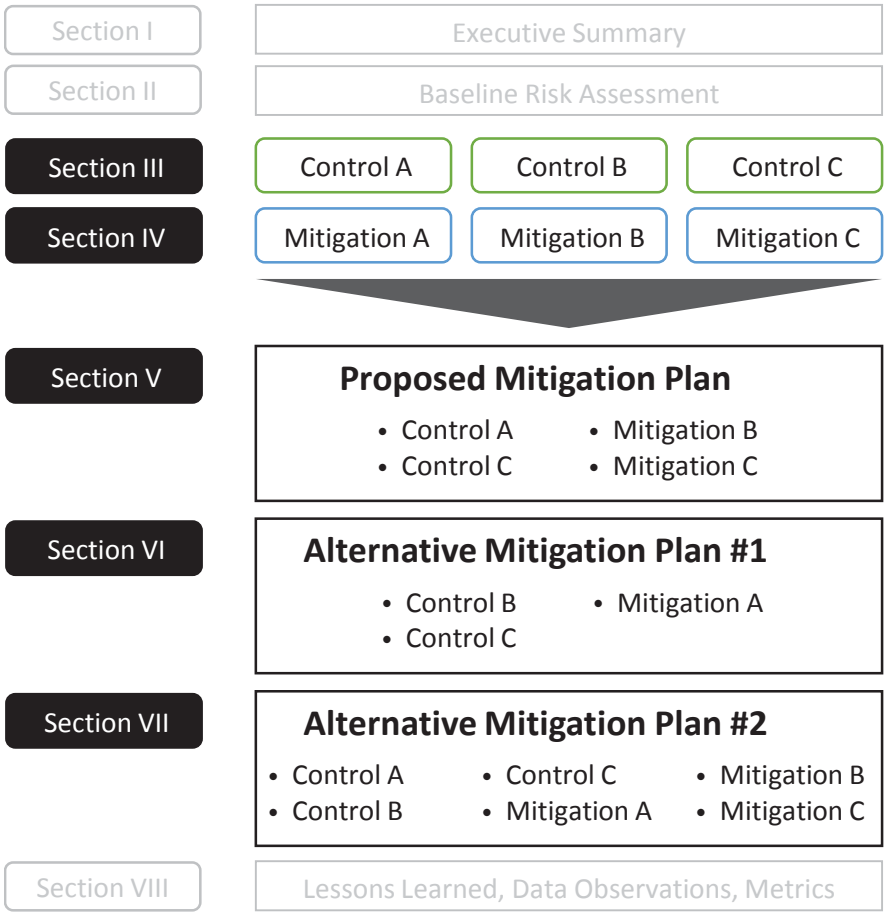
4. *Requirement 4:* Present two alternative mitigation plans that were considered

Finally, in Sections VI and VII of each chapter, SCE details two alternative mitigation portfolios for addressing each risk. Similar to the proposed mitigation portfolio, SCE builds these alternative plans by selecting various controls and mitigations identified in Sections III and IV of each chapter. We also evaluate these portfolios based on total cost, risk reduction, risk spend efficiency, execution feasibility, technology maturity, resource constraints, and other factors.

Figure I-1 illustrates the process SCE uses to identify and evaluate the proposed and alternative mitigation plans within each chapter. The steps in this process (sections II – VII of each chapters) are shown in the broader context of each chapter's structure.

[12] Please refer to WP Ch. 1, p. 1.1 *(2013 – 2023 Recorded and Forecast Costs for Controls & Mitigations)*.

Figure I-1 – Chapter Mitigation Plan Development (Illustrative)



5. *Requirement 5:* Present an early stage "risk mitigated to cost ratio"

SCE has adopted the concept of Risk Spend Efficiency (RSE), which is a measure of risk reduction per dollar spent. In its most simplistic form, the RSE calculation is:

RSE= $(Mitigation\ Risk\ Reduction)/(Mitigation\ Cost)$

SCE applies RSE to individual controls and mitigations over the RAMP period, and to each of the mitigation plans as a whole. The RSE offers us insights into how effective our existing controls appear to be in reducing risk, while providing guidance on how effective the

new mitigations may be.[13] We used the RSE as a valuable contributing metric to inform the development of our proposed and alternative portfolios within each chapter. As discussed in each risk chapter, RSE is not the only factor that SCE uses to inform the selection of proposed risk mitigation plans, but it provides directional guidance.

6. *Requirement 6:* Identify lessons learned in the current round to apply in future RAMP reports

Section VIII of each risk chapter identifies lessons learned from developing each chapter that will inform our next RAMP report.

SCE has also identified several global lessons learned across our RAMP effort. These are discussed in more detail in Section J - Global Challenges and Lessons Learned in Development of RAMP Report.

7. Requirement 7: Move toward probabilistic calculations as much as possible

This RAMP report reflects a significant step forward for SCE in using probabilistic modeling to evaluate risk. SCE respectfully believes it has built a robust probabilistic risk modeling framework to support evaluating risk, and examining the effects that risk controls and mitigation activities can have on that risk. To do this, SCE employs a Microsoft Excel-based model that leverages a risk-modeling add-in called @RISK. This model enables us to analyze risk using Monte Carlo simulations,[14] showing us the distribution of virtually all possible outcomes, and how likely they are to occur.[15] This model allows users to insert relevant input data and assumptions in a manner that best reflects the nature of each risk.

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[13] Within this RAMP report, the RSE metric is most useful for relative comparisons between controls and mitigations within a risk chapter. It is important to note that because the maximum MARS score is 100, and because our controls and mitigations cost more than $100 dollars to execute, the RSE scores are all small numbers (mostly less than one). This is purely a product of the RSE math equation, and does not indicate that actual efficiency of a mitigation is low just because the RSE is less than one. *See* Chapter II – Risk Model Overview for further discussion.

[14] Monte Carlo simulations are used to model the probability of different outcomes in a process that cannot easily be predicted due to the intervention of random variables. It is a technique used to understand the impact of risk and uncertainty in prediction and forecasting models. Monte Carlo simulation can be used to tackle a range of problems in virtually every field such as finance, engineering, supply chain, and science. Monte Carlo simulation is also referred to as probability simulation.

[15] Please refer to Appendix 2, Section A of this Chapter, and Chapter 2 (Risk Model Overview), for additional discussion on the MARS calculation framework.

8. Requirement 8: For those business areas with less data, improve the collection of data and provide a timeframe for improvement

Section VIII of each chapter identifies data limitations we identified through developing our RAMP showing, identifies opportunities to address those limitations going forward, and outlines performance metrics that will help us measure progress towards reducing the risk.

9. Requirement 9: Describe SCE's safety culture, executive engagement, and compensation policies

Chapter III of this RAMP report discusses SCE's safety culture, safety performance, and how SCE's compensation policies are tied to safety performance.

10. Requirement 10: Respond to immediate or short-term crises outside of the RAMP and GRC process

The environmental, economic, and political conditions in which we operate across our 50,000 square mile service territory are constantly evolving. As the Commission rightly recognizes, we must act expeditiously to address emergent risks that arise outside of the RAMP and GRC processes. SCE's obligation to deliver safe and reliable power requires that adjustments be made as these risks arise. SCE makes these adjustments to our operations on a daily basis to account for contingencies such as major storm events. And these adjustments can be made over a longer period of time to address resources gaps not anticipated in the prior GRC. For example, SCE filed a Grid Safety & Resiliency Program (GS&RP) application[16] in September 2018 to address the very serious and emergent wildfire risks to public and worker safety and utility operations. The magnitude of this risk was not anticipated back in 2016, when SCE was developing its showing for the 2018 GRC.

D. SCE's RAMP Report Aligns with the S-MAP Settlement Agreement

SCE's RAMP report is consistent with the S-MAP Settlement Agreement (Settlement) that SCE and several other parties submitted to the Commission on May 2, 2018. Table I-I indicates major elements of the Settlement Agreement, along with references to where that element is discussed in SCE's RAMP report. Additionally, Appendix 2 to this chapter provides a more in-depth review of the alignment between SCE's RAMP Report and the Settlement

[16] A.18-09-002.

Agreement. On November 9th, a Proposed Decision was issued adopting the Settlement Agreement.

Table I-I – Alignment of SCE RAMP Report with SMAP Settlement Agreement

Major Elements of the Settlement Agreement	Associated Section of the Settlement Agreement	SCE RAMP Report Sections that Explain SCE's Approach (in addition to Appendix B)
Use of a Multi-Attribute Value Framework (MAVF)	1A	Chapter I, Section I.D.7
Enterprise Risk Register (ERR) as the Starting Point for RAMP Risk Selection	1B, 2A, 2B	Chapter I, Sections I.D.1, I.F.1-5, and I.G
Use of the Bowtie Diagram	3	Chapter 1, Section I.C.1
Mitigations Linked to Drivers and/or Outcomes	3	Chapter III
Measurement of Risk Reduction and Calculation of Risk Spend Efficiency (RSE)	3	Chapter III

E. Corporate Governance of Risk Management

Company senior leadership heavily engages with and manages the enterprise risks at SCE. Enhancements and changes to the risk-informed decision-making framework are regularly communicated to senior leadership, and they actively provide guidance and feedback.

Throughout the year, the Enterprise Risk Management (ERM) group meets with senior leaders to review and discuss enterprise-level risks and mitigation plans. SCE senior leadership plays a critical role in establishing a strong risk assessment culture across the company by actively engaging with enterprise risk management efforts, by encouraging leaders and subject matter experts (SMEs) throughout the Company to participate in the process, and by making this effort one of the company-wide continuous improvement priorities. This support has enabled the ERM group to develop, establish, and implement a more consistent and structured risk-informed decision-making framework.

SCE has a Finance and Risk Management (FRM) Committee, chaired by the SCE Chief Financial Officer (CFO), and consisting of the SCE General Counsel and the Senior Vice President (SVP) of Regulatory Affairs as voting members. The SCE Chief Executive Officer (CEO) and

President are also active participants in FRM Committee meetings; the CEO is required to vote only on matters exceeding certain cost or impact thresholds. The purpose of this committee is to: (1) oversee and approve the allocation of SCE's financial resources, energy procurement activities, and enterprise-wide risk management; and (2) provide a forum and a process to identify, understand, manage and mitigate critical risks related to these areas, in accordance with California Public Utilities Commission (CPUC) directives and company policies.[17]

The leadership team at SCE's parent company, Edison International (EIX), has established a Risk Management Committee (EIX RMC) that oversees SCE's risk management program and enterprise risks. The EIX RMC is chaired by the EIX CFO, and includes as members the EIX CEO, EIX General Counsel, EIX SVP of Strategy and Corporate Development, and the EIX Vice President of Enterprise Risk Management & Insurance and General Auditor ("EIX VP of Risk Management") as a participant. The SCE CEO, CFO, and General Counsel also participate in matters involving SCE risks.

The EIX RMC is responsible for reviewing and understanding critical risks facing SCE. The EIX RMC reviews and approves the annual enterprise risk assessment and mitigation plans. EIX leadership is also responsible for encouraging a corporate-wide culture that makes identifying, managing, mitigating, and reporting risks an integral part of corporate strategy and operations.

Through these various executive committees and forums, oversight of SCE's enterprise risk management program is provided at all levels of the Company. ERM oversight includes:

- EIX and SCE Board of Directors, Board of Directors Audit Committee, and EIX RMC;
- SCE senior management including the SCE CEO, President, CFO, the General Counsel, and FRM Committee;
- EIX VP of Enterprise Risk Management who reports to EIX CFO;
- SCE senior leaders managing OU risks across the Company;
- SCE's Director of Risk Management who reports to the SCE CFO and EIX VP of Risk Management;
- SCE's Principal Manager of ERM who reports to SCE's Director of Risk Management; and
- Risk Advisors and Senior Advisors who report to SCE's Principal Manager of ERM.

[17] The FRM Committee addresses issues related to: capital allocation and investment decisions; annual budgets, operating plans, and long-term financial forecasts; energy procurement; non-energy procurement; executive oversight of compliance issues; executive oversight of business resiliency issues; SCE cybersecurity; and enterprise-level risks and mitigation plans.

Lastly, SCE must be prepared to respond to risk events if they materialize. SCE has developed a strategic approach to minimize the impacts of business disruption by better understanding these threats and fully engaging all areas of the company to develop integrated solutions for responding. These solutions can encompass internal and external stakeholders. For example:

- SCE Incident Management Program – SCE established an incident management structure compliant with guidelines issued by the National Incident Management System (NIMS) and Federal Emergency Management Agency (FEMA) Incident Command System (ICS). The management structure is built around Incident Management Teams (IMTs). An IMT is a group of trained and qualified personnel from different SCE organizational units called upon to lead a response to an emergency or incident.

- Business Impact Analysis – SCE conducts cross-company efforts to determine and prioritize our most mission-critical functions and applications. SCE also maintains business continuity plans and disaster recovery procedures that guide our recovery efforts following any business disruption.

- Emergency Operations Center – SCE has established a dedicated center for detecting, managing, and monitoring emergency events. This includes a situational awareness center to capture weather patterns and analysis, a mobile command center, and a 24x7 Watch Office that monitors our service territory, disseminates important information, and notifies on-call IMTs when needed.

- Coordination with External Stakeholders – SCE performs extensive outreach and coordinated efforts with local, state, and federal agencies, as well as other critical lifeline utilities (gas, water, telecommunications, CalTrans, etc.). This helps ensure we are as prepared as possible for the variety of risk events that could occur in our service territory.

Many of these actions are discussed in more detail in Chapter 12 (Climate Change).

F. Overview of SCE's Risk-Informed Decision-Making Framework Used in RAMP

The process of developing this RAMP report has enhanced SCE's risk-informed decision-making framework. This framework enables the company to identify, evaluate, mitigate, and monitor risks and to report on the risks to the company's senior leadership. This framework also lets us explicitly include risk considerations in SCE's decision-making process. Senior leadership employs the framework to review, discuss, prioritize, monitor, and address

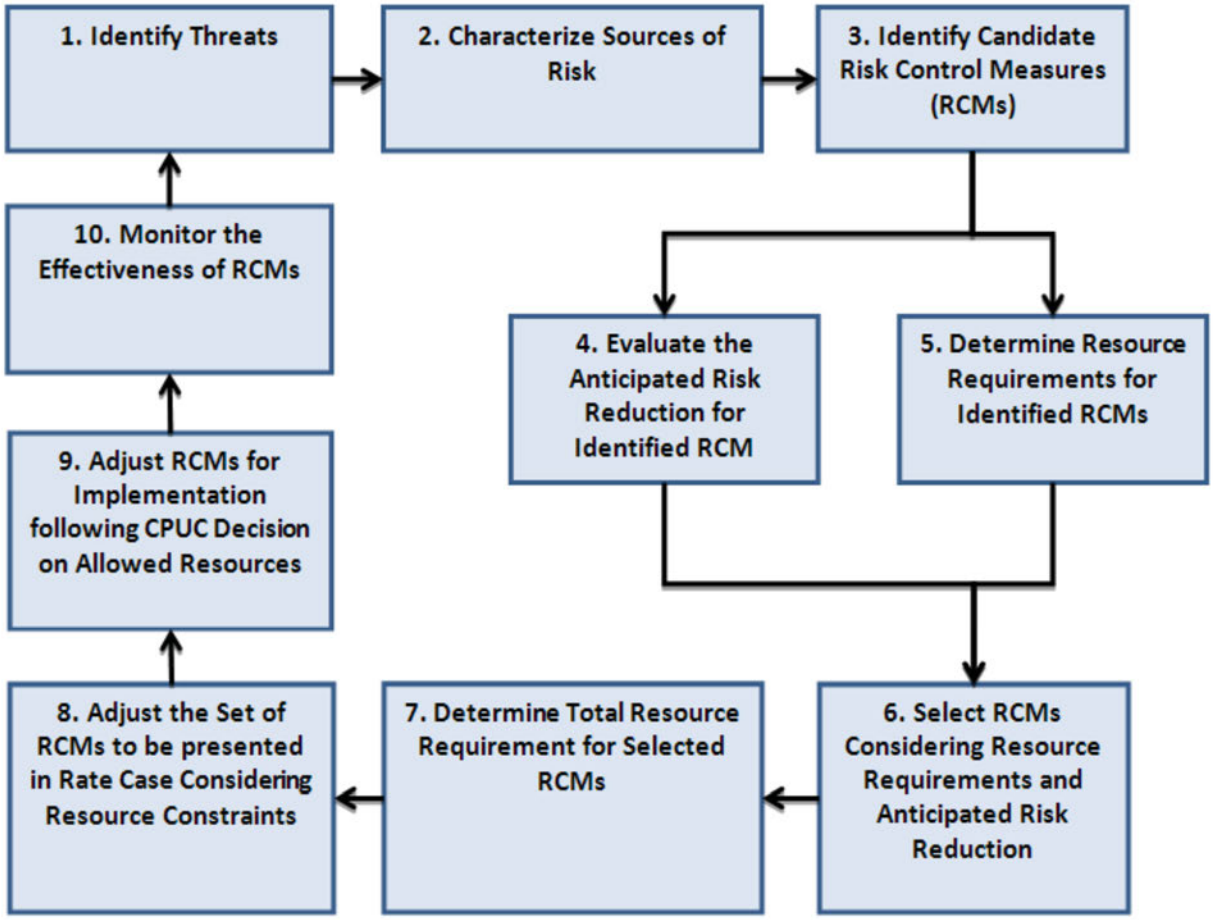
enterprise risks. This represents an important tool as our senior leaders make decisions to better prioritize and allocate resources to achieve greater risk reductions, where possible.

SCE's risk-informed decision-making framework is built on the foundation we described in SCE's Safety Model Assessment Proceeding (S-MAP) Application.[18] Since filing that Application, SCE has taken measured steps to enhance our internal risk management capabilities. We have benefitted from actively participating in the S-MAP process and collaborating closely with the Commission's Safety Enforcement Division (SED), intervenors, and other California utilities. While this RAMP report represents a prudent step forward in implementing a quantitative risk management framework, we are committed to continuously improving by incorporating best practices and lessons learned, and continuing the collaboration and knowledge-sharing with the Commission and external stakeholders.

The development of SCE's RAMP report followed Cycla's 10-step framework,[19] which is shown in Figure I-2 below. SCE describes our approach to each step in the sections that follow.

[18] A.15-05-002, SCE's Safety Model Assessment Proceeding application, submitted May 2015.
[19] In D.16-08-018, p. 2, this Commission adopted the Cycla Corporation 10-Step Evaluation Method as a common yardstick for evaluating how mature, robust, and thorough utility Risk Assessment and Mitigation Models and risk management frameworks are.

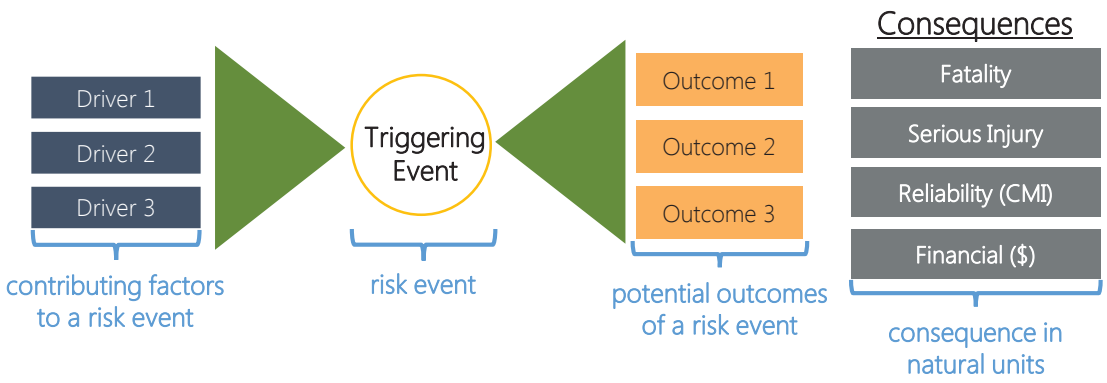
Figure I-2 – Cycla 10-Step Framework



- **Step 1: Identify Threats & Step 2: Characterize Sources of Risk**

SCE begins by developing an understanding of a risk event -- the fundamental elements contributing to the risk event (risk drivers), and the potential negative outcomes and consequences if the risk event is materialized. SCE applied the risk bowtie structure to enable us to consistently and systematically identify threats and characterize sources of risk. The risk bowtie is shown in Figure I-3.

Figure I-3 – SCE Risk Bowtie Structure



- **Step 3: Identify Candidate RCMs (Risk Control Measures)**

SCE has developed a multi-attribute risk scoring (MARS) approach for probabilistically quantifying risk in this RAMP report, based on available data and input from subject matter experts. SCE's MARS approach aligns with Multi-Attribute Value Function (MAVF) principals of the Settlement, and is discussed in more detail in Appendix 2 to this chapter.

For each risk, SCE then assesses existing controls, and identifies potential new mitigation measures that can reduce either the likelihood or the negative consequences of the risk.

- **Step 4: Evaluate the Anticipated Risk Reduction for Identified RCMS**

To estimate the anticipated risk reduction for control and mitigation measures, the effectiveness of each measure on reducing the likelihood and/or consequences of the risk is then estimated. The same MARS calculation is then conducted to estimate the post-mitigated risk score associated with each measure and the resulting risk reduction (benefits).

- **Step 5: Determine Resource Requirements for Identified RCMs**

Besides estimating effectiveness of each mitigation measure, SCE considers multiple factors including timing of deploying the mitigation, resource allocation, technology maturity, alternative mitigations, and other potential considerations[20] to develop a comprehensive and

[20] These requirements and considerations are deliberated in the Proposed and Alternative Plan sections within the individual RAMP risk chapters.

complementary suite of solutions to reduce risks. At this stage, SCE estimates what resources are needed for each mitigation.

- **Step 6: Select RCMs Considering Resource Requirements and Anticipated Risk Reduction & Step 7: Determine Total Resource Requirements for Selected RCMs**

Once we have estimated the cost and risk reduction associated with each mitigation, we then calculate the risk spend efficiency (RSE). This is a measure of risk reduction per dollar spent. It is calculated for each mitigation. RSE helps us estimate the effectiveness of each mitigation, and is also used to compare the effectiveness of different mitigations. RSE is one of the main considerations for selecting and developing a mitigation plan for each risk. We determine the total resource requirements to manage and mitigate a risk by aggregating the resource needs across the various individual mitigation measures contemplated for the mitigation plan. These two steps help us consider all resource requirements to mitigate a risk and to prepare for developing a practical and feasible mitigation plan.

- **Step 8: Adjust the Set of RCMs to be Presented in the GRC Considering Resource Requirements**

For each risk, the mitigation plan is then finalized, taking into account factors such as the feasibility of executing the overall portfolio and applicable resource constraints. The finalized mitigation portfolio for each risk is referred to as the Proposed Plan in this RAMP report. At this time, the RCMs identified in the Proposed Plan represent what we plan to request in the 2021 GRC. As applicable, SCE may further adjust these RCMs in SCE's 2021 GRC, in consideration of broader funding constraints, emergent risks, changes in available technologies, new data or information, or the emergence of alternative methods to mitigate the risk. In addition, for each risk, two alternatives to the Proposed Plan are also presented in each Chapter.

- **Step 9: Adjust RCMs for Implementation following CPUC Decision on Allowed Resources & Step 10: Monitor the Effectiveness of RCMs**

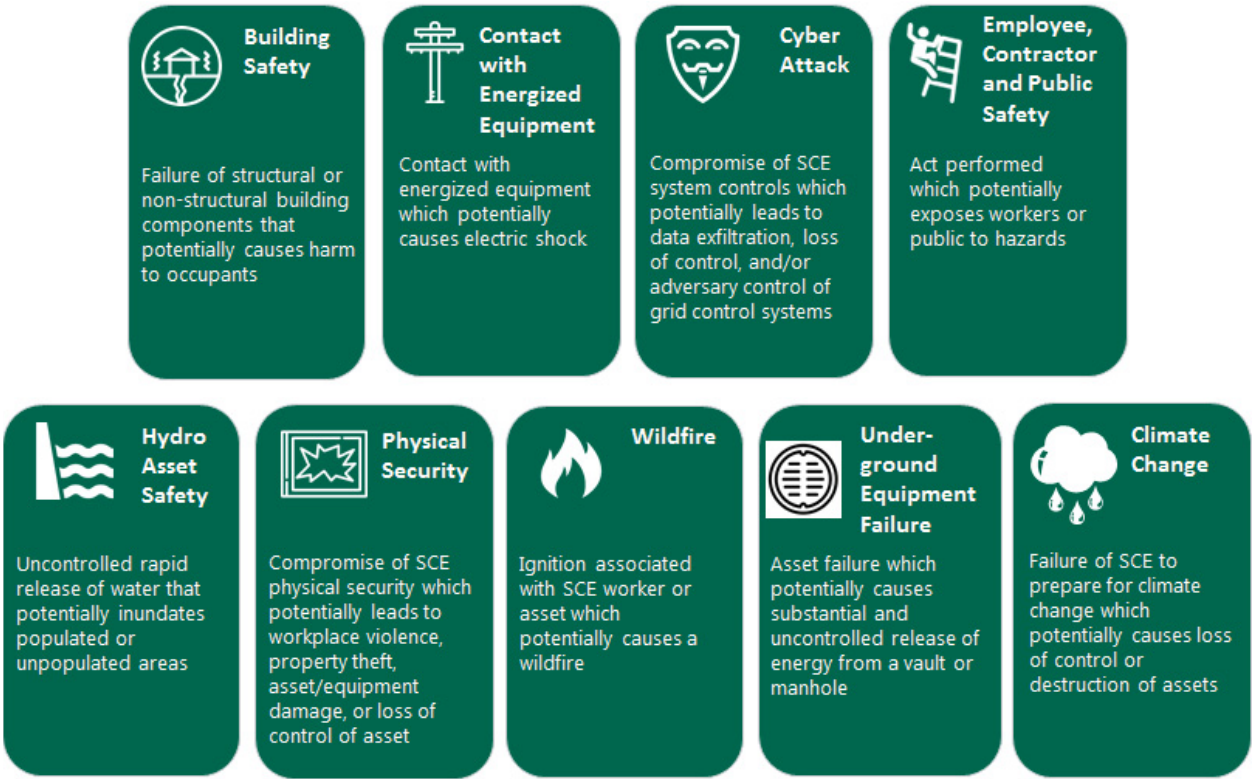
This RAMP report follows the first eight steps of the Cycla 10-step framework. The final two steps: Step 9 (adjust RCMs for implementation following CPUC decision on allowed resources), and Step 10 (monitor the effectiveness of RCMs), are not directly applicable to this RAMP report. However, for context, SCE plans to complete Step 9 following a decision on our

2018 GRC. Consistent with D.14-12-025, SCE plans to subsequently address Step 10, which may involve the completion of the Risk Mitigation Accountability Report.

G. RAMP Top Safety Risks & Process to Identify Them

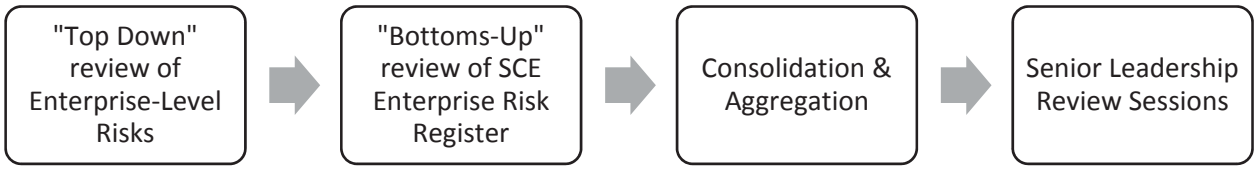
SCE went through a rigorous process to identify the top safety risks that merited inclusion in RAMP. Each of these top safety risks is summarized in Figure I-4 below, and examined in detail in the individual chapters of this report.

Figure I-4 – SCE RAMP Risks



The foundational component of this RAMP report is determining the top safety risks. SCE made significant efforts to help ensure we captured the right risks. We did this through the four general steps shown in Figure I-5:

Figure I-5 – General Process to Identify RAMP Risks



1. Top-down review of enterprise-level risk report

Every year, SCE identifies and evaluates the key enterprise risks facing the company. This effort is informed by a review of industry trends and research, internal risk analyses on major initiatives and key business functions, public policy efforts, and regulatory proceedings (including, most prominently, Commission proceedings). This effort also reflects feedback obtained through company-wide surveys and direct discussions with SCE leadership. Qualitative adjustment may be applied based on calibration discussions among cross-functional risk managers and among SCE officers. The list of key enterprise risks is reviewed and refreshed regularly, and changes when a new risk is identified and added, or retired and subtracted.

SCE regularly benchmarks and monitors what other utilities and Fortune 500 companies are classifying as their top risks. We also participate in various ERM forums and roundtables, including Edison Electric Institute (EEI), Deloitte, Gartner/Corporate Executive Board (CEB) Risk Management Leadership Council, and Risk Management Society (RIMS).

SCE evaluated this “top-down” enterprise risk refresh effort from 2017 with an eye towards safety-related risks identified in the report. SCE captured these safety-related risks to compare against the safety risks identified in our Enterprise Risk Register.

2. Bottoms-up review of SCE Enterprise Risk Register

SCE maintains an enterprise risk register that captures and assesses key risks from across the enterprise. The risk register has been populated over the past several years and lists our principal safety and reliability risks. It is intended to be a living document, and we update and modify it as necessary over time. To identify potential new and emerging enterprise risks and to validate existing risks, we engage in Company-wide online surveys directed to a large number of directors, managers, and subject matter experts, along with targeted interviews with specific and relevant risk managers. The interviews are typically followed by cross-functional group workshops and brainstorming sessions to further assess and validate the risk selection and nature of those risks.

To identify RAMP risks, SCE reviewed the risk register and identified risks with a potential major safety consequence (potential for serious injuries or higher) to consider in RAMP.[21]

3. Consolidation and aggregation

SCE evaluated the safety risks resulting from these top-down and bottoms-up analyses. This exercise involved consolidating duplicate risks and aggregating similar risks together. By using a common framework and terminology, we created a structured and uniform set of risks.[22] SCE applied the risk bowtie structure to enable this. The risk bowtie, as show in Figure I-3 above, is a way to systematically and consistently evaluate the drivers, outcomes, and consequences of a risk event.

In addition, SCE evaluated the relative order of impacts from each risk event. SCE considered whether a risk event would result in first-order direct safety impacts, or if it might result in second-order indirect safety impacts. As discussed further in Section I below, SCE is only measuring the first-order direct safety impacts resulting from a risk event. As such, SCE removed those risks that primarily focused on second-order, indirect safety impacts.

4. Review and refine with senior leadership

On several occasions, SCE discussed the potential RAMP risks with the leadership team to refine this consolidated set of safety risks. Further refinements were made based on these discussions. Sometimes, the scope of proposed risks were increased; other times the scope was reduced. For example, SCE was initially proposing to focus solely on building safety from the lens of seismic event risks. However, we expanded the scope to explore electrical hazards, building fires, and environmental events that could have potential safety impacts to workers in buildings. In other cases, we consolidated risks even further together. For example, SCE originally had a standalone Insider Threat risk. After much discussion, we determined that insider threat activities would be better served as drivers to the Cyberattack and Physical Security risk chapters.

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[21] Please refer to WP Ch. 1, pp. 1.2 – 1.4 *(Risk Register to RAMP Risk Mapping)*.

[22] For example, a key safety risk for SCE is human contact with energized conductor. This contact may occur for a variety of reasons, including but not limited to equipment failure, accidental contact, etc. In the process of structuring the RAMP risks, SCE addresses the contact with energized conductor in two chapters, according to the drivers of the contact: Chapter 7 (Employee, Contractor & Public Safety) evaluates human contact with energized conductor caused by an act an SCE worker performs. Conversely, Chapter 5 (Contact with Energized Equipment) evaluates contact with energized conductor caused by failure of overhead assets (e.g., wire down event), or failure of a third party to recognize his/her proximity to energized conductor (e.g., private party tree trimmers).

5. Discussion with external stakeholders

As mentioned in the Executive Summary above, on several occasions SCE met with external stakeholders to review and solicit feedback on the risks we proposed to include in RAMP, and to outline the analysis we were undertaking. SCE appreciates the collaborative feedback we received, and looks forward to further conversations as we move through the RAMP OII process.

6. Risks that were strongly considered for inclusion in RAMP

This process yielded nine risks, and in this RAMP report we have performed detailed probabilistic analyses regarding each risk. Through this process, some safety-related risks were omitted for various reasons. For context, some of these included:

Table I-II – Risks Not Included in RAMP

Risk	Description	Rational for Exclusion
Electrical System Failures - System-Wide Blackout	System-wide blackout caused by equipment, asset, or system failure.	Safety impacts would be secondary and indirect, which SCE is not capturing in this RAMP report (see Section I (Key Parameters and Assumptions Underlying SCE's RAMP Report) for further detail).
Vehicle/Aircraft Failure	Safety consequences caused by the actual failure of a vehicle, bucket truck, crane, helicopter, etc., and not human error.	Incidents due to asset failure (e.g., the vehicle has a problem, not the human operator) are very rare. For vehicles, fewer than 5% of incidents with OSHA-recordable injuries were potentially due to vehicle failure. For helicopters, based on FAA historical accident data and the current extent of SCE helicopter operations, the likelihood of potential safety incidents is low.
Customer Service System Outage	Failure or prolonged outage of SCE's customer service IT systems that manage our website, customer data warehouses, and electronic communications with our customers, leading to delays in handling power outage reporting or other public safety requests from our customers.	SCE found that most of the safety risks associated with this event were secondary and indirect.

H. Appendices: Qualitative Assessment of Other Safety Risks

While developing this RAMP report, SCE received valuable feedback from several external parties recommending that we address certain risks in the RAMP report that are not covered in the nine risk chapters. Accordingly, SCE includes two Appendix chapters that address the following risks using qualitative risk analysis, and one additional appendix that provides greater context concerning our seismic program.

- Nuclear Decommissioning (Appendix A): SCE addresses the safety risks associated with SCE's San Onofre Nuclear Generating Station (SONGS) during the process of decommissioning the facility. SCE mitigates these safety risks by carefully adhering to Nuclear Regulatory Commission (NRC) radiological safety regulations, as well as other requirements from Federal and State regulatory bodies.
- Transmission & Substation Asset Safety (Appendix B): In this appendix chapter, SCE qualitatively assesses direct safety risks associated with the transmission and substation systems.
- Seismic Events (Appendix C): As seismic events are incorporated into SCE RAMP risk chapters as a risk driver, SCE uses Appendix C to provide greater context to our overall Seismic program.[23]

I. Key Parameters and Assumptions Underlying SCE's RAMP Report

Consistent with Commission direction, SCE intends that the data, assumptions, and methods used to develop this RAMP report be transparent and understandable to the Commission and interested Parties. Throughout this report and associated workpapers, SCE documents the data and rationale used to evaluate the risk and risk mitigation activities for our top safety risks. We believe that this report will provide all parties, including Commission Staff, with the opportunity to understand the analysis, data and assumptions underlying our submission.

Because this is the first time SCE has developed a RAMP report, SCE had to consider and establish an approach for myriad issues that affect the evaluation of RAMP risks and mitigations. This section provides context into several of these issues, and explains how SCE approached them.

[23] Seismic events are included as a driver to the Hydro Asset Safety and Building Safety risks. A summary of SCE's seismic mitigation program is discussed in Appendix C (Seismic Events) of this RAMP report.

1. Risk Impacts Measured in RAMP

In this RAMP report, SCE only evaluates the immediate impacts of a risk event. That is, when a risk outcome occurs, SCE measures only the direct impacts of that outcome, and not those of subsequent outcomes which may ultimately result.

For example, consider the risk event of an underground equipment failure, which causes the power outage of traffic lights at a traffic intersection. SCE will measure, among other consequences, the resulting reliability impacts from that outage. In this RAMP report, SCE does not, however, evaluate the potential impacts from car accidents that occur because the traffic lights are out. While this secondary impact is certainly possible and SCE is of course concerned about it, we find it difficult to quantitatively forecast with any reasonable degree of confidence the number and severity of traffic accidents that would result from such a power outage. As a result, we evaluate only the immediate and direct impacts of the risk event (e.g., underground equipment failure) in this RAMP report.

The result of only evaluating first-order impacts is that the risk analyses found in this report likely underestimate the magnitude and extent of each risk. SCE may consider alternative means to address this in future RAMP reporting.

2. RAMP Time Period

SCE has evaluated risk, risk reduction, and RSE over the 2018-2023 period. SCE used 2018 as the first year to model risk, as this allows our risk baseline[24] to be firmly rooted in what we have experienced through 2017. This is similar to the "base year" concept in a GRC. SCE evaluates risk through 2023 as that corresponds to the final test year of our 2021 GRC.

SCE recognizes that only evaluating risk reduction and RSE over the 2018-2023 period can be problematic for mitigations with benefits and costs extending beyond 2023. This is especially the case for long-lived assets that are installed during the RAMP period, and then continue to operate and provide benefits for many years thereafter. There can be dissonance in RSE comparisons between this type of mitigation, and for example, an O&M expense-driven mitigation that has short-lived benefits. In these cases, the long-lived mitigation will have an RSE that is understated compared to the short-lived mitigation.

[24] For purposes of this RAMP report, the baseline risk level represents the estimated risk at the end of 2017.

To help us understand the implications of this, and to help build capabilities to capture and model long-term benefits and costs beyond the RAMP period, SCE has piloted an approach to capture the risk reduction benefits beyond 2023. Please refer to the Appendix of Chapter 8 (Hydro Asset Safety), which performs such an evaluation on the Hydro Asset Safety chapter. In addition, SCE performed a similar analysis on the Wildfire Covered Conductor Program, which can be seen in the Appendix to Chapter 10 (Wildfire). SCE plans to continue to evaluate how best to incorporate the full benefits and costs of risk mitigation activities, and we look forward to working with the Commission and interested parties to develop this capability.

3. Treatment of risk mitigation activities that appear in multiple risk chapters

In a few cases within this RAMP report, a control or mitigation may address multiple risks. Where this occurs, SCE either (1) models the benefit of the mitigation to the specific risk bowtie evaluated in the chapter, while incorporating the full cost of the mitigation, or (2) models the mitigation within the chapter of primary benefit, and qualitatively discusses how the mitigation affects the risk in the chapter receiving the indirect benefit. In cases of the former, SCE does not attempt to split or apportion the costs of that mitigation to each risk. Instead, the full costs of the mitigation are included in each chapter where a mitigation is modeled. However, within each chapter, *the risk reduction benefits* of that mitigation are quantified *only* with respect to its impact on that chapter's risk bowtie. In effect, this may underestimate the RSE of the mitigation as a whole. We are showing the full costs in each chapter, but not necessarily the full risk reduction benefits.

The controls and mitigations that are modeled in multiple chapters are identified in Table I-III. There are also several other controls and mitigations shared between the Wildfire and Climate Change chapters; these are discussed further in those respective chapters.

Table I-III – Controls & Mitigations in Multiple Chapters

Control/Mitigation	Contact with Energized Conductor	Wildfire	Climate Change
Overhead Conductor Program	X	X	
Covered Conductor	X	X	
Situational Awareness Tools		X	X

While costs may appear in multiple RAMP chapters, SCE will address any such duplication when developing our 2021 GRC request.

4. Financial Information Presented in RAMP

a. Cost Estimates

SCE has developed preliminary cost estimates for the 2018-2023 RAMP period for each control and mitigation activity. The costs are not jurisdictionalized. They represent total company unadjusted expenditures regardless of regulatory cost recovery mechanism. SCE presents these costs, both O&M and capital, in nominal dollars. For controls and mitigations funded through capital expenditures, SCE does not include capital-related expense, which typically amounts to less than 2-3% of the capital spend. As this exclusion does not materially change the risk analysis, SCE will address capital-related expense in the 2021 GRC.

It is important to note that these costs are estimates at a point in time. Using reasonable efforts, SCE has developed our estimated forecast costs for each control and mitigation in this report, based on the information available when we prepared this RAMP report. We expect our 2021 GRC will further refine the cost estimates shown here.

b. Recorded Costs

Within each chapter, SCE includes the 2017 recorded costs for each compliance and control activity. These costs represent total company, unadjusted costs in nominal dollars, including balancing/memorandum accounts. SCE has provided a workpaper that details the recorded and forecast costs for each compliance, control, and proposed mitigation activity modeled in our RAMP report from 2013 – 2023.[25]

5. Use of Subject Matter Expertise (SME) in RAMP

Wherever possible and practicable, SCE has used data pertaining to our own system to support our risk analyses. Where this is not available, we look to other utilities in California, or other utilities around the country, for data and information comparable to our operating environment and size. When such data does not exist, we rely on the judgment of subject matter experts (SMEs) to develop assumptions for risk models.[26] Where this occurs, SCE has endeavored to explain the assumptions and processes used to develop such judgment in the chapter or associated workpapers.

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[25] Please refer to WP Ch. 1, p. 1.1 *(2013 – 2023 Recorded and Forecast Costs for Controls & Mitigations)*.
[26] These categories of information are not mutually exclusive. For example, the availability and use of SCE-specific data does not cancel out exercising appropriate judgment.

J. Global Challenges and Lessons Learned in Development of RAMP Report

This section identifies general challenges we have faced and overall lessons learned that we have obtained through developing our first RAMP report. In addition, each chapter identifies lessons learned that are specific to that chapter.

1. RAMP Time Period

In some cases, the RAMP time period of 2018-2023 does not fully capture the duration of expected costs and benefits. For example, conductor upgrades have a useful life measured in decades. On the cost side, mitigations installed during the RAMP period can require ongoing maintenance costs that extend beyond 2023.

The most common issue resulting from limiting the analysis time period to 2018-2013 was a failure to fully capture the longer-term risk-reduction benefits of a long-lived Control or Mitigation. This leads to an understatement of the RSE.

This analytical limitation is most visible in the chapters addressing Wildfire, Contact with Energized Equipment, Underground Equipment Failure, and Hydro Asset Safety. SCE believes that the mitigations in these chapters, particularly the longer-lived infrastructure programs, would have a materially higher RSE if the long-term benefits were captured.

RSE is not the only factor SCE considered in selecting proposed mitigation portfolios, and the duration of particular Controls and Mitigations is considered qualitatively. However, addressing long-term benefits will be a goal for future RAMP filings.

As previously discussed, SCE used the Hydro Asset Safety risk to pilot a methodology to capture the complete time horizon of both costs and benefits. This is shown in Appendix 1 to the Hydro Asset Safety chapter. SCE calculated a complete lifetime of both costs and benefits, accounted for factors such as degradation of mitigation effectiveness over time, and then discounted the costs and benefits to a present value. SCE performed this analysis with several discount rates to illustrate the impact under different scenarios. In addition, SCE performed a similar analysis on the Wildfire Covered Conductor Program, which can be seen in the Appendix to Chapter 10 – Wildfire.

SCE found that a long-term analysis did materially change the RSEs in that chapter, and that using different discount rates can change the results of the present value analysis, depending on how long the mitigation is used.

2. Primary and Secondary Impacts

In this RAMP report, SCE measured risk outcomes at the level of immediate (i.e., primary) impacts across specific consequences (serious injuries, fatalities, financial, and reliability). SCE did not measure secondary impacts (for example, the hypothetical car accident that occurs because a traffic light is out due to underground equipment failure).

At this time, attempting to measure secondary impacts in this RAMP report would be challenging and highly unlikely to achieve an acceptable degree of certainty. SCE concluded this after extensive internal discussions confirmed that secondary impacts cannot be identified, defined, or measured with the level of certainty and credibility necessary to inform the immediate RAMP risk analysis calculations.

For example, using the hypothetical scenario above of a traffic light that has lost power, one would need to speculate on questions such as the time of day, how many cars pass through the intersection, the occupancy of each car, whether an accident occurs, whether the accident results in serious injuries or fatalities, how many accidents occur before power to the traffic light is restored, whether law enforcement had been on hand to direct traffic after the light was reported out, etc. As this limited example illustrates, attempting to define and measure even a modest slice of the potential secondary impacts of a risk event is fundamentally speculative and uncertain.

SCE discussed these challenges extensively during development of its RAMP filing, and SCE appreciates that the "solution" to this difficulty—only measuring primary impacts relative to the outcomes defined in the bowtie statement—presents a view of the risk that does not cover the full range of potential impacts. SCE notes that both risk outcomes and mitigation effectiveness measurements ignore secondary impacts; in other words, just as SCE is not including secondary impacts in measuring the size of risk outcomes, SCE is not including secondary impacts in measuring the risk reduction potential of mitigations. SCE will continue to evaluate secondary risks for potential inclusion in future risk analyses.

3. Mitigations in Multiple Chapters

As discussed in Section I.3, SCE identified mitigation measures that provide benefits across multiple risks. SCE took the approach of calculating RSE values independently. As a hypothetical example, assume that a mitigation costs $100 and provides 20 MARS points of risk reduction in Chapter A, and 30 MARS points of risk reduction in Chapter B. The RSE for that mitigation would be calculated as follows for each chapter:

- In Chapter A, the RSE is 20 / $100 = 0.2
- In Chapter B, the RSE is 30 / $100 = 0.3

This approach potentially understates the risk reduction by not showing its combined impact across both risks. The alternative would be to sum the total risk reduction. In the hypothetical example above, the RSE would be calculated as follows:

- (20 + 30) / $100 = 0.5

SCE determined that, although it might understate some RSE values, accepting this limitation for our initial RAMP report was appropriate until further exploration (e.g. through the S-MAP process, etc.) could inform a more comprehensive approach.

4. The Bowtie Framework

Although SCE's utilization of the bowtie framework for risk analysis predates this RAMP report, the RAMP report provided further opportunity to apply the bowtie approach across numerous business areas. This helped us develop a deeper understanding of the strengths and weaknesses of the approach.

The bowtie provides a simple and effective means to translate high-level conceptions of risk (e.g. "wire-down" or "worker injury" or "building fire") into a more structured understanding that articulates the difference between risk drivers, risk events, and risk outcomes. The bowtie's ability to define and disaggregate the components of a risk can be especially helpful when working with subject matter leads who may be experts in their particular line of business, but are less fluent in the discipline of risk definition and analysis. Furthermore, the bowtie serves as an effective risk organizing principle regardless of whether the ensuing analysis is quantitative or qualitative.

The bowtie is most effective when applied to risks where the outcomes are largely indifferent to the drivers. For example, if an energized wire is on the ground, the safety risk and the potential range of outcomes have little to do with why the wire is down in the first place (the driver). True to the bowtie's design, the potential outcomes are independent of the potential drivers.

This feature of the bowtie—its design feature that maintains independence between drivers and outcomes—was a challenge for risks that are more extensive in scope or include a complex network of drivers and outcomes.

For example, the risks in the Building Safety chapter are highly diverse, from earthquakes to weather conditions to fires. The drivers and outcomes for these risks are tightly linked; an electrical failure will not lead to the outcome of building shaking, but such building shaking would occur from a seismic event. In these cases, additional analysis can be required to help ensure the bowtie adequately captures driver and outcome data. Furthermore, applying the bowtie to a diverse or complex risk usually requires broadening the risk event in the center of the bowtie to a point where it can be overly generalized.

SCE highlights these aspects of the bowtie framework to explain the bowtie strengths and weaknesses in the context of both RAMP and utility safety risk management more broadly. Despite the limitations mentioned above, SCE sees the bowtie as an appropriate approach to proceed with for the foreseeable future, unless or until a more fitting alternative is identified.

5. MARS/MAVF Framework

As described previously, SCE used the MARS framework to implement the concept of a Multi-Attribute Value Function (MAVF), which allows risks to be understood in terms of both natural units and a generic, unit-less risk score. MARS scoring can provide a mechanism for enabling apples-to-apples comparisons across dissimilar risks and mitigations, as long as the underlying risk inputs are consistent.

However, the same MARS feature that allows for cross-risk comparisons—the conversion of natural units into unit-less risk points—results in a metric that offers no intuitive sense of value by itself. Unlike natural units, which can be understood intuitively on both a standalone basis and relative to other company goals or projects unrelated to RAMP, an individual MARS result can only be compared to other MARS results that were derived using an identical framework.

Finally, as with many risk scoring systems, the MARS/MAVF framework relies on key underlying assumptions such as the ranges and weights of attributes; any internal or external party that disagrees with those assumptions might struggle to find value in the resulting MARS values.

Despite these limitations, a MARS/MAVF framework provides an essential complement to measuring risk from the perspective of natural units. As noted above, absent converting risk measured in natural units into MARS points, it would not be possible to compare risk outcomes on a comparable basis.

This RAMP report provided SCE with an opportunity to educate organizational units within the Company on the MARS/MAVF concepts. SCE plans to continue these efforts as these types of risk scoring processes are further integrated into internal decision processes and risk management activities. SCE also attempted to make the MARS score more intuitive by setting a maximum combined score of 100 (meaning a risk that has the highest impact in all dimensions would have a total MARS score of 100). This provides an intuitive reference point for the relative value of a MARS score for an individual risk.

6. Data and Risk Quantification

RAMP's focus on quantification lends itself to risks that can be narrowly defined and readily measured. Risks that are larger in scope or complexity, that are challenging to limit to discrete risk events, or that are difficult to quantify can be a challenging fit with the RAMP analysis framework. Hence, SCE presents the findings and analysis in this RAMP report as a basis to help *inform* risk-related decision making, but not as a sole or controlling basis for such decision making.

Similar to challenges faced by other utilities, quantification can be challenging where the RAMP approach required data that SCE had not previously tracked. In the individual risk chapters, SCE has noted areas in which improved data availability or tracking should enhance the quantitative analysis.

Quantification was also challenging in areas that lacked a historical precedent of risk events, regardless of whether SCE was tracking data in that area. For example, SCE has never experienced a hydro dam failure, and thus has no historical body of failure events that can inform a forward-looking forecast. SCE attempted to find industry or external data in such cases, but those sources may not provide the same level of accuracy or relevance as a forecast based on historical data directly from the risk population in question. Furthermore, in areas in which data is sensitive or classified (e.g. cybersecurity or safety risks in litigation), complete industry data may not be available.

SCE plans to address the above challenges with several approaches:

- New or improved data collection in areas where the data exists, but had not been tracked in a way that was conducive to RAMP analysis needs. Details of these efforts and plans are provided in the concluding section of each risk chapter.
- With the knowledge and experience gained from its initial RAMP filing, SCE will be more able in future RAMP filings to spot areas where SCE-specific data is not available, and to devote more time upfront to identify external data

sources and develop the necessary assumptions and analytical approaches to adapt external data to the particular risk in question.

- With regard to cases in which data is available but a poor fit, or cases in which risk drivers or outcomes are challenging to model, SCE notes that the RAMP process led to significant advancements in SCE's internal capabilities to perform advanced risk modeling and analysis. SCE's abilities in these areas are significantly stronger as a result of developing the RAMP filing, and SCE expects this gain to yield benefits in the next RAMP filing when it comes to quantifying and modeling complex risks.

K. Availability of Risk Model Data and Results

SCE will furnish the risk models and data files used to perform the risk analysis in this RAMP report upon request. The size of these files and the volume of data within them make it prohibitive to send via email and without proper context. To request the risk models, please send an email to Case.Admin@sce.com and reference the 2018 RAMP report in the transmittal.

Due to the amount of data produced in each model, SCE has developed a more intuitive reporting interface for stakeholders to view and evaluate the inputs and outputs of the risk models. This was developed through Microsoft's PowerBI tool. This is available to anyone with an internet connection; no software installation is needed. Data from the charts and tables in this tool can be downloaded directly to your computer for further analysis. We encourage stakeholders to use this tool to help understand the quantitative aspects of this RAMP report.

For directions on how to obtain access to this resource, and for a tutorial on how to navigate the tool once you have access, please see the associated workpapers.[27,28] Additional detail on this tool and its contents can be found in Chapter II – Risk Model Overview.

[27] Please refer to WP Ch. 1, pp. 1.5 – 1.8 *(RAMP Power BI Access Form & Sign-up Instructions)*.
[28] Please refer to WP Ch. 1, pp. 1.9 – 1.40 *(RAMP Power BI User Guide)*.

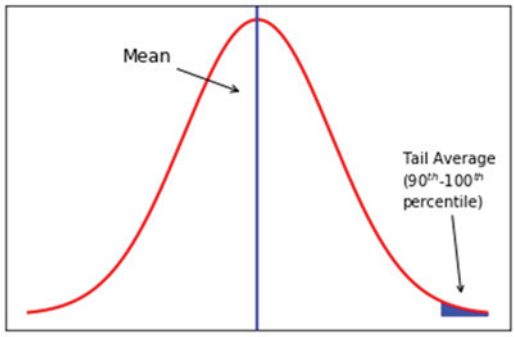
II. Appendix 1: RAMP Summary Results

A. Mean vs. Tail-Average Results

Throughout this RAMP report, SCE provides results within each chapter in terms of "mean" and "tail-average." It is important to understand the difference in these two results. SCE's probabilistic risk model simulates 10,000 scenarios based on the data inputs and parameters of bowtie elements, including drivers, triggering events, outcomes, consequences, etc. Figure II-1 illustrates this difference in these results.

- The mean is the average of all 10,000 simulation results.
- The tail-average is the average of the worst 10% of all 10,000 simulation results.

Figure II-1 – Distribution of Modeling Results



For some RAMP risks, it may be more productive to evaluate results on a mean basis; for others, tail-average would be more relevant. For example, the Hydro Asset Safety chapter considers the consequences resulting from the failure of a dam. A dam failure has not, and is not expected to, happen regularly. In fact, such a dam failure has an incredibly low likelihood of occurring, but when it does occur, the consequences can be catastrophic and widespread. Such an extreme risk may be more appropriate to evaluate on a tail-average basis.

Conversely, the Employee, Contractor, and Public Safety chapter considers consequences resulting from acts performed by workers that lead to injuries. Unfortunately, this happens on a more frequent basis – there are a number of safety incidents ranging from ergonomic issues, to injuries requiring first aid, to serious injuries requiring hospitalization that

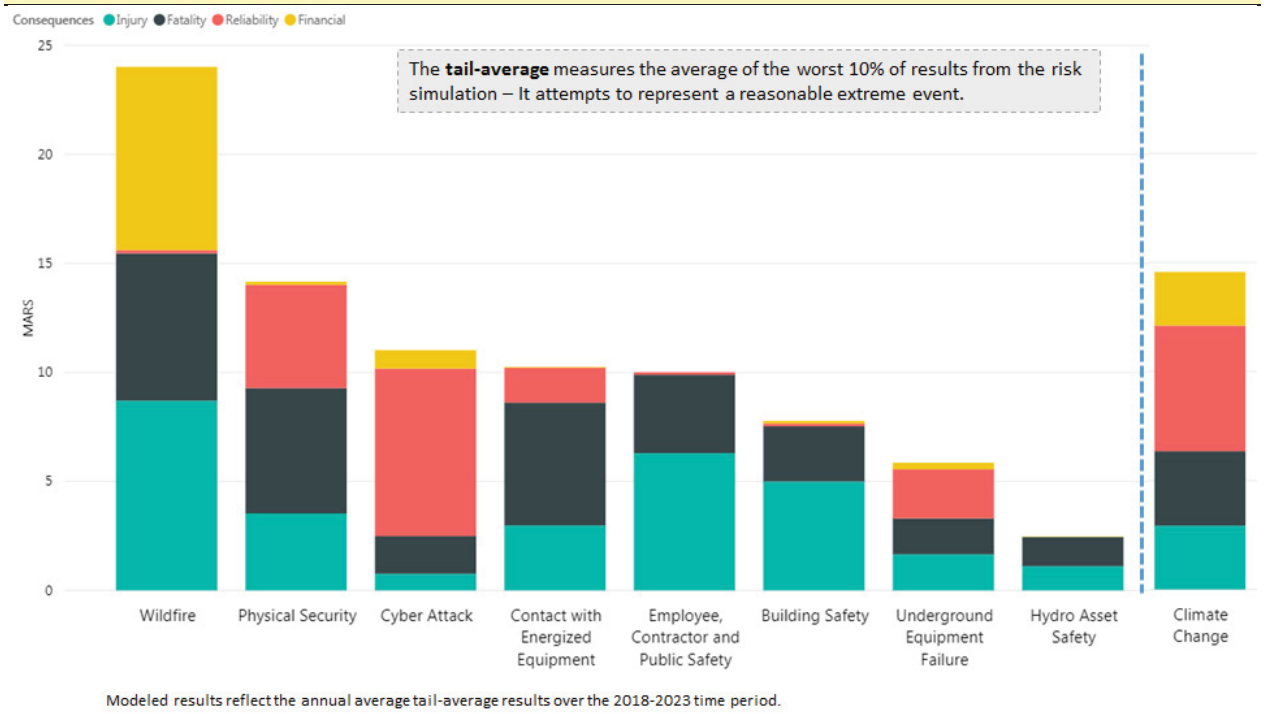
occur each year. When these incidents happen, the impacts are typically isolated to the person performing the act. Considering these incidents occur with greater frequency and have localized impacts, it may be more appropriate to evaluate on a mean basis.

Because both the mean and tail-average results can provide valuable insights into the nature of each risk, SCE has included both results throughout this RAMP report.

B. Summary Baseline Results

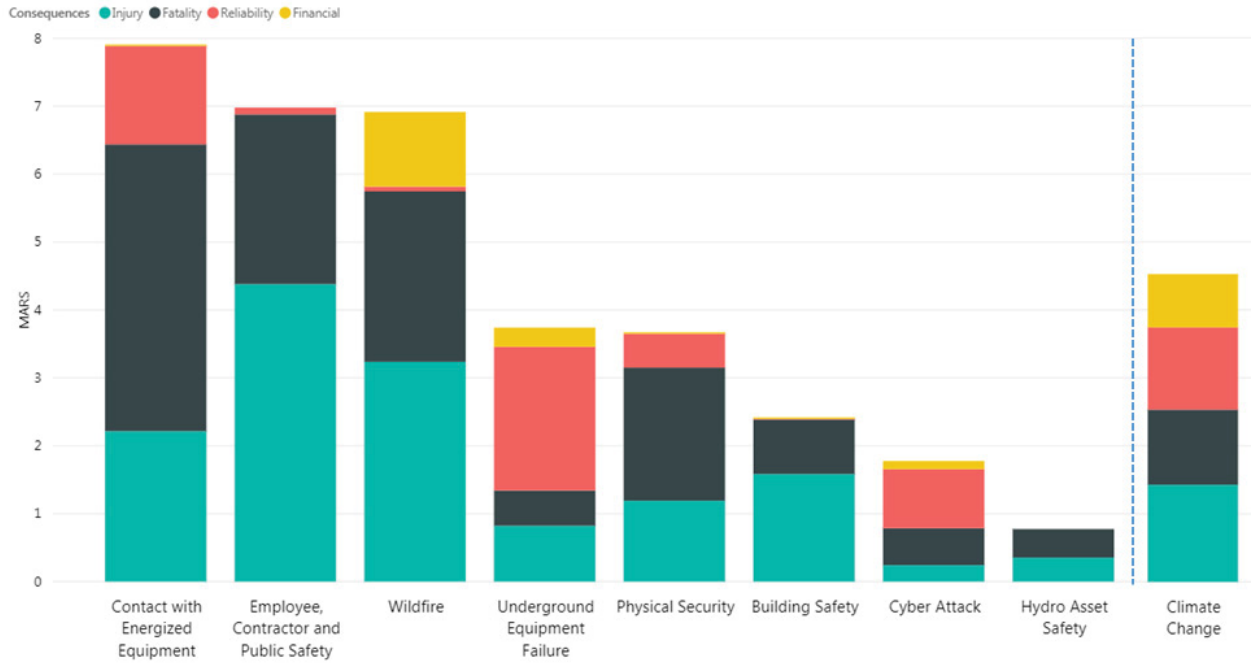
Figure II-2 and Figure II-3 show the baseline scores for the nine risks modeled in RAMP, on a tail-average and mean basis. These baselines reflect an average of the modeled results over the 2018 – 2023 period.[29]

Figure II-2 – Baseline Risk Scores (Tail-Average - MARS)



[29] Climate Change is shown off to the side for two reasons: (1) As is discussed in Chapter 12 – Climate Change, the risks associated with climate change are impactful to varying degrees over the near-, medium-, and long-term time horizons. This RAMP analysis reflects impacts over the 2018-2023 RAMP period. We were not able to capture the gradual and long-term impacts, such as drought, snowpack, sea-level rise, etc. over the near-term using the RAMP model. (2) In the RAMP analysis, SCE modeled the near-term extreme (99th percentile) climate change risks (extreme rain, heat, and wildfire). This means that the climate change results shown are much further on the distribution of outcomes than the tail-average results shown for the other eight risks. As such, the comparison is not entirely like-for-like.

Figure II-3 – Baseline Risk Scores (Mean – MARS)



Modeled results reflect the annual average mean results over the 2018-2023 time period.

III. Appendix 2: RAMP Report Aligns with the S-MAP Settlement Agreement

As described below, SCE's RAMP report is consistent with the S-MAP Settlement Agreement (Settlement) that SCE and several other parties submitted to the CPUC on May 2, 2018, and to which the Commission has issued a Proposed Decision adopting.

A. Use of a Multi-Attribute Value Framework (MAVF)

For this RAMP report, SCE developed a MAVF approach, referred to as MARS, consistent with principals that S-MAP settling parties agreed on. This approach: (1) measures potential risk consequences in terms of natural units; and (2) converts natural units into a standardized unit-less risk score that can be compared across risks.

Consistent with the S-MAP Settlement, SCE is evaluating the risk impacts associated with the following consequences: Safety (measured separately through Serious Injuries[30] and Fatalities), Reliability (measured in customer minutes of interruption (CMI)),[31] and Financial (measured in dollars).

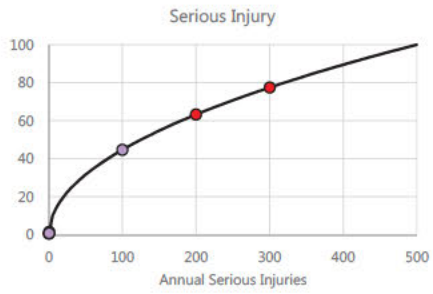
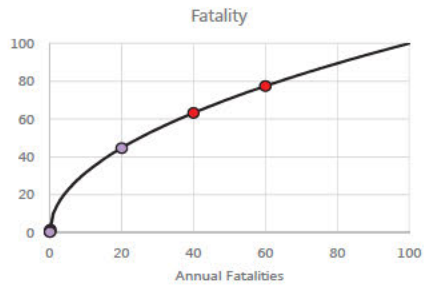
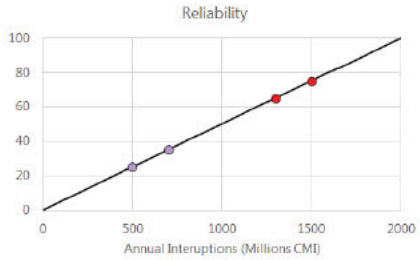
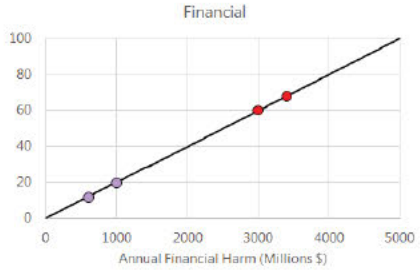
And in accordance with the process outlined in the S-MAP Settlement, SCE's RAMP report utilizes:

- Attributes to define potential types of consequences (e.g., reliability) and natural units to measure the consequence (e.g., customer minutes of interruption).
- An upper and lower bound to define a range for each attribute (e.g., $0 to $5B for a financial attribute).
- A scaling function that translates each range of natural units into a 1-100 score of generic unit-less risk score.
- Weights that indicate the relative value of attributes.
- Multi-attribute risk scoring (MARS), which is the weighted average sum of the unit-less risk scores across all the applicable attributes for each risk. Under SCE's method, each risk can have a maximum MARS score of 100.

Figure III-1 summarizes the MARS attributes that SCE uses in this RAMP report.

[30] For purposes of this RAMP report, SCE is generally defining serious injuries using the EEI Serious Injury definition. Please refer to WP Ch. 1, pp. 1.41 – 1.46 *(EEI Serious Injury Definition)*.
[31] Customer Minutes of Interruption can be applied to SCE's customer base to derive another common reliability metric, SAIDI (System Average Interruption Duration Index).

Figure III-1 – Summary of SCE MARS Placeholder Values

Consequence *(Natural Unit)*	**Range**	**Scaling Function**	**Weight**
Serious Injury *(# of Serious Injuries)*	0 – 500	<u>Square Root</u> 	25%
Fatality *(# of Fatalities)*	0 – 100	<u>Square Root</u> 	25%
Reliability *(Customer Minutes of Interruption – CMI)*	0 – 2 Billion CMI	<u>Linear</u> 	25%
Financial *USD ($)*	0 – $5 Billion	<u>Linear</u> 	25%

1. Selection of Ranges

Ranges accommodate the worst reasonably possible consequence for each risk over the course of the year. To estimate ranges for each consequence, SCE considered past events that SCE or other utilities experienced (e.g., financial consequences that California utilities and their customers experienced as a result of the year 2000 energy crisis) or potential scenarios in the future (e.g., an eight-hour outage across the entire SCE service territory)

2. Selection of Scaling Functions

The scaling function aligns each consequence's natural unit range to a generic, unit-less range from 0 – 100. This allows for translation to a common metric for comparison.

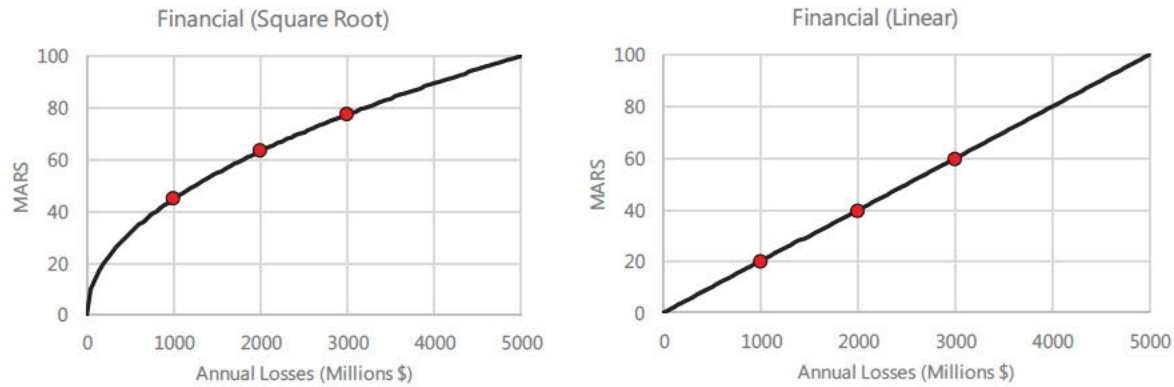
Table IV – Scaling Function Rationale

Consequence	Scaling Curve	Description / Rationale for Use
Serious Injury	Square Root	This curve exhibits a steep slope on the lower end of the scale, reflecting the gravity for safety consequences. It amplifies the impact of safety versus the consequences which have a linear curve. This reflects SCE's intolerance for safety-related consequences.
Fatality		
Reliability	Linear	Maintains simplicity of measurement in converting to MARS. It does not presume a level of customer tolerance to short- or long-duration outages.
Financial	Linear	Maintains simplicity of measurement in absence of data showing relative level of aversion to impacts at the lower and upper bounds of range.

Figure III-2 provides an illustrative comparison of the differences in MARS score for a financial consequence when using the square root scaling function versus the linear scaling function. The square root function has a steeper curve and results in a higher MARS score versus a linear scaling curve given the same natural units,[32] further amplifying the impact of safety consequences to the overall aggregate MARS for each risk. This variance is most pronounced on the left-hand side of the curve, when the number of natural units are less.

[32] This is true except for the first and last value (0 and maximum value of the natural unit range), where the MARS score will be the same for both the square-root and linear curve.

Figure III-2 – Illustrative Comparison of Linear and Square Root Scaling Functions



Natural Units *(x-axis)*	MARS *(y-axis)*	
Annual Losses	**Square Root**	**Linear**
$1,000	44.7	20
$2,000	63.2	40
$3,000	77.5	60

3. Selection of Weights

SCE selected equal weights (25%) across the four consequences. This creates a 50% total weight on safety consequences (serious injuries and fatalities) in the MARS score. This priority weighting on safety consequences, coupled with the square root scaling functions used for serious injuries and fatalities, make safety a significant component of MARS in this RAMP report.

B. Enterprise Risk Register (ERR) as the Starting Point for RAMP Risk Selection

Similar to the process described in the Settlement, SCE utilized its ERR as a starting point for the process that resulted in the nine risks treated in RAMP.

Due to the timing of completion of the Settlement, SCE was not required to, and did not have sufficient time to, calculate a Safety Risk Score using the full MAVF approach for all ERR risks that have the potential for a Safety impact. In other words, SCE did not calculate MARS values for all risks in its ERR. Further, while SCE conducted in-person outreach sessions with several external stakeholders to describe its risk selection process, it was impossible to hold a formal workshop as indicated in the procedural terms of the Settlement. That is because the Settlement was not yet adopted. SCE will comply with all requirements and take any steps outlined in the adopted Settlement.

C. Use of the Bowtie Diagram

For each of the identified risks included in this RAMP report, SCE utilizes a bowtie methodology, which structures risk as a function of drivers (each with an annual frequency), a discrete risk event, potential outcomes (each has a probability of occurrence), and consequences of those outcomes that are measured in natural units. The bowtie is reflected in Figure I-3 above. Risk is probabilistically quantified for each bowtie as a function of probability and consequence using Monte-Carlo simulations. SCE calculated risk on both an expected value (EV) basis (i.e., the mean), and on a tail-average basis. The Settlement indicates a preference for EV, but allows EV to be supplemented by alternative calculations such as tail-average value.

D. Mitigations Linked to Drivers and/or Outcomes

Controls (existing mitigations) and new mitigations[33] are defined and quantified in terms of their ability to reduce driver frequency, affect the probability of an outcome, and/or reduce the severity of a consequence.

E. Measurement of Risk Reduction and Calculation of Risk Spend Efficiency (RSE)

In this report, SCE uses MARS to measure risk before and after a mitigation is applied, which quantifies how much risk is reduced by the mitigation. The risk reduction is then divided by the dollar cost for the mitigation. This provides an RSE value that can be used to compare the relative risk-reduction efficiency of different mitigations.

F. Other Areas of Note Comparing SCE's RAMP to the S-MAP Settlement

SCE integrated the concept of "dynamic analysis" in a limited fashion by adjusting driver frequency over time to account for expected changes in real-world conditions (e.g., a driver based on an asset failure would increase if certain maintenance programs are not performed).

SCE has endeavored to meet the Settlement's standard for transparency, through actions such as providing the full set of modeling assumptions and outputs upon request, and by providing an intuitive and interactive tool (Power BI) to easily review the results of our analyses.

SCE used historical internal data (e.g., past wire-down frequency) or validated industry data (e.g., FEMA data on ratios of injuries per building fire) as much as possible prior to resorting to internal and external subject matter expertise.

[33] Please note that the Settlement does not distinguish between "controls" or "mitigations."

As discussed previously, SCE has tested the concept of present valuing benefits and costs of risk mitigation activities over their useful lives, in the Hydro Asset Safety chapter. We plan to continue to work with stakeholders to refine this method for potential broader use in future analyses.

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Risk Model Overview

Chapter 2

Rosemead CA
November 15, 2018

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I. Risk Model Overview

A. Introduction

The risk model ("model") utilized in this RAMP report quantifies risk, and the effects that different mitigations have on that risk, using a probabilistic approach. This model enables a more data-driven, risk-informed decision making approach in this RAMP report.

In this chapter, SCE details the mechanics of the model and the process used to calculate Multi-Attribute Risk Scores (MARS), risk reduction, and Risk Spend Efficiency (RSE) for controls and mitigations. This chapter also discusses the innovative reporting capabilities that SCE has developed so that stakeholders can readily view and evaluate the results of the model outputs.

SCE looks forward to further conversations and exchanges with Commission Staff and other stakeholders as they view the results of the model outputs. We plan to discuss this further and answer questions when we hold our upcoming workshop in December of 2018. SCE is available for, and looks forward to, informal collaborative conversations as well.

B. Moving towards a probabilistic approach

This RAMP report represents a significant step forward for SCE in analyzing safety-related risks using probabilistic approaches. This is SCE's first generation RAMP model. Like any quantitative model, the quality of the outputs are largely dependent on the quality of the inputs. Some risk chapters have an abundance of data; others can benefit from capturing and tracking more extensive data. All require judgment in how to apply the data we have to the model parameters. As we build our data sets over time, and as we further refine the model itself, SCE will use the model to increasingly support our risk-informed decision making.

The following sections detail the probabilistic nature of the model.

1. Use of Monte Carlo simulation

The risk model uses a technique called Monte Carlo simulation to achieve the results described above. Here is an explanation of what this is:

> *"Monte Carlo simulation performs risk analysis by building models of possible results by substituting a range of values – a probability distribution—for any factor that has inherent uncertainty. It then calculates results over and over,*

each time using a different set of random values from the probability functions.

By using probability distributions, variables can have different probabilities of different outcomes occurring. Probability distributions are a much more realistic way of describing uncertainty in variables of a risk analysis. It tells you not only what could happen, but how likely it is to happen."[1]

2. Modeling distributions and not single data points

Instead of using a single data point to define a model input parameter (e.g., drivers, outcomes, consequences), SCE's model uses statistical distributions for each input parameter. The benefit of doing so is to account for uncertainty in the input data.

For example, assume that a risk driver occurs an average of 10 times per year. SCE will build a distribution around those 10 events. This allows the Monte Carlo simulation to pick points on or around those 10 events to account for variation in the inputs. For example, there could be a small probability (say 5% for illustrative purposes) that there could be 20 events for that driver sometime in the future. A non-probabilistic model would not capture this low-probability event and its associated impact. SCE's model not only captures the various points along the distribution, but also the probability of those events occurring.

Figure I-1 shows a generic risk bowtie. Each component of the bowtie designated with a green box is modeled using a distribution. The choice of distribution used, and its associated parameters (e.g. mean, standard deviation, etc.), is based on historical data, other external data sources, and/or modeling judgment.

For example, Driver #1 could be modeled using a Poisson distribution; Outcome #1 with a Binomial distribution; Reliability impacts for Outcome #1 using an Exponential distribution; and Financial impacts for Outcome #1 using a Lognormal distribution.[2] Although there are many types of distributions in mathematical literature, SCE uses seven of the more

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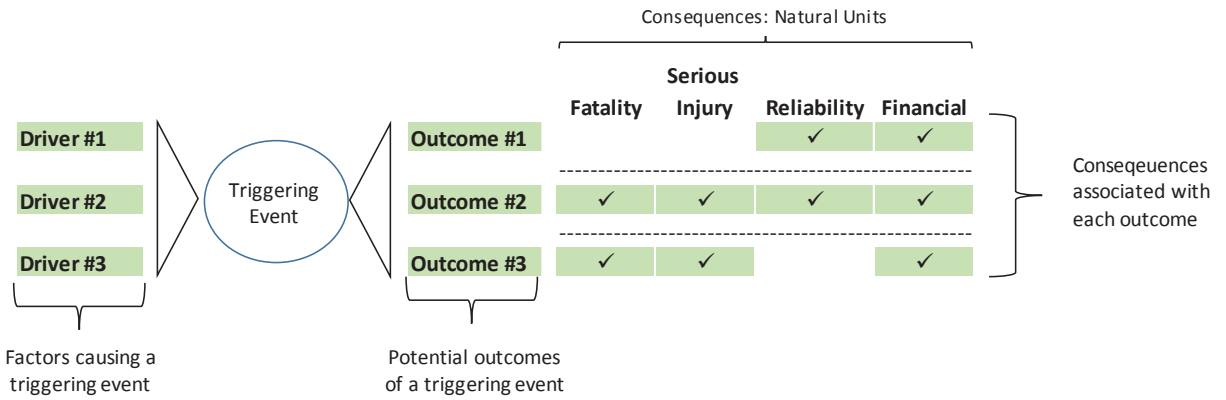
[1] Monte Carlo Simulation information is *available at* http://www.palisade.com/risk/monte_carlo_simulation.asp

[2] Section II of this chapter provides a description of the distributions used in this example.

common distributions when modeling bowtie components in this report. These distributions are described in Section II of this chapter.

Figure I-1 - Illustrative Risk Bowtie

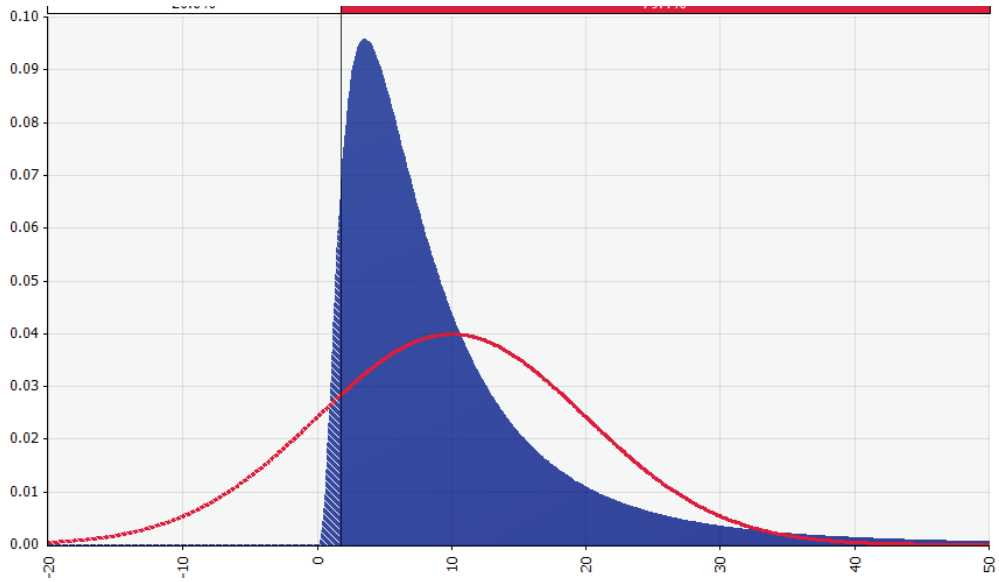


3. Specifying distribution parameters to convey risk

The choice of distributions and associated parameters is critical to the resulting probabilities of each component. Figure I-2 illustrates this by plotting two distributions on the same graph: a normal distribution (red line) and a lognormal distribution (blue shaded region). These distributions are drawn using the same mean (10) and standard deviation (also 10). Even though the shapes of these two distributions are very different, the area under each curve is the same.

The lognormal distribution is visibly “left-skewed,” which results in a greater likelihood that a number less than 10 is picked when the simulation is run. In contrast, the normal distribution presents the shape of a typical bell curve, where the mean (in this case 10) is the most likely number chosen. In addition, even while both the lognormal and normal distributions have the same mean and standard deviation, the lognormal distribution has a fatter “tail” (heading toward the right-hand side of the graph), which results in a greater likelihood that a tail, or extreme event, will occur. Depending on the data being evaluated, different distributions can lead to different model results. The process that SCE used to identify the appropriate distributions to model is detailed in Section III.

Figure I-2 – Lognormal and Normal distributions

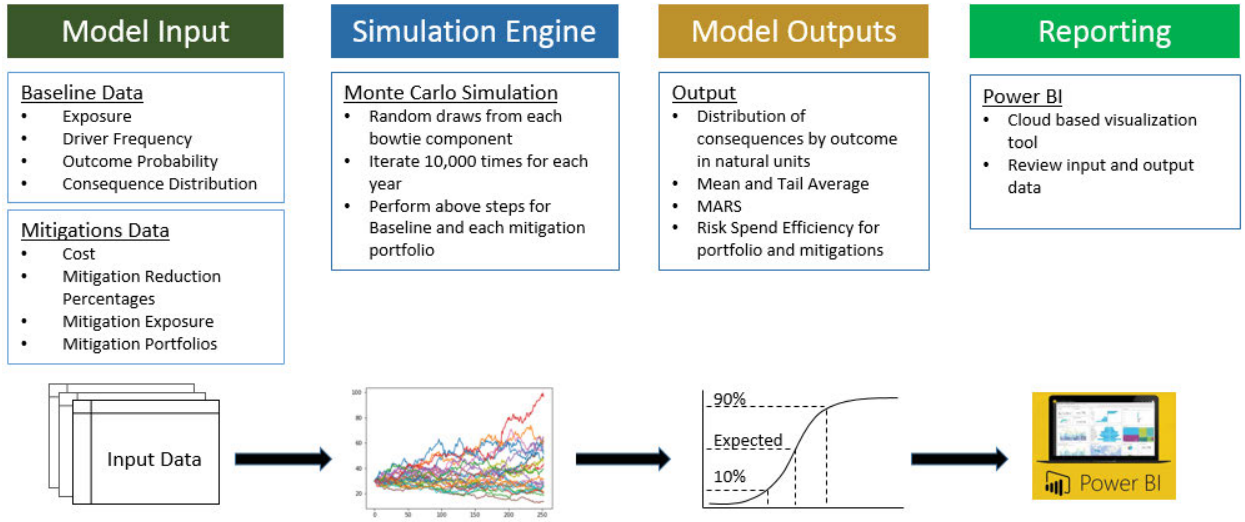


C. Model Architecture

This section provides an overview of how we designed our model, which is summarized below in four stages and shown in Figure I-3:

- Model Inputs
- Simulation Engine
- Model Outputs
- Reporting

Figure I-3 – Model Architecture Overview



1. Model Inputs

In this RAMP report, SCE is evaluating risk over the six-year period from 2018 – 2023. Each data input is required to have specific values for each year, for the applicable years over the 2018-2023 period. The table below defines the key model inputs.

Table I-1 - Summary of Model Inputs

Inputs	Description
Driver Frequency	Drivers are the factors causing a triggering event. We measure drivers based on the number of times they occur each year.
Triggering Event Frequency (TEF)	The triggering event frequency is the sum of each driver's annual frequency. *Therefore, it is not a model input. Instead, it is a calculated value.*
Outcome Probability	Outcomes are measured by their probability of occurring when the triggering event happens. We measure outcome probability as a percentage; the sum of all outcome percentages equals 100%.
Consequence Distribution Parameters	Consequences measure the type and severity of impacts resulting from the outcome. For each outcome's applicable consequences (serious injuries, fatalities, reliability, and financial), we identify the appropriate distribution type and its associated parameters (e.g. mean, standard deviation). Section III details how distributions and parameters are selected.
Mitigation Reduction Percentage	For each control or mitigation, we determine its effect on reducing one or more drivers, outcomes, and/or consequences. We measure this by calculating a percentage reduction that the control/mitigation reduces each applicable bowtie component by. For example, a mitigation might decrease the annual frequency of a particular driver by 10% and also reduce the financial consequence (associated with a particular outcome) by 20%.
Cost	The annual nominal costs (Capital and O&M) associated with each control/mitigation over the 2018-2023 period are estimated and provided to the model.

Inputs	Description
Exposure	We measure exposure as the scope of the risk that is being analyzed. For example, when measuring the risk of hydro dam failures, the exposure may be the entire portfolio of SCE's high hazard hydro dams, or a subset of those.
Mitigation Exposure	We measure the exposure associated with each mitigation as a percentage of the Exposure input. For example, if the Mitigation Reduction Percentage is 10%, but the Mitigation Exposure is 20%, then the mitigation effectiveness of this mitigation is 10% * 20% = 2%. Some risk chapters explicitly utilize the mitigation exposure input fields, while other risks incorporate the mitigation exposure into the Mitigation Reduction Percentage.

SCE begins the risk evaluation process by identifying and quantifying the inputs described above. These inputs provide the quantitative parameters for each component of the risk bowtie.

2. Simulation Engine

SCE uses the @RISK[3] software plugin for Microsoft Excel to run the Monte Carlo simulations. The next section describes the steps the simulation engine takes to arrive at distributions of results for each risk being evaluated. For reference, in Appendix 1 we provide an illustrative example of how these steps are applied when analyzing a risk.

a. Simulation of Baseline Risk

The simulation starts by systematically "drawing" data points from the distributions of each component of the bowtie. These data points form the basis of one simulation of the risk over the course of a year. The simulation then repeats this drawing 10,000 times, and aggregates the results.

Going from the left side of the bowtie (drivers) to the right side (outcomes and consequences), the simulation specifically performs the following:

[3] *See* Information re: @RISK software *available at* http://www.palisade.com/risk/

1) Simulation of Drivers

A random number is selected from each driver's distribution. These numbers represent the annual frequency for each driver. When added together, these annual driver frequencies result in the annual TEF.

2) Simulation of Outcomes

The TEF number is then probabilistically split into the different outcomes. The simulation uses the binomial distribution[4] to simulate the number of events associated with each outcome. For example, if the TEF is 100, and the outcome probability for Outcome #1 is 10%, then probabilistically the number of events from the TEF allocated to Outcome #1 is 10.

3) Simulation of Consequences

Each outcome is associated with one or more consequences (serious injury, fatality, reliability, and financial). In the example above, Outcome #1 results in reliability and financial consequences. If Outcome #1 occurs 10 times, then the model will draw 10 numbers from the reliability distribution and add those numbers together. In addition, it will draw 10 numbers from the financial distribution and add those numbers together. This process will continue for all other outcomes. For example, since Outcome #2 results in four consequences, it will draw samples from each of the four consequence distributions.

The model has now, for this one draw, calculated the overall impact for each of the consequences associated with each outcome. This process is repeated 10,000 times, for each year, so that each consequence and outcome combination will have a collection of 10,000 numbers for each year. This is what we refer to as a distribution of results. This distribution of results is specific to each consequence attribute in terms of natural units (e.g. customer minutes of interruption (CMI) for reliability, dollars for financial, etc.).

---

[4] The binomial distribution is a discrete distribution where the random variable chosen (the output) is a positive integer and is used in the Outcome portion of the bowtie. It is a probability distribution of the number of successes in a sequence of *n* independent trials based on a probability of success (*p*). In the bowtie, the *n* would represent the TEF of each scenario and the *p* is the outcome percentage. *See* Section II for more information.

b. Simulation of Mitigated Risk

Next, the model simulates the effects of the controls and mitigations on the baseline risk. This is done in three steps:

- Mapping individual mitigations to each portfolio;
- Developing an updated set of model inputs based on the mitigations;
- Running the same Monte Carlo simulation process as performed for the baseline risk, for each of the three mitigation portfolios.

1) Mapping of individual mitigations to each portfolio

Controls and mitigations are bundled together into portfolios. These portfolios represent collective options for addressing the risk. In accordance with RAMP requirements, SCE has put together three portfolios: Proposed Plan, Alternative Plan #1, and Alternative Plan #2. Table I-2 illustrates how this general mapping occurs.

Table I-2 – Mapping of individual mitigations to portfolios

	Proposed	Alternative 1	Alternative 2
M1 -Mitigation 1	X	X	X
M2 -Mitigation 2		X	X
M3 -Mitigation 3		X	
M4 -Mitigation 4	X	X	
M5 -Mitigation 5			X

In this example, the Proposed Plan consists of two mitigations: M1 and M4.

2) Revised set of mitigation inputs

Each mitigation plan is then evaluated based on its aggregate effect on the baseline risk inputs. This requires evaluating not only the effect that each control or mitigation has on the baseline risk, but the effects that each control or mitigation have on each other.

As discussed previously, each mitigation can influence any or all of the following baseline risk inputs: 1) driver frequency, 2) outcome probability, and/or 3) consequence impact. For example, M1 could reduce the frequency of Driver #1 by 10%, and also reduce the mean of the fatality consequence distribution for Outcome #2 by 20%.

When mitigations are compiled into a mitigation plan, we must understand how one mitigation may affect another. For example, in the Proposed Plan shown above, there are two mitigations: M1 and M4. Suppose the baseline driver frequency for Driver #1 is 200, and M1 reduces the frequency of Driver #1 by 10%. The new "mitigated" driver frequency based on the effect of M1 would be 200*(100% - 10%) = 180, or a 10% reduction to the frequency of Driver #1.

However, M4 may also reduce the frequency of Driver #1. In this scenario, M4 will reduce the frequency of Driver #1 by 20%. This 20% reduction is now to the reduced driver frequency after M1 has been accounted for (180). As such, the new frequency for Driver #1 now equals: 180*(100% - 20%) = 144. The aggregate effect of both M1 and M4 results in a 28% reduction in the frequency of Driver #1. This is in contrast to a 30% reduction if we were to simply add the reductions from M1 (10%) and M4 (20%).

The key concept that the model implements is that mitigation reduction percentages are compounded when used to compute the mitigated parameter.[5] Because of compounding, the same mitigation can have different risk reduction values, depending on the other mitigations in the portfolio. This compounding approach is applied to each baseline risk input, and for each of the three mitigation plans.

3) Rerun using the revised set of mitigation inputs

For the next step, we now run each mitigation plan (separately) through the model using the new mitigated input values. For example, for the Proposed Plan simulation, the input for Driver #1 will now be set at an annual frequency of 144, instead of 200 as used in the baseline risk simulation. As with the baseline risk simulation, each mitigation plan is simulated 10,000 times for each year. Similarly, the simulation produces a distribution of results specific to each consequence.

[5] The order of how the mitigation percentage reductions that are applied to the baseline risk has no impact. For example, whether the 20% or the 10% is applied first, the final mitigated frequency number will still be 144 in this example.

3. Model Output

After the model simulations are completed for both the baseline risk and the three mitigation plans, we perform certain post-processing calculations to aggregate simulation results, convert to MARS, and derive RSE values.

a. Aggregation

The model calculates the overall mean and tail-average[6] (TA) for each consequence for each year. For example, as shown previously, there are three outcomes (Outcome #1, Outcome #2, and Outcome #3) that result in financial consequences. The model calculates the mean of the financial consequence for each of the outcomes. This step will add those together to provide an aggregated financial consequence value. This will similarly be done for the TA results.

At the end of this process, there will be an overall mean and TA for each of the consequences for each year. This process is repeated for baseline risk and for each of the mitigation plans.[7]

b. MARS

SCE then converts the mean and TA of each consequence, in natural units, to a common unit-less metric so that different consequence results can be added together to show total risk levels. This is known as MARS.[8] Table I-3 is a sample calculation example that converts natural units, on a mean basis, to MARS. The same steps would be taken to convert the TA, in natural units, to MARS.

---

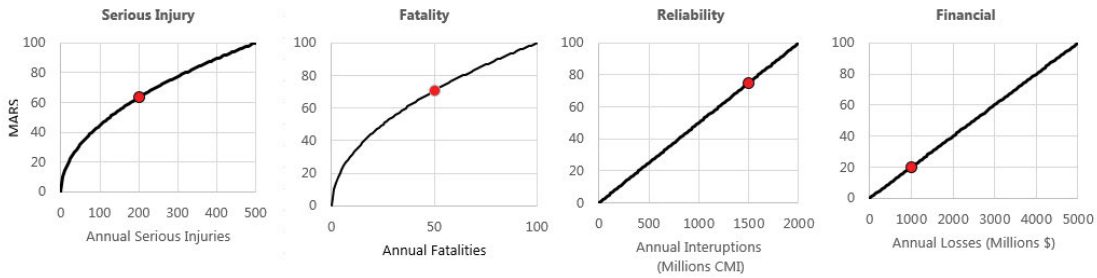
[6] Please refer to RAMP Overview Chapter, Appendix 1 (RAMP Summary Results) for additional discussion on using mean and tail-average results.

[7] *See* Appendix 1 of this Chapter for an additional example of this.

[8] Please refer to RAMP Overview Chapter for further discussion on how SCE arrived at the MARS approach and how we developed the placeholder values for its component parts.

Table I-3 – Example: Conversion from Natural Units to MARS

		Consequences (Natural Units)			
		Serious Injury	Fatality	Reliability (CMI)	Financial ($)
a	Mean	200	50	1.5 Billion	1 Billion
		MARS Calculation			
b	Weights	25%	25%	25%	25%
c	Scaled Score	63.25	70.71	75.00	20.00
d=b*c	Apply Weights	15.81	17.68	18.75	5.00
		Consequences (MARS Units)			
		Serious Injury	Fatality	Reliability	Financial
		15.81	17.68	18.75	5.00
	Overall MARS (out of 100)	57.24			



- Row (a) presents the overall mean for each of the four consequences.
- Row (b) shows the MARS weights for each of the four consequences. Each consequence is assigned an equal weight of 25%.
- Row (c) calculates the scaled score, in MARS, of the mean (in natural units) for each of the four consequences. The scaling curve (black line) represents the relationship between the x-axis (in natural units) and y-axis (MARS).[9] For example, the mean of the reliability consequence is 1.5 billion CMI. We find 1.5 billion CMI on the x-axis, identify the point on the curve directly vertical to it (see red dot), and determine the y-intercept (which in this example is 75 MARS).
- Row (d) now applies the weight in Row (b) to the scaled score in Row (c) to arrive at a scaled and weighted MARS score for each consequence. Using the same reliability example, a 25% weight is applied to the MARS score of 75, which equates to a scaled and weighted MARS score of 18.75.

[9] In this RAMP report, SCE uses square root scaling functions for the serious injury and fatality consequences, and linear scaling functions for the reliability and financial consequences. More detail on why these scaling functions were chosen for each consequence can be found in Appendix 2 of Chapter 1 (RAMP Overview).

The steps above for the MARS conversion from natural units for reliability can by summarized by the following equation:

$$\frac{1.5\ Billion}{2\ Billion} * 100 * 25\% = 18.75$$

In this equation, 1.5 billion is the number of CMI, 2 billion is the top end of the reliability range, and 25% is the MARS weighting.

The MARS for each consequence are added together to arrive at an overall MARS for each risk or mitigation plan. In this example, this risk has an overall MARS score of 57.24. The highest MARS score is 100.

c. Risk Spend Efficiency

The RSE is a metric to determine the cost efficiency of a mitigation or mitigation plan at reducing risk. The RSE calculation is:[10]

$$RSE = \frac{Baseline\ MARS - Post\ Mitigation\ MARS}{Expenditures}$$

In this RAMP report, SCE calculates the total RSE for each control and mitigation over the six-year 2018-2023 RAMP period. We also calculate the RSE for each of the three mitigation Plans, both by year and over the entire RAMP period.

It is important to note that because the maximum MARS score is 100, and because most of our controls and mitigations require much more than $100 to execute, the RSE scores are all small numbers (mostly less than one). This is purely a product of the RSE math equation, and bears no indication to the actual efficiency of a mitigation. Most importantly, RSE is a relative metric – it is most meaningful when used to compare controls and mitigations within a RAMP chapter. Therefore, whether the RSEs are less than one or greater than one

[10] Due to the number of decimals places created by the RSE calculation, SCE scales the RSE by one million, to show the RSE in terms of millions of dollars.

million, there is no difference since the magnitude of the RSE is comparable only on a relative basis between controls and mitigations. Table I-4 provides an illustrative comparison of this.

Table I-4 – Illustrative Comparison of Relative RSE Scores at Different Magnitudes

	RSE of Control A	RSE of Control B	Difference (B to A)
Scenario 1	1,000	2,000	100%
Scenario 2	0.001	0.002	100%

1) Individual Mitigation Risk Reduction

The model provides RSE results for each of the three mitigations plans. However, we must perform a few additional calculations to derive RSE for each control and mitigation. We must allocate the risk benefits from the mitigation plans to the individual controls and/or mitigations. We illustrate how this is done through the following example.

Consider the simplistic bowtie example in Figure I-4, which contains one driver, one outcome, and one consequence.

Figure I-4 – Simple Bowtie (Baseline Risk)

The total number of serious injuries for this risk is 10 (10 TEF x 1 Serious Injury per Event = 10 Serious Injuries). The baseline MARS is therefore:

$$\sqrt{\frac{10}{500}} * 100 * 25\% = 3.54$$

In this equation, 10 is the number of serious injuries, 500 is the MARS range, 25% is the MARS weight, and the square root is used because of the square root scaling curve used for serious injuries in this RAMP report.

2) Single Mitigation Scenario

Now, consider a scenario where there is one mitigation (M1) which reduces the driver frequency by 20%, as shown in Figure I-5, at a cost of $15 million. M1 reduces the driver frequency to 8, (10 x (100% - 20%)).

Figure I-5 – Single mitigation scenario

The number of serious injuries after M1 is deployed is now 8. Therefore, the *mitigated MARS* is:

$$\sqrt{\frac{\mathbf{8}}{500}} * 100 * 25\% = 3.16$$

The portfolio RSE is:

$$RSE\ (Portfolio) = \frac{3.54 - 3.16}{\$15M} = 0.025$$

The risk reduction in this scenario for M1 is [3.54 (baseline risk) – 3.16 (mitigated risk)] = 0.38. Since there is only one mitigation, M1 has the same RSE as the portfolio, namely 0.025.

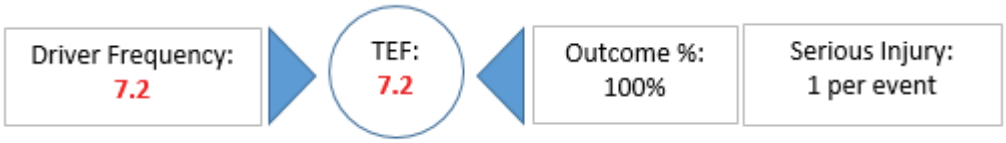
Importantly, because of the non-linearity of the serious injury scaling curve, a reduction from 10 to 8 serious injuries *will not* be the same MARS as a reduction from 5 to 3 serious injuries.

3) Multiple Mitigations Scenario

Here is a second scenario which introduces a mitigation portfolio containing two mitigations (M1 and M2). M1 is the same as above (provides a 20% reduction to the driver frequency at a cost of $15M). M2 also reduces the driver frequency, but by 10% and at a cost of $10 million.

Considering the driver reductions for both mitigations, the new mitigated driver frequency is 7.2, calculated using the compounding technique described earlier in this chapter: (TEF) * (1 – M1 Reduction) * (1 – M2 Reduction). This is calculated as follows: 10*(1-10%)*(1-20%) = 7.2. This is illustrated in Figure I-6.[11]

Figure I-6 – Multiple Mitigation Scenario



The number of serious injuries after applying the two mitigations is now 7.2. The mitigated MARS is now 3:

$$\sqrt{\frac{7.2}{500}} * 100 * 25\% = 3$$

The portfolio RSE is now 0.022:

$$RSE\ (Portfolio) = \frac{3.54 - 3}{\$10M + \$15M} = 0.022$$

The total risk reduction of the portfolio is (3.54 – 3) = 0.54. To calculate the RSE for each mitigation (M1 and M2), we must now allocate this risk reduction back to the two mitigations. To do this, we consider how much M1 contributed to the total risk reduction, on a proportional basis, versus M2, based on their respective mitigation reduction percentages:

$$M1\ risk\ reduction\ contribution = \frac{M1\ Reduction\ \%}{(M1\ Reduction\ \%\ + M2\ Reduction\ \%)} * Total\ Risk\ Reduction$$

[11] Please note that in the actual model, the output of a driver and outcome distribution will be a discrete number and not a decimal. This is only an illustrative example.

$$M1\ risk\ reduction\ contribution = \frac{20\%}{(20\% + 10\%)} * 0.54 = \mathbf{0.36}$$

Due to the compounding effect, the risk reduction for M1 in this multiple-mitigation example (0.36) is different than the risk reduction for M1 in the single-mitigation example (0.38).

Using the same method, we calculate the risk reduction provided by M2 in this example:

$$M2\ risk\ reduction\ contribution = \frac{10\%}{(20\% + 10\%)} * 0.54 = \mathbf{0.18}$$

Now that we know the risk reduction for each mitigation, we can calculate their respective RSE, as follows:

$$RSE\ (M1) = \frac{0.36}{\$15M} = 0.024$$

$$RSE\ (M2) = \frac{0.18}{\$10M} = 0.018$$

This concept of proportionally allocating the benefits back to the individual mitigations is carried throughout the bowtie, for drivers, outcomes, and consequences. When risks have multiple drivers, outcomes, and consequences, as well as mitigations which can affect any of those bowtie components, then the level and number of proportionality calculations can rise quickly.

4. Reporting

The model and post-processing calculations that SCE employs produce a large volume of data. These data are important to have so that we can understand and analyze each

aspect of each risk. However, it can be cumbersome to sort and mine through all of this data, across all nine risk chapters, using standard spreadsheets and static files.

As such, SCE used an interactive reporting tool to transform this raw data into easily digestible information. This is done through Power BI, a Microsoft cloud-based business analytics software that harnesses the key strengths of Microsoft Excel (analytical capabilities, charting capabilities) and PowerPoint (presentation capabilities). SCE used this tool to design interactive reports and dashboards for users to better understand the risk analysis, including but not limited to:

- Results that can be toggled between mean or tail-average;
- Results that can be toggled between natural unit or MARS;
- Baseline risk inputs;
- Control and mitigation effects on the bowtie;
- Control and mitigation mapping to mitigation plans;
- Risk reduction and RSE for each control/mitigation, and for each mitigation plan;
- Comparative results across the nine risks;

SCE pulls data from the models into Power BI. We then used Power BI to help calibrate within and across the RAMP risks, identify trends and outliers, quickly spot and correct modeling and transposition errors, and serve as our "source of truth" when populating relevant charts and tables used throughout this RAMP report.

SCE believes it is beneficial to share this tool with stakeholders to help them understand and evaluate the results of our RAMP report. Because Power BI is cloud-based, no additional software is needed other than an internet browser. To request access to this tool, please follow the instructions found in the workpapers for Chapter 1 (RAMP Overview).[12] In addition, a user guide for how to navigate the RAMP Power BI tool is also provided in the workpapers for Chapter 1 (RAMP Overview).[13] Please note that Power BI is a one-way tool.

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[12] Please refer to WP Ch. 1, pp. 1.5 – 1.8 *(RAMP Power BI Access Form & Sign-up Instructions)*.

[13] Please refer to WP Ch. 1, pp. 1.9 – 1.40 *(RAMP Power BI User Guide)*.

Users cannot change the data, but can download the data associated with each chart/table and conduct their own analysis.

D. Summary of Risk Modeling Lessons Learned[14]

The model discussed in this chapter is SCE's first-generation RAMP risk model. Accordingly, we learned many things as we developed and applied it for risk analysis. We believe we have meaningfully advanced our probabilistic modeling capabilities using this model. However, there are areas we have identified for further consideration as we look to continuously improve our capabilities.

1. Undervaluing risk reduction and RSE in mitigations that span multiple risks

As discussed in the RAMP Overview chapter, mitigations can benefit multiple risks. For purposes of this RAMP report, the model is set up to evaluate each risk independently. Similarly, the model we developed can only calculate the effect each mitigation has on one risk at a time. This means that the total risk reduction benefits, and associated RSE, of each of these mitigations are not fully captured within each risk chapter.

Whenever this occurs in this RAMP report, SCE models the mitigation's effect on each risk independently within each risk chapter. However, we include the full cost of the mitigation in each chapter. This has the effect of *artificially lowering the RSE by including the full cost of the mitigation, but only part of the full benefits.*

SCE will consider how to address this issue on a going-forward basis.

2. Degrees of confidence in modeling mitigation effectiveness

Whereas SCE uses distributions to model the baseline risk input parameters (driver frequency, outcome probability, consequence impacts), we use a single percentage to model the risk reduction associated with each mitigation's effect on each input parameter. In modelling the uncertainty or confidence level of our baseline risk inputs, we can vary the width of each distribution; for example, a larger width (standard deviation) means more uncertainty, and smaller width (standard deviation) means less uncertainty.

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[14] Please refer to WP Ch. 2, pp. 2.1 – 2.3 (*Risk Model Lessons Learned – Additional Detail)* for additional detail on these Lessons Learned.

As SCE collects more data to support fitting a distribution, this concept could be applied to the mitigation reduction percentage inputs as well. For example, if the mitigation reduction percentage is set at 15%, but there is high confidence that this estimate is accurate, then the standard deviation assigned to this particular mitigation would be small (for example, +/- 2%). But if the confidence level in this estimate is low, the standard deviation could be much higher, for example +/- 10%). This framework would thus capture the uncertainty around the mitigation's effectiveness factor. SCE may consider future updates to our model to account for this potential improvement.

3. Identifying control and mitigation impacts for each year in the RAMP period

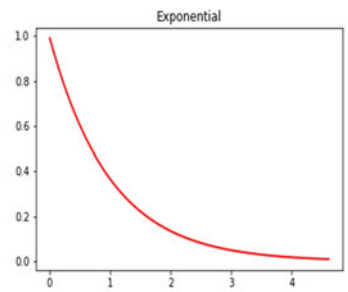
As previously discussed, the model produces RSE by year for each mitigation plan (Proposed, Alternative #1, Alternative #2). However, the model does not directly produce RSE by year at the individual control or mitigation level. We currently need to take the results of the model at the Plan level, and allocate them to each control and mitigation. During this post-processing effort, we calculate the risk reduction and RSE of each individual control and mitigation over the six-year 2018 – 2023 period. We have not yet built in the capability to further allocate these individual control or mitigation benefits on an annual basis. We understand that it may be beneficial to identify the specific risk reduction benefits and RSE of individual controls and mitigations on an annual basis, rather than in aggregated form over the six-year period. Accordingly, we plan to consider how we might incorporate those calculations into future iterations of the model.

II. Distribution Types Used in SCE's RAMP Report

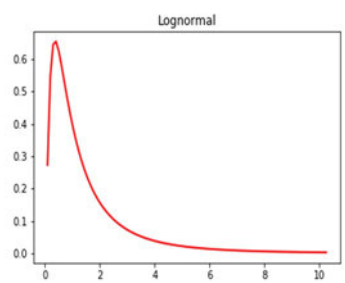
The figures below show the probability density function (PDF) of the distributions that are used in the model. The PDF is used to determine the probability that a random variable lies between two values. The higher the peak, the higher percentage a random variable will be drawn from that point.

There are two categories of distributions used in this RAMP report: continuous and discrete. Random variables drawn from a continuous distribution can assume an infinite number of different values, while random variables drawn from a discrete can only assume a finite number of values (in this case integers).

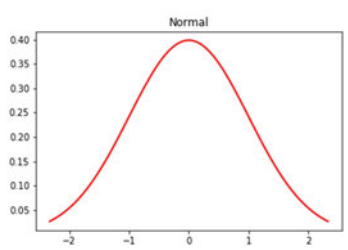
A. Continuous Distributions



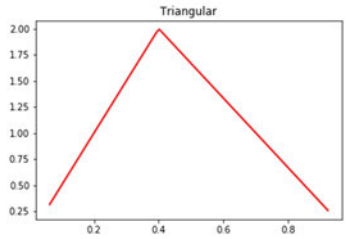
The exponential is often used to represent decay, where the majority of values are in the lower range (near zero) and has a tail with larger losses. It has only one parameter, the mean.



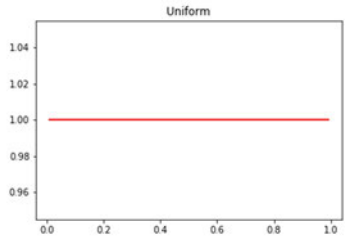
The lognormal distribution, unlike the normal distribution, is bounded on the left side by zero (so only positive values) with a tail similar to the exponential distribution. It has two parameters: a mean and a standard deviation.



The normal distribution is a symmetrical bell-shaped curve, with minimum values that are not bounded by zero. It has two parameters: a mean and a standard deviation.

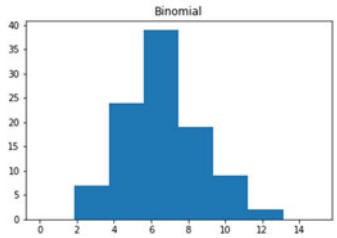


The triangular distribution is bounded by a minimum and maximum value. The tip of the triangle is the mode (or the highest frequency value). Therefore, the probability that a random value that is chosen near this tip is the highest. It has three parameters: a mininum, a maximum, and mode.

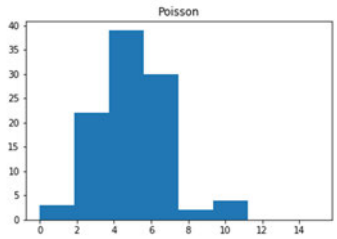


The uniform distribution is bounded by a minimum and maximum. The probability that a random value is selected between the minimum and maximum is the same. It has two paramters: a minimum and maximum value.

B. Discrete Distributions



The binomial distribution is a discrete distribution where the random variable chosen (the output) is a **positive integer** and is used in the **Outcome** portion of the bowtie. It is a probability distribution of the number of successes in a sequence of *n* independent trials based on a probability of success (*p*). In the bowtie, the *n* would represent the TEF of each scenario and the *p* is the outcome percentage.



The poisson distribution is also another discrete distribution where the random variable chosen is a **positive integer** and is used in the **Driver** portion of the bowtie since the Trigger Event Frequency should be a positive integer number instead of a number with decimals (which would be the output of continuous distributions). It is used to describe the number of "events" in some time interval (i.e., annual).

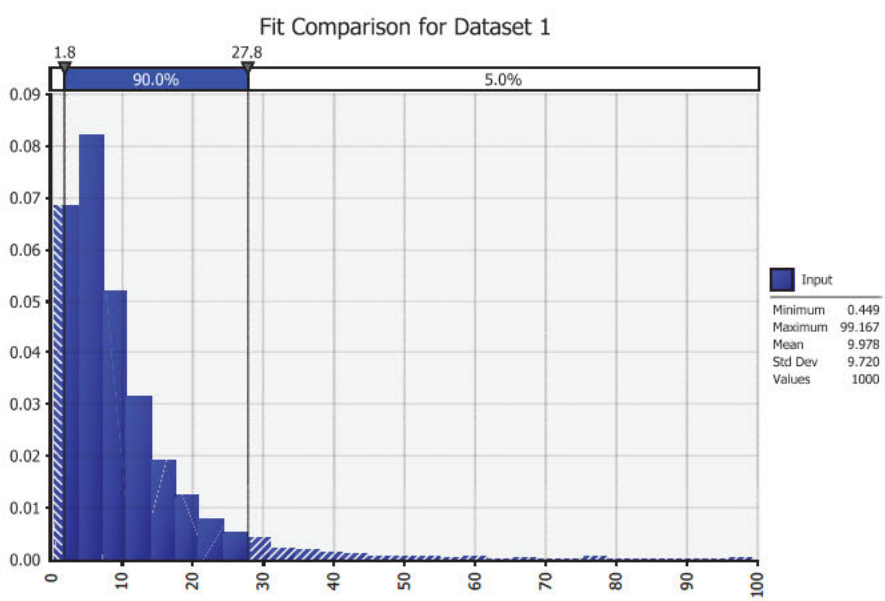
III. Distribution Fitting Process

This section describes how distributions were chosen for the consequences modeled in each risk chapter. The specific distributions used within each chapter are provided in each chapter's respective workpapers.

Most statistical software packages include a "distribution fitting function" which evaluates a list or time series of numbers (e.g., historical data) and recommends a distribution type which best fits the inputs. The @RISK simulation software includes this type of function. SCE used this distribution fitting function as a starting point in determining the appropriate distribution to use for each consequence. We then evaluate the results and make adjustments as necessary to best reflect the risk being evaluated.

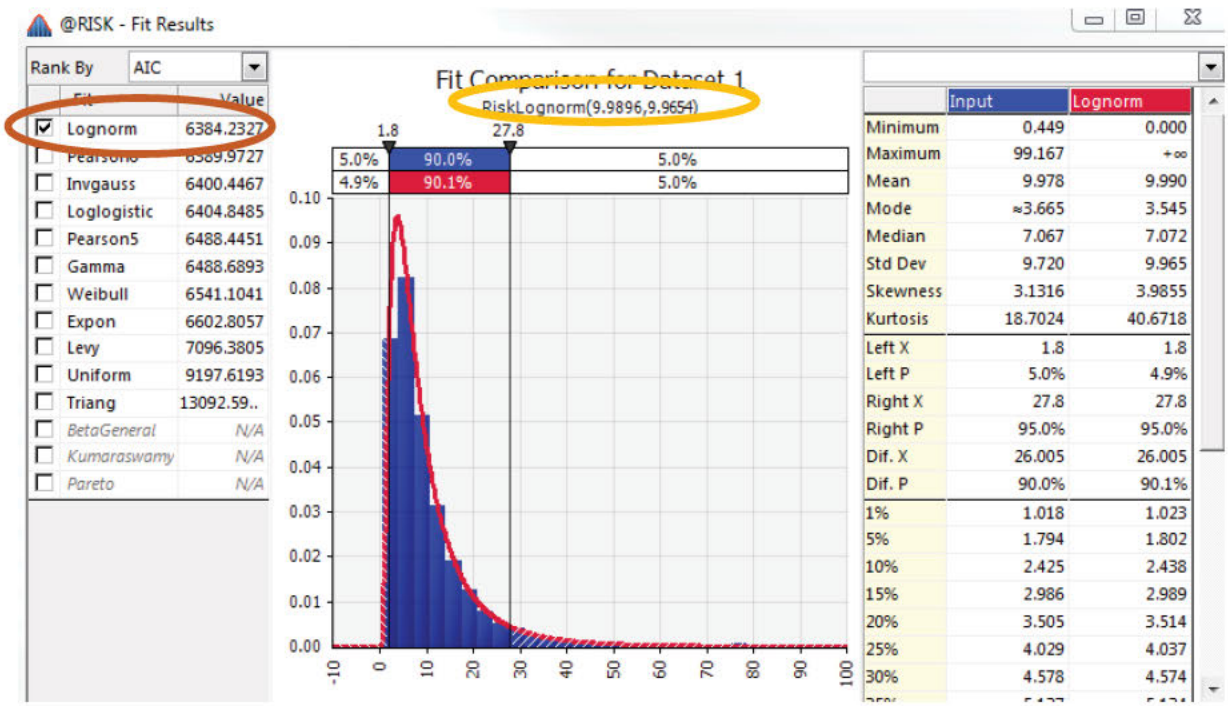
The distribution fitting function is illustrated in the following example: 1,000 events resulting in CMI are provided to the model – these data are plotted as a histogram in Figure III-1. There are a few key statistics displayed on the right-hand side of the histogram, such as the mean (which is ~10).

Figure III-1 – Histogram plot of sample data



We then run the @RISK distribution fitting function to determine the best fit distribution and associated parameters to model this data. A screenshot of this function is shown in Figure III-2.

Figure III-2 – Sample Distribution Fitting Function



The @RISK function chose the Lognormal distribution as the best fit (see top left section where Lognorm is at the top of the list). In addition to choosing the best fit distribution type, the function also chooses the best fit distribution parameters (such as mean and standard deviation).

IV. Appendix 1: Simulation Example

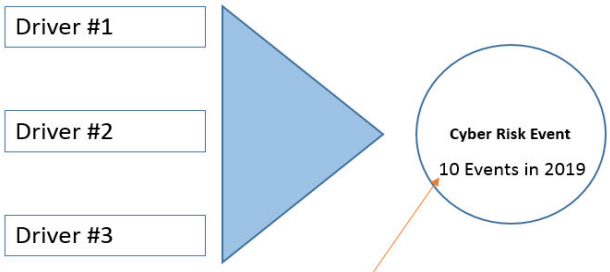
This appendix provides an illustrative example of how the risk model works.

Step 1

Drivers - Inputs

Illustrative Example

Driver(s) will determine the frequency of the Risk Event (i.e. Cyber intrusion) per year



If the ***average*** yearly frequency of the "Cyber Risk Event" is 10 in 2019, then the sum of the frequency for Driver(s) #1 + #2 + #3 must also be 10 in 2019.

	2019	2020	2021	2022
Driver #1	5	5	3	7
Driver #2	3	6	2	2
Driver #3	2	7	1	3
Risk Event Count	10	18	6	12

Inputs

Each Driver is independent (no correlation)

Step 2:

Driver –> Risk Event Calculation

For each Driver and Monte Carlo trial, draw a random number from a Poisson distribution (outputs an integer number) given the frequency.

See slide 1, 2019 Column for Driver Frequency

Sample draws for 2019

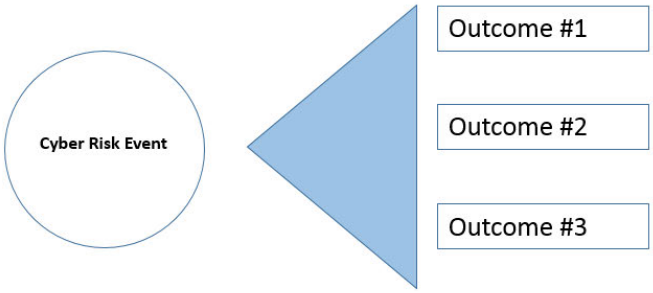
Trials	Driver #1 Freq : 5	Driver #2 Freq : 3	Driver #3 Freq : 2	Total count of Risk Event
1	7	2	1	10
2	5	5	3	13
3	5	2	3	10
4	3	0	2	5
5	6	1	2	9
....	...	...	...	...
10,000	4	4	1	9
Average	5	3	2	10

Random Draws

Step 3:

Outcomes - Inputs

Given that ***x*** "Risk Events" have been triggered for a given year (see previous slide), determine how many instances of each outcome will occur



The yearly percentage of Outcome(s) #1 + #2 + #3 will be equal to 100%

%	2019	2020	2021	2022
Outcome #1	60%	40%	10%	25%
Outcome #2	30%	40%	10%	25%
Outcome #3	10%	20%	80%	50%
TOTAL	100%	100%	100%	100%

Inputs

Step 4:

Risk Event -> Outcome Calculation

Given the "Total count of Risk Event" for each trial, draw from a binomial distribution for each Outcome given its probability of occurring. A binomial distribution is used because it takes as input A) sample size and B) probability of success.

Trials	Total count of Risk Event (from slide 2)	Outcome #1 Occurrence: **60%**	Outcome #2 Occurrence: **30%**	Outcome #3 Occurrence: **10%**	Total
1	10	7	4	0	11
2	13	9	4	2	15
3	10	5	2	3	10
4	5	4	2	0	6
5	9	4	2	1	7
....	...	...	...	...	
10,000	9	7	4	0	11
Average	10	6	3	1	10

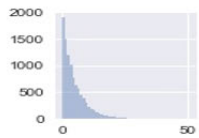
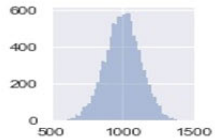
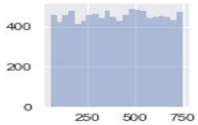
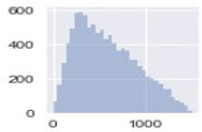
For trial #1, Outcome #1 will happen **7** times given that the Risk Event occurs 10 times in a particular year

Note: The total of each row will not always equal the Risk Event count of each trial. However, on average, it will (see bottom row).

Step 5:

Outcome -> Consequence Mapping

Each Outcome is mapped to Consequences. This mapping is associated with a distribution type (i.e. normal, uniform, etc..) and the distribution parameters (such as mean, standard deviation, etc...). The selection of distribution will primarily be based on historical SCE or other utilities data, informed or potentially adjusted by SME input. These distributions are based on a ***per event*** basis.

	Financial	Reliability	Serious Injury
Outcome #1	[NONE]		
Outcome #2			
Outcome #3			[None]

Step 6:

Financial Consequence Calculation ($)

Financial : Based on the mapping table (step 5), draw from the appropriate [Outcome | Consequence] distribution type the number of times per each outcome/trial and then sum the numbers.

Trial	Total count of Risk Event	Outcome #1	**Financial ($) Consequence for Outcome #1**	Outcome #2	**Financial ($) Consequence for Outcome #2**	Outcome #3	**Financial ($) Consequence for Outcome #3**
1*	10	7	**N/A (See upper left cell in Slide 5)**	4	1,077	0	0
2	13	9		4	1,074	2	491
3	10	5		2	528	3	786
4	5	4		2	497	0	0
....	...	...		...	...	...	
10 K	9	7		4	1,317	0	0

*** See first row from step 4**

Financial Consequence #2, Trial 1: Draw 4 numbers from the Normal Distribution associated with Outcome #2 and Financial Consequence [See step 5]. The 4 numbers are 259, 277, 262, 279. The sum of these numbers is **1,077**.

Financial Consequence #3, Trial 2: Draw 2 numbers from the Uniform Distribution associated with Outcome #3 and Financial Consequence [See step 5]. The numbers are 165 and 326. The sum of these numbers is **491**.

Step 7:

Reliability Consequence Calculation (CMI)

Reliability: Based on the mapping table (step 5), draw from the appropriate [Outcome | Consequence] distribution type the number of times as listed and then sum the numbers.

Trial	Total count of Risk Event	Outcome #1	**Reliability (CMI) Consequence for Outcome #1**	Outcome #2	**Reliability (CMI) Consequence for Outcome #2**	Outcome #3	**Reliability (CMI) Consequence for Outcome #3**
1*	10	7	3,869	4	3,695	0	0
2	13	9	5,802	4	3,937	2	491
3	10	5	3,444	2	1,168	3	786
4	5	4	2,925	2	2,010	0	0
....	...	...		...	...	...	
10 K	9	7	3,666	4	3,797	0	0

*** See first row from step 4**

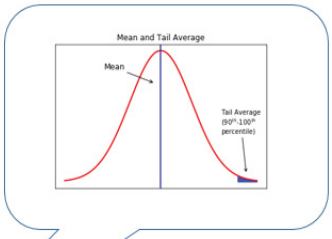
Reliability Consequence #1, Trial 4: Draw 4 numbers from the Triangle Distribution associated with Outcome #1 and Reliability Consequence [See step 5]. The 4 numbers are 525, 564, 1000, 836. The sum of these numbers is **2,925**.

Reliability Consequence #2, Trial 3: Draw 2 numbers from the Normal Distribution associated with Outcome #2 and Reliability Consequence [See step 5]. The numbers are 1,067 and 101. The sum of these numbers is **1,168**.

Step 8:

Aggregating Consequences

- Calculate the Mean and Tail Average (TA) from the output (green columns in slides 6,7) for each Consequence and Outcome.
  - Mean: Average the output
  - TA: Average the worst 10% of the output
- Overall Mean
  - Add the mean for each of the outcomes associated for each consequence
- Overall TA
  - Add the TA for each of the outcomes associated for each consequence



	Financial	**Reliability**	**Serious Injury**
Outcome #1	[None]	Mean = 1,500 TA = 3,000	Mean = 10 TA = 20
Outcome #2	Mean = 1,500 TA = 2,500	Mean = 5,000 TA = 6,000	Mean = 20 TA = 25
Outcome #3	Mean = 3,000 TA = 5,000	Mean = 800 TA = 2000	[None]

Overall Mean and Tail Average

	Financial	**Reliability**	**Serious Injury**
Mean	**4,500** = 1,500 + 3,000	**7,300** = 1,500 + 5,000 + 800	**30** = 10 + 20
Tail Average	**7,500** = 2,500 + 5,000	**11,000** = 3,000 + 6,000 + 2,000	**45** = 20 + 25

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Safety Culture & Compensation Policies Tied to Safety

Chapter 3

Rosemead CA
November 15, 2018

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I. Safety Culture and Performance

Southern California Edison (SCE) is committed to delivering safe, reliable, affordable and clean energy to its customers. Safety is our top priority, and part of that is making sure that we empower employees with the knowledge, motivation, and means to make safe choices. SCE is also committed to collaborating with our contractors to strengthen safe work practices and educating the public to avoid hazards associated with our electrical grid.

SCE has markedly improved in some aspects of safety performance. Our Days Away, Restricted or Transferred (DART)[1] rate is steadily declining. However, serious injuries and fatalities continue to occur. The majority of serious injuries and fatalities over the past decade have occurred because of human error, and not the failure of equipment, policies, or programs. Based on the results of our safety culture assessments, we believe that the next step in improving safety requires improving our underlying culture. This conclusion is also supported by industry success stories and academic literature spanning other industries and disciplines.

Research and standards published by safety governing bodies such as the Institute of Nuclear Power Operations (INPO) and the Occupational Health and Safety Administration (OSHA) establish that a strong safety culture is a prerequisite to positive safety performance. An organization's safety culture refers to a shared set of beliefs, rules, and values around safety upheld by an organization and its employees. To better understand our current safety culture and measure its ongoing improvement, SCE is leveraging a research-based safety culture maturity model. This maturity model is comprised of five sequential levels that correspond with observable safety behaviors. These five levels are described below and illustrated in Figure I-1.

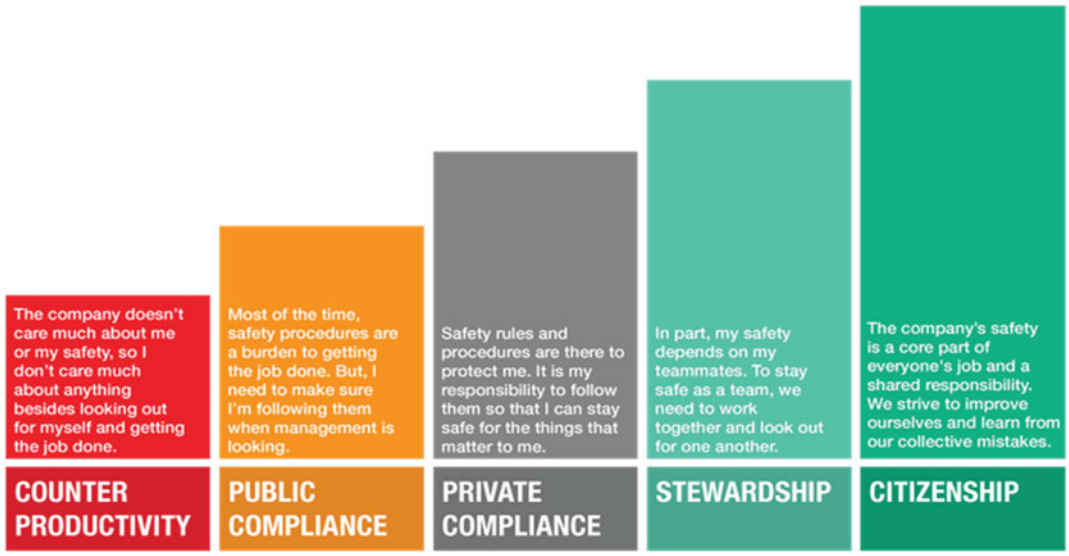
1. Counter Productivity – "safety doesn't matter much around here";
2. Public Compliance – "follow procedures when management is looking;"
3. Private Compliance – "I value my safety, so I follow the rules;"
4. Stewardship – "to stay safe as a team, we need to look out for one another;"

[1] DART means "days away, restricted or transferred." DART is a safety metric used by the Occupational Safety and Health Administration (OSHA) to show how many workplace injuries and illnesses caused the affected employees to remain away from work, restricted their work activities or resulted in a transfer to another job as they were unable to do their usual job within a calendar year. The DART rate helps the employer identify safety items and issues in the workplace.

5. Citizenship – "we strive to improve ourselves as individuals and together as a company."

Each level of safety behavior maturity in Figure I-1 below aligns with particular characteristics of organizational safety culture, including employee values, beliefs, and attitudes. As a result, by observing employees' behaviors and other tangible signs of safety culture, SCE can determine its level of safety culture maturity and develop specific strategies to improve.

Figure I-1 – Safety Culture Maturity Model



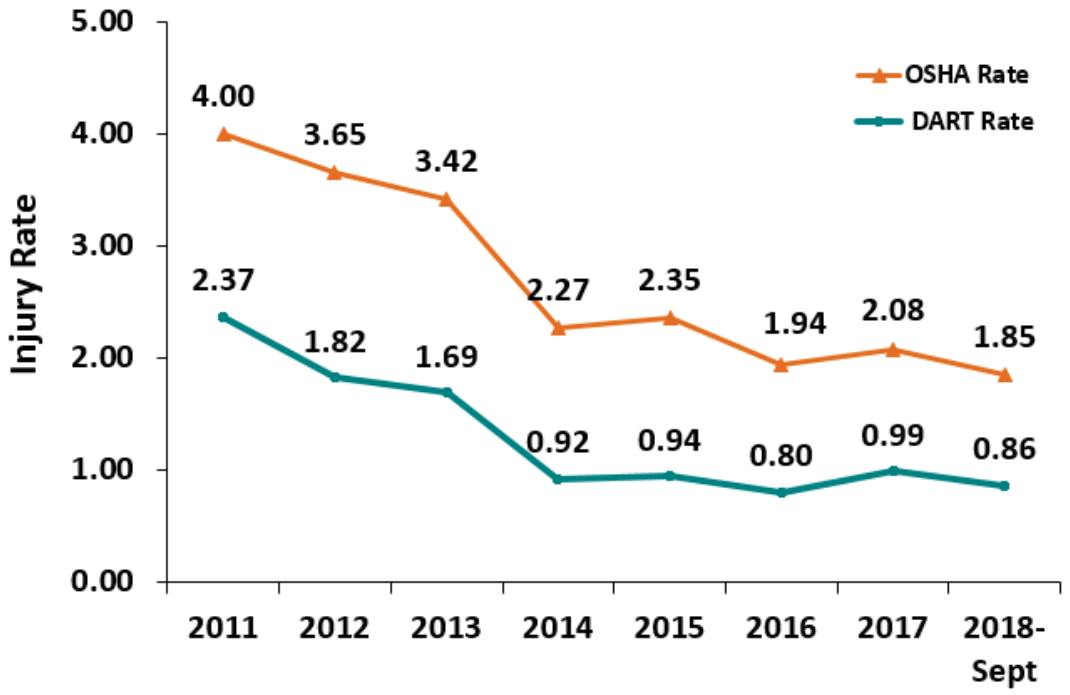
In this chapter, we discuss our safety efforts over the last four years. Within those four years, the first three focused on fostering a strong cultural foundation around programs and tools while preparing leaders to transform the safety culture in year four. The chapter will then look ahead to ongoing and planned efforts to proactively identify and mitigate safety risks to SCE employees, contractors and the public. SCE intends to continue evolving our safety culture to one where safety is perceived as something all employees want to do, instead of something they have to do. This will foster safer mindsets, attitudes, and ultimately behaviors. This is a long-term and continuous process; SCE is committed to making sure that our employees, contractors, and all members of the public in our service territory are safe.

A. We Have Already Significantly Improved in Some of Our Safety Outcomes

1. Employee Safety

SCE has seen dramatic improvements in our safety results. As shown in Figure I-2 below, based on current, year-to-date statistics, since 2011, SCE achieved a 64 percent improvement in employee safety performance, as measured by our DART rate. Our OSHA rate also significantly improved over that same period by 54 percent. Even with improvements, we have some distance to go to achieve and maintain an injury-free workplace.[2] The primary causes for the injuries we are currently seeing are falls and electrical flashes.

Figure I-2 – Employee DART and OSHA Rates, 2011-2018



2. Contractor Safety

In 2015, SCE implemented a contractor safety program, which established four key changes in how we approach contractor safety.

1. The program spearheaded the practice of SCE holding contractors to a standard of safety performance consistent with the standard to which we hold employees or an equivalent standard.

[2] Our immediate goal is to achieve first quartile performance in safety.

2. We expect contractors to follow SCE safety requirements and periodically assess compliance through field observations and Contractor safety Quality Assurance Reviews (CSQARS) conducted by our SCE field representatives.
3. We have strengthened our oversight and monitoring of contract personnel through multiple safety engagement activities. Examples include: pre-job qualification and safety briefings, on-the-job monitoring, post-job safety evaluations, and SCE-sponsored contractor safety forums.
4. We implemented measures to improve visibility and oversight concerning contractor safety incidents. Contractor safety incidents are now recorded in SCE's safety incident management system, reviewed on the Edison Safety Scorecard, and analyzed so that SCE can complete appropriate root cause analysis and develop actions to prevent future events.

We experienced 18 serious contractor injuries through September, 2018. These were primarily due to falls, and body parts caught in, under, or between equipment. Unfortunately, we also experienced two contractor fatalities through September, 2018 as a result of an induction incident and a fall during tree trimming activities. We will continue to refine our contractor safety program to better and more proactively identify and mitigate factors that lead to serious injuries and fatalities.

3. Public Safety

Protecting the public is central to our mission to provide safe, reliable, and clean electricity. Table I-1 outlines the trend of public serious injuries and fatalities reported to the CPUC from 2014 through September 2018; the primary cause of these incidents was contact with power lines.[3,4]

We have three key approaches to improve our Public Safety outcomes.

1. Programs that evaluate, maintain, and replace infrastructure. These programs help mitigate the risk of system failure contributing to a public safety incident. An example of this is our Overhead Conductor Program, discussed in Chapter 5, Contact with Energized Equipment.

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[3] Incidents are defined as CPUC-reportable incidents involving a fatality or a serious injury as defined by Cal/OSHA. A Cal/OSHA serious injury is defined as any injury or illness (including death), which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an individual suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement.

[4] Please refer to WP Ch. 3, pp. 3.31 – 3.38 (*2014 – 2018 CPUC Reportable Public Fatality & Serous Injury Events)*

2. Outreach programs that provide education and essential information to the public, including billboards, radio campaigns, mailers, and television campaigns in multiple languages. Public Outreach programs are also discussed in Chapter 5, Contact with Energized Equipment.
3. Investigating major incidents to implement improvements and proactively mitigate possible similar incidents.

Table I-1 – Public Safety Incidents, 2014- 2018

Public serious injuries & fatalities *due to system failures*					
	2014	2015	2016	2017	2018 YTD Sept
Public Fatalities due to System Failure	0	0	0	1	0
Public Serious Injuries (Cal OSHA) due to System Failure	0	0	0	1	0
Total public serious injuries & fatalities *reported to CPUC*					
	2014	2015	2016	2017	2018 YTD Sept
Public Serious Fatalities	11	4	6	4	6
Public Serious Injuries (Cal OSHA)	20	12	8	10	8

B. SCE Developed and implemented a Safety Roadmap in 2015 After Conducting an Enterprise-Wide Assessment of Safety Culture

In 2014, SCE conducted an enterprise-wide Safety Culture Assessment. To address the opportunities for improvement identified in this assessment,[5] SCE developed an Enterprise Safety Roadmap based on assessments, recommendations, and the collective input of senior leaders representing all organizational units across the company. The resulting roadmap focused on 27 initiatives spanning 2015 through 2016. These initiatives were targeted at key areas identified in the assessment as gaps in the SCE culture, and are listed and described in Table I-2 and Table I-3 below.

[5] *Id.*

Table I-2 – Enterprise Safety Roadmap Initiatives, 2015

	Initiative	Description
Governance	1 Safety Governance	Launch an Enterprise Safety Governance Structure that ensures alignment and governance over safety across the Enterprise.
	2 Communication Strategy	Develop and implement a communication strategy that creates a common messaging platform for all safety communications, identifies protocols and governance, and identifies corporate and OU responsibilities for safety communications.
	3 Corporate Safety Goal	Develop a corporate safety goal that is multi-tiered and makes safety a required part of Short Term Incentive Program.
	4 Safety PDP Goals	Develop a common safety PDP goal for all leaders to complement the common safety PDP competency.
	5 Safety Scorecard	Develop a safety scorecard with leading and lagging indicators on worker (employee and contractor) and public safety.
	6 Safety Organization & Operating Model	Identify and implement a safety organization and operating model that will be effective and efficient in support of injury-free.
Leadership	7 Executive Safety Engagement	Develop and deliver safety engagement soft skills training to executives to ensure they are able to articulate the company safety vision and lead safety improvement.
	8 Safety Leadership Development	Develop and deliver safety leadership training that ensures all Edison leaders have strong and consistent safety leadership skills.
	9 Safety Staff Qualifications & Training	Define minimum qualifications for safety specialists and deliver training that covers their role, technical safety programs, and field investigation techniques.
	10 Leaders Roles & Responsibilities	Develop specific safety expectations for leaders to be reinforced in training and with PDP goals.
Worker Engagement	11 Observation Program	Develop and implement an integrated companywide observation program that allows for customization by work type and retires existing OU programs.
	12 Safety Congresses & Teams	Develop and implement an Enterprise plan for safety congresses and teams to improve their effectiveness and impact.
	13 Safety Recognition Program	Develop and implement an Enterprise safety recognition program that defines safety behaviors and accomplishments core to achieving the safety vision and a program to consistently reward and reinforce those behaviors and accomplishments.
	14 High Hazard Skills Training	Develop and deliver high hazard skills training for craft employees beyond apprenticeship training.
	15 Safety Partnership with Union Leadership	Continue to strengthen the safety partnership with union leadership to ensure alignment on safety vision, desired values, activities, and initiatives.
	16 Contractor Safety Program	Develop and implement Contractor Safety Program that ensures clear safety expectations for contractors that align with expectations for employees.
Safety Systems	17 Incident Management & Investigation	Develop and implement an Incident Management Standard that ensures consistency in how incidents are reported and investigated, and a consistent process to classify and track incidents that are or have potential for serious injury or fatality.
	18 Injury Management & Return to Work	Benchmark injury management and return to work programs, processes, and procedures to identify opportunities for SCE.
	19 Safety Program Evaluation	Develop and implement a plan to ensure the effectiveness and compliance of corporate safety programs and OU implementation of those programs in preventing and mitigating incidents and injuries.
	20 Best Practice Sharing	Develop and launch best practice sharing mechanisms that leverage the Safety Governance Structure to share best practices between OUs and from external benchmarking.

Table I-3 – Enterprise Safety Roadmap Initiatives, 2016

	Initiative	Description
Worker Engagement	1 Safety Roles & Responsibilities	Share safety roles & responsibilities with all employees
	2 Health & Wellness	Incorporate health and wellness into safety
	3 Safety Observation Program	Improve effectiveness and utilization of enterprise-wide observation program and mobile app
Leadership	4 Safety Leadership Development	Define the role of safety for leaders in Edison's leadership philosophy (Vision, People, Accountability)
	5 Executive Safety Skills	Conduct safety skill building for executives
Safety Systems	6 Organizational Learning	Promote continuous learning for injury prevention
	7 Contractor Safety	Further integrate contractors into worker safety

We created an enterprise safety governance structure in 2015 to align the company on our safety direction and execute the Enterprise Safety Roadmap initiatives. It has since evolved to incorporate broader governance responsibilities over employee, contractor and public safety. This governance structure has three levels.

1. The Executive Safety Council (consisting of the CEO and his direct reports, and a senior leader representing EIX). The Executive Safety Council sets and monitors the enterprise safety strategy, reviews key safety incidents, and oversees the execution of safety initiatives;
2. The Senior Safety Council (consisting of executive and senior management across all organizational units). The Senior Safety Council is responsible for operationalizing the safety direction set by the Executive Safety Council and the execution of Safety Culture Transformation initiatives. The Senior Safety Council also identifies, monitors, and refines additional safety initiatives.
3. Operating Unit Safety Councils (consisting of the Operating Unit leadership and employee representatives). The Operating Unit Safety Councils are responsible for: (a) day-to-day execution of the safety direction set out by the Executive and Senior Safety Councils, (b) day-to-day monitoring of the 27 initiatives referenced above, and (c) identification of and follow-up action on safety issues. Within each OU, there are grassroots safety congresses and teams, where employees are empowered to identify and lead efforts to improve safety throughout the workplace.

As part of the Enterprise Safety Roadmap, we focused on clarifying the behavioral expectations for leaders and employees by creating a Safety Roles and Responsibilities guiding

document. The content of this document was then integrated into safety competencies and performance development criteria. Additionally, all executive leaders attended half-day workshops and six monthly training sessions to align on their role in improving safety within their groups; these leaders were equipped with tools to further catalyze and sustain the change within their respective organizations.

In 2016, the Executive Safety Engagement effort led to all executive leadership dedicating half a day in the field learning and practicing the skills necessary to better engage with field employees. This directly addressed one of the stronger themes from the 2014 assessment: that leaders needed to be visibly engaged with, learn from, and collaborate with our employees.

When assessing the effectiveness of these activities, the 2017 Safety Culture Assessment found that about 76 percent of participants believed that SCE's safety culture and leadership had improved over the last two years (2015 and 2016). While this improvement in cultural and leadership perceptions was associated with a general downward trend in DART (0.94 to 0.80) over the same time period, we understand that the relationship between safety culture and safety performance is not linear. However, as we continue to focus on aligning employees' safety values, attitudes and behaviors, we expect to see improvements in safety behaviors, and ultimately safety performance, over time.

C. In 2017 SCE Conducted an Assessment and Took Additional Steps on our Journey Toward Improving Our Safety Culture and Reducing Injuries

In the last two quarters of 2016, SCE conducted a desktop review with a safety culture consulting firm to begin planning for the 2017 Safety Culture Assessment. One of the key recommendations from the desktop review was to signal the importance of safety in the organization by modifying the organizational structure. This modification would have Corporate Safety operate as a separate department reporting directly to the CEO through the appointment of a senior safety executive. Shortly after this recommendation, a new executive position of Vice President of Safety, Security and Business Resiliency was appointed, reporting directly to the CEO. This new executive position functions as the Chief Safety Officer for the entire Company, and the executive selected for the position has extensive experience leading safety, training, and compliance programs and organizations in various organizations across SCE over the last 25 years.

Entering 2017, we recognized the progress we had made, but continued to be dissatisfied with the rate of injuries across the company. To evaluate our situation, we asked the safety culture consulting firm that conducted the 2016 desktop review to now conduct a comprehensive Safety Culture Assessment. The survey asked employees questions about their views on the safety climate at the organizational and team level, contractor safety interactions, safety leadership, training quality, safety communications, safety performance, and strengths and weaknesses in learning from errors and speaking up when warranted.

Simultaneously, to supplement the information provided in the surveys, the vendor also conducted an Onsite Safety Evaluation across a geographically and organizationally representative sample. This Onsite evaluation involved experienced consultants conducting interviews, focus groups, and job observations. These activities were conducted with a broadly representative group of employees, from senior leadership positions to field employees. Job observations included field observations, and participation in regular meetings and job site reviews.

One of the core findings of the Safety Culture Assessment was based on the safety culture maturity model (see Figure I-1); SCE was assessed to be at the *Public Compliance* level of safety culture maturity, with some elements emerging of a *Private Compliance* safety culture.

In a Public Compliance safety culture, safety is viewed as something imposed upon the employees by "management" or "the company" (or some outside enforcing agency, such as OSHA), but it is necessary to stay out of trouble with management and/or stay in compliance with regulations. In Public Compliance cultures, safety is usually thought of in terms of "just follow the rules," with primary attention being paid to: (1) complying with safety procedures, (2) avoiding high-risk events, and (3) reducing safety lagging indicators.

In a Private Compliance safety culture, the following characteristics are often observed:

1. Safety is thoughtfully considered by all leadership as a critical means to achieving the company's goals;
2. Safety is seen as a worthwhile personal investment of time and effort by the workforce;
3. Individuals are committed to completing work safely and supporting one another to meet safe production goals; and
4. Individuals value staying safe at work and outside of work, whether in public view or not.

Beyond the safety maturity finding, the Safety Culture Assessment also identified the following themes as specific areas of opportunity:

1. "As My leader goes, so goes the culture"
2. "I speak up…but it depends on who it is and what they are doing"
3. "Regulation not Risk"[6]
4. "I can give my feedback, but I doubt anything will be done with it"
5. "Protect the business, then its people"
6. "Safety is Overkill"

The conclusions and recommendations of this assessment were consolidated into a Safety Culture Transformation program.[7] This program is responsible for developing, implementing, and sustaining discrete initiatives to address specific findings and evolve our safety culture to one of Private Compliance.

The Safety Culture Transformation Program comprises six main focal areas, targeted at inclusively strengthening culture:

1. Common Understanding of Safety Culture Change
2. Leadership and Talent Management
3. Safety Communications
4. Hazard Awareness and Risk Management
5. Safety Data Strategy
6. Safety Governance, Structure and Programs

One of the core tenets of SCE's overarching cultural approach is that leadership drives culture, and a strong safety culture is integral to cultivating and sustaining safe attitudes, values and behaviors. Our second core tenet rests on the fact that recognizing hazards and mitigating risks are skillsets that can be trained and honed over time. While a strong culture will foster the desire and decision-making framework needed to make the right safety choices, there are also cognitive tools that will equip our employees with the specific knowledge and skills to recognize and effectively mitigate hazards.

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[6] This represents an organizational focus on reporting, documentation, rules, policies, and procedures which has cultivated an over-emphasis on meeting the minimum standard. The workforce is predominantly focused on simply upholding the letter, rather than the spirit, of the law.

[7] Please refer to WP Ch. 3, pp. 3.1 – 3.30 *(Safety Culture Transformation Roadmap)*.

Our Leadership and Talent Management approach focuses on three main areas. First, training leaders in cognitive behavioral principles that give them the tools to create an environment where safety is tangibly and psychologically valued. Second, developing and aligning competencies to the overarching safety culture, and then assessing and addressing leadership competency gaps. Third, aligning talent pipeline processes (such as recruitment, selection, and succession planning) with core safety competencies and values.[8]

This strategy of developing effective leaders, shifting employee safety mindsets and providing consistent programs, directly addresses the factors integral to creating and sustaining a strong safety culture.

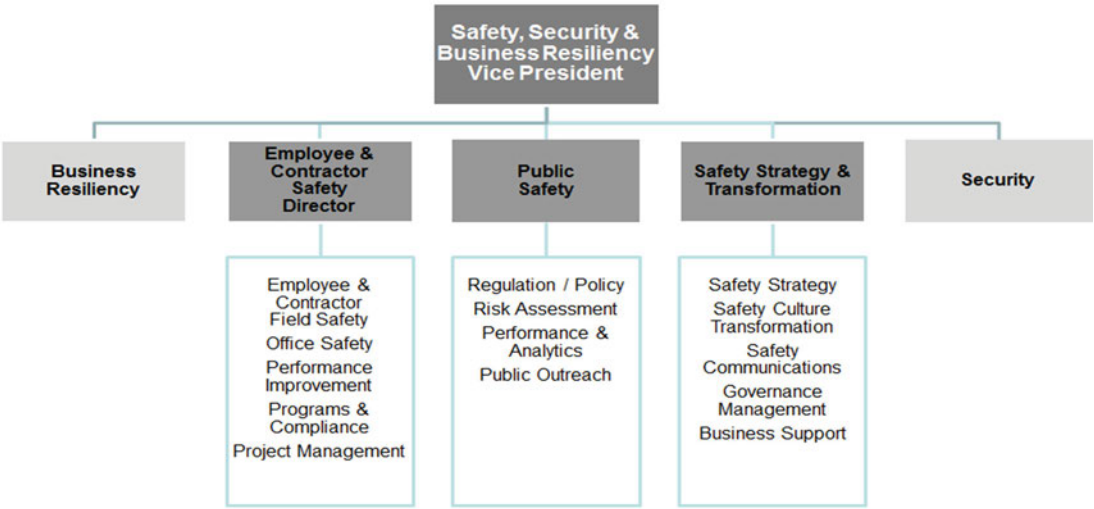
D. Improving our Culture Involved Changing Our Organizational Structure

Our Safety Culture Transformation is moving the Company towards a culture of safety ownership, where each of us, as individuals, chooses to stay safe. As discussed above, in 2017 SCE created an executive position, Vice President of Safety, Security and Business Resiliency, that reports directly to the CEO. Also, SCE strategically evaluated how safety is organized and managed. After reviewing best practices from high-performing organizations (both internal and external), it appeared that a centralized organization could accelerate our safety culture transformation.

On October 1, 2018, we implemented the Edison Safety organization (structure outlined in Figure I-3 below). This organization is led by the Vice President of Safety, Security and Business Resiliency, and consolidates several existing safety organizations across Transmission and Distribution, Generation, Customer and Operational Services and Corporate Health and Safety. The new Edison Safety organization is dedicated to operationalizing the Edison Safety strategy with an increased focus on Public Safety.

[8] Please refer to Chapter 7 – Employee, Contractor & Public Safety for additional information on the Leadership and Talent Management approach.

Figure I-3 – 2018 Edison Safety High Level Organizational Chart



The new organization promotes consistent safety messages, and improves efficiency through the allocation of safety resources across the company. Centralizing the safety organization will also improve our analytical efforts. We are constantly evaluating both leading and lagging indicators to assess our safety performance. We also compare ourselves to peer company benchmarks to evaluate our progress. We have actively pursued a strategy of using predictive analytics.

By focusing on operational, safety and external data to develop predictive models to identify risk factors, we should be able to develop more timely and targeted interventions. In 2018, we are implementing a new Safety Dashboard that will give us better visibility to key statistics and indicators, thereby improving our monitoring capabilities.

Our efforts here align with the longer-term strategies that we can focus on in a centralized organization. This will include:

1. Consolidating safety data systems, using new and improved software tools. With better data and better visibility, we can better manage safety outcomes.
2. Applying consistent classification and documentation processes and criteria across the company. This will improve the volume, consistency and the quality of the data we will have.
3. Using consistent and rigorous methodologies for investigations and documentation.
4. Fostering adequate resourcing.

The Vice President of Safety, Security and Business Resiliency is also responsible for providing comprehensive safety updates to the Board of Directors. This includes all aspects of safety, including conveying results for employee, contractor and public safety; reviewing major safety incidents; evaluating our ongoing safety efforts; and identifying emerging issues.

E. Our Path Forward is Through Improving our Safety Culture

At SCE, considerable progress has been made in safety outcomes and in raising the workforce's safety consciousness. However, we recognize that our past strategy of focusing on awareness campaigns has probably run its course. To transition to a more mature safety culture, we must advance our collective mindset about safety from being something that we have to do, to something that we want to do.

The Employee, Contractor & Public Safety chapter explains the Safety Culture Transformation program in considerable detail, and describes how this program will address some of the Company's key safety risks.

II. Compensation Policies Tied to Safety

A. Introduction to Compensation

Safety is SCE's number-one priority for our workers, for our customers, and for the communities we are privileged to serve. To foster a strong safety culture at SCE, we must use a multifaceted strategy. An important component of this strategy is to reward those who move the safety culture forward in a positive direction. We also tie certain aspects of compensation to how the Company performs in the safety arena.

As a result, SCE incorporates safety into its compensation policies and puts much of this reward at risk, depending on Company and individual performance in this area. This chapter will describe: (i) the structure of compensation for SCE's employees, including the role that safety plays in SCE's fixed and at-risk compensation, and (ii) how safety metrics included in at-risk compensation are established and evaluated.

B. Overview of Compensation

Figure II-1 below provides a general overview of SCE's total compensation structure, broken out by "Fixed" and "At-Risk" categories.

Figure II-1 – SCE Total Compensation Structure

Compensation Category	Compensation Type	Eligibility	
		Non-executive	Executive
Fixed	Base Pay	√	√
	Benefits (Retirement):		
	401(k) Savings Plan	√	√
	Qualified Retirement Plan	√	√
	Non-Qualified Retirement Plan		√
	Benefits (Health & Welfare)	√	√
	Benefits (Disability)	√	√
At-Risk	Variable Pay:		
	Short-term Incentive Plan (STIP)	√	
	Executive Incentive Compensation Plan (EIC)		√
	Long-term Incentive Plan (LTI)		√

Generally, SCE's total compensation (including retirement and benefits) consists of two distinct categories — "fixed" and "at-risk" compensation. The compensation categories and their connection to safety performance are explained further in the following sections.

C. Fixed Compensation

Base pay, expressed as an hourly rate of pay for non-exempt employees or as ongoing salary for exempt employees, represents the fixed component of pay. Base pay recognizes the ongoing performance, skills, competencies, and knowledge of job responsibilities of SCE's employees. Base pay levels are evaluated through annual assessments and yearly individual performance reviews. Unlike variable pay, base pay amounts are generally not subject to adjustment during the applicable year based on employee or Company performance against annual Company goals. As such, this compensation type is not considered at risk.

Another aspect of fixed pay is the package of core benefits offered by SCE to its employees, which may be based on their hire date. This package includes health and welfare benefits (i.e., medical, dental, and vision plans, and life insurance), the 401(k) savings plan, retirement plan, and disability benefits. Base pay currently represents approximately 92 percent of non-executives' cash compensation, which includes variable pay. For executive employees, base pay currently constitutes approximately 53 percent of their cash compensation.[9]

1. How Safety Factors Into Fixed Compensation

The base pay of non-represented employees, including all executives and the Chief Executive Officer (CEO), is set each year by annually evaluating each individual's performance and examining where that employee's base pay falls compared to market data. We update market data annually for executive positions and biennially for non-executive positions.[10]

Performance evaluations include individual performance goals, plus goals targeted toward adherence to and promotion of Company values[11] and competencies. **Performance goals** may include safety-related objectives specific to an employee's job function. **Values** are the principles that guide what we do and the foundation for how we do it. One of SCE's values is Safety, and the following are guiding behaviors expected of each employee:

- Acts as a safety culture leader

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[9] This represents an average for SCE executives. The percentage is based on preliminary, unaudited numbers.

[10] In years where non-executive, individual jobs are not market-reviewed, the entire non-executive salary structure is adjusted for overall market conditions.

[11] SCE's company values include safety, teamwork, excellence, respect, integrity, and continuous improvement.

- Always works safely and stops unsafe work
- Coaches and recognizes safe work practices and behaviors
- Looks out for others
- Masters safety – understands the work and knows the safety risks
- Always visibly models and promotes safe behaviors

Each position has a defined set of **competencies**. These competencies are determined based on whether the position is in an individual contributor or leader role. All non-represented SCE employees have a safety competency – "Creates a Safety Culture" – designed to strengthen and sustain SCE's safety culture. The following are some of the ways that employees are expected to demonstrate their commitment to safety for themselves and their team:

- Demonstrates a genuine interest in the well-being and safety of others.
- Considers safety as the highest priority when making decisions.
- Proactively engages in safety programs and activities.
- Coaches others on safety, reinforcing desired behaviors and providing guidance to address unsafe behaviors.
- Demonstrates safety is a personal priority by aligning actions with the vision for an injury-free workplace.[12]
- Continuously deepens knowledge in work process risks and educates others in behaviors and methods that reduce risk.

At the end of each year, managers rate the performance of each participating employee in two ways: 1) how well they did in achieving their individual performance goals as well as the day-to-day responsibilities of their jobs; and 2) how well they demonstrated the Company's values and competencies, including the Safety value and "Creates a Safety Culture" competency. Managers then consider this performance rating when they are recommending an employee's annual increase to their base pay. While SCE's represented employees do not participate in the annual evaluation and merit increase process, leaders who establish work priorities for those employees are fully accountable for creating an environment where all employees understand that Safety is SCE's top priority.

[12] Applicable to employees who are individual contributors. SCE leaders are expected to demonstrate safety is a personal priority by developing and communicating a clear vision for an injury-free workplace.

D. At-Risk Compensation

SCE has two bonus plans: the Short-term Incentive Plan (STIP) for non-executive employees and the Executive Incentive Compensation Plan (EIC) for executive employees. SCE executive compensation also includes Long-Term Incentives. These at-risk compensation components are explained below.

1. Safety Affects Bonus Plans

Each position at SCE has an established bonus target opportunity. This opportunity may vary depending on: (1) how the Company performs against its annual goals; and (2) how the employee performs against his/her individual goals, values, and competencies.[13] A similar process is used for non-officer executive[14] target opportunities. The Company determines target opportunities for executive officers based on market data. Non-executives' bonus target opportunity ranges from 4 to 25 percent, and the executive bonus target opportunity ranges from 30 to 75 percent.

Company goals include metrics related to safety, reliability, customer satisfaction, and affordability. These metrics are established each calendar year by the Compensation Committee of the Board of Directors ("Compensation Committee"), which is comprised of independent directors.

SCE's 2018 goals incorporate Safety in three primary ways:

- First, SCE's 2018 goals include certain foundational goals. If any of these foundational goals are not met, the result can be a reduction to the overall Company goal performance score. The foundational goals can also be used in evaluating an individual employee's performance for compensation purposes. SCE's foundational goals incorporate metrics tied to worker and public safety, including the avoidance of (a) worker fatalities; (b) serious injuries to the public resulting from system failures.[15]
- Second, SCE's Safety goal evaluates the Days Away, Restricted, or Transferred (DART) rate, actions taken toward our Safety roadmap, and communications regarding safety incident cause evaluations. This goal carries a 10% payout weighting for the bonus plans.

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[13] Factor number two does not apply to non-exempt employees.

[14] "Non-officer executive" refers to an executive at the Director level.

[15] Please see below for a specific example where performance on the foundational safety goals led to the incentive compensation of certain senior executives being reduced.

- Third, SCE has a People goal that includes a metric to complete safety training for employees in high-hazard roles in the Transmission & Distribution operating unit.

SCE developed the 10% safety goal weighting for bonuses and the foundational goals to help incentivize safety engagement and ownership across all levels of the organization through a vested financial stake in safety performance. Safety is also imbedded in other goals, such as goals concerning reliability (which can affect public safety).

SCE sought to strike a balance here. On the one hand, it has been recognized by experts that overweighting compensation goals toward safety can actually be detrimental to safety. OSHA, for example, frowns on basing compensation on how many or how few injuries an enterprise has,[16] because it can lead to unintended consequences such as under-reporting of safety incidents and potentially have a chilling effect on employees speaking up about safety incidents. On the other hand, SCE needs to have its compensation goals reflect its priorities, and safety is the chief priority. The safety goals and weighting SCE has chosen represent that balance. Every employee sees and can be impacted by the emphasis SCE places on safety, but the compensation goals are not over-weighted so as to potentially encourage unwanted behavior.

Figure II-2 below shows SCE's 2018 performance goals and the target weightings for each. These apply equally to executives and non-executives.

[16] *See* OSHA Memorandum from Deputy Secretary Richard E. Fairfax re: Employer Safety Incentive and Disincentive Policies and Practices, (March 12, 2012), *available at* https://www.osha.gov/as/opa/whistleblowermemo.html. Please also refer to OSHA's discussion of incentives at section II.C, *available at* https://www.osha.gov/recordkeeping/finalrule/interp_recordkeeping_101816.html

Figure II-2 – SCE 2018 Performance Goals

SCE	Score		
Goal Category	**Threshold (Unmet)**	**Target (Met)**	**Stretch (Exceeded)**
Foundational Goals	If any of these occur, Compensation Committee may deduct points from the score		
Financial Performance	0-39	40	41-80
Operational and Service Excellence Safety Others (Customer Satisfaction, Reliability, Affordability and SONGS Decommissioning)	 0-9 0-14	 10 15	 11-20 16-30
Policy, Growth and Innovation	0-24	25	26-50
Diversity, People, and Culture	0-9	10	11-20
Total multiplier range	**0-99**	**100**	**101-200**

SCE determines Company goal performance by using three different measures for each category – Threshold, Target and Stretch – signifying the extent to which the goals were met in that area. Threshold refers to the minimum expected performance, while Stretch means goal performance has exceeded expectations for that area.

2. How SCE Establishes and Evaluates Safety Metrics for Compensation Purposes

Safety metrics that can affect compensation are developed by SCE's Corporate Health and Safety group, now known as "Edison Safety."[17] On an ongoing basis, the Utility Management Team (UMT) and the Edison International Managing Committee (EMC) review and may recommend changes to these metrics before they are approved by the Compensation Committee.

For the Safety target specifically, the key measurement involves the rate of "Days Away, Restricted or Transferred," also known as the "DART rate." To help determine this rate each year, the Company uses a combination of historical DART rate performance and expected performance based on top quartile industry benchmarks. Expected performance also takes into account the maturity of SCE safety culture initiatives and the realistic timeframe to achieve first

[17] Please *see* Chapter 7 (Employee, Contractor & Public Safety) for more information on this organization.

quartile performance, as determined by SCE's Corporate Health and Safety Group and approved by the UMT, EMC, and the Board of Directors.

In addition to the DART target, the 2018 Safety goal also includes: implementing actions in the Hazard Awareness and Risk Mitigation Safety Roadmap workstream, and performing and communicating effective cause evaluations on all fatalities, serious injuries, and potentially life-altering incidents.

SCE's foundational goals also include metrics tied to worker and public safety, including the avoidance of (a) worker fatalities; (b) serious injuries to the public resulting from system failures; (c) significant non-compliance events and significant disruptions; and (d) data breaches or system failures that adversely impact critical infrastructure or result in a breach of customer or employee data.

3. How Safety Affects Payout of Bonuses

At the end of each year, SCE evaluates its performance against the goals; the results are used as the basis for the bonus payout. Each goal category is assigned a score, the sum of which determines the multiplier (0 percent - 200 percent). The Compensation Committee approves and has discretion over the final scores. In the event one or more of the foundational goals are not met, Company management and the Compensation Committee may reduce or even eliminate the bonus payouts depending upon severity.

Last year, SCE's senior management demonstrated its commitment to have senior executives' compensation reflect safety performance. In 2017, SCE had two public safety incidents that senior management felt did not measure up to the foundational public safety goal. Each of the incidents involved a single individual. As a result of these two incidents, SCE's Chief Executive Officer and other senior leaders recommended to the Compensation Committee that a number of executives (including the Chief Executive Officer) receive a deduction to the individual performance factor of their bonus. It was a 10-point deduction for not meeting SCE's foundational public safety goal, meaning 10 percent of the 100-point target. This deduction was in addition to an 8-point deduction for missing SCE's goal to reduce employee injury rates.

The Compensation Committee agreed with the recommendation. The decision to reduce executive compensation was not made because of a Commission mandate or other regulatory requirement. Instead, it was made because SCE believes that it is appropriate to hold its senior leadership financially accountable for safety.

The recommended bonus payout for each employee and executive equals his or her target bonus, adjusted for the corporate modifier. Executives and exempt, non-represented, employee payouts are further modified by an individual performance modifier based on their overall performance for the calendar year. Awards for senior executive officers are also reviewed and approved by the Compensation Committee.

4. Long-term Incentives

SCE executive compensation also includes Long-Term Incentives (LTI). This is another compensation element that is considered at-risk, since the value of LTI depends on several factors, including multiple years of continuous employment, strong job performance at the executive level, and financial health of the Company. LTI includes non-qualified stock options, restricted stock units, and performance shares, with multi-year vesting periods from three to four years.

Each year, SCE performs a detailed market assessment of its executive workforce to assess each compensation package, including LTI. An executive's LTI is determined based upon the market data applicable for his or her position. The actual grant may vary based on an annual assessment of that individual's performance. The actual value of the award is determined after the vesting period based on Company performance.

While there is not an express safety metric embedded in LTI, the primary driver of LTI performance – long-term Company value – can be significantly impacted by SCE's safety performance. A safety issue could cause Company stock to underperform, resulting in reduced value of performance shares, restricted stock units, and stock options.

E. Safety Recognition Program

SCE's Safety Recognition Program supports positive safety behaviors by giving employees an opportunity to recognize and be recognized for demonstrating their commitment to advancing the Company's safety culture. All employees are eligible to, and encouraged to, actively participate in the program.[18]

Examples of the safety-related behaviors that are recognized include:

- Identifying previously unrecognized hazards;
- Participating in safety events and committees;

[18] Executives cannot actually receive awards under this program. The focus in the area of awards is to give such tangible rewards to non-executive employees.

- Stopping work after spotting unsafe conditions; and
- Preventing a serious incident from occurring among co-workers and/or the public.

F. Conclusion

As we said at the outset of this chapter, safety is SCE's number-one priority for our customers, for our workers, and for our communities. We are firmly committed to continuing to strengthen our safety culture. Our compensation policies are just one aspect of how we are doing this. Employees at all levels within the organization play a vital role in safety. During our performance evaluation process, each employee has safety-related competencies as part of their evaluation. Moreover, safety performance is expressly recognized in SCE's short- and long-term at-risk compensation, via our safety goal and foundational goal performance. The Company continues to evaluate and refine its safety metrics as our safety culture matures.

SOUTHERN CALIFORNIA EDISON®
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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Building Safety

Chapter 4

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

This chapter analyzes potential safety risks that buildings can pose to their occupants. SCE analyzed a variety of potential risk sources that could compromise the safety of a building for its occupants. This analysis resulted in three drivers: earthquakes, failure of electrical systems, and extreme wind.

Earthquakes can lead to both structural failures (e.g., wall, ceiling, and floor collapse) and non-structural failures (e.g., furniture falls over). Failure of a building's electrical systems can harm occupants or cause a fire within the building. Finally, extreme wind can propel objects through the air, with the risk that objects penetrate a building and injure occupants.

This chapter describes two compliance activities:[1]

- Fire Life Safety Compliance (CM1): This include systems and components focused on fire detection, suppression, and/or notification of building occupants.
- Electrical Compliance (CM2): These activities focus on safely installing, using, and maintaining building electrical systems.

In addition to the compliance activities, the chapter describes two controls:[2]

- Seismic Building Safety Program (C1): This include activities to identify, prioritize, and implement seismic improvements to occupied buildings.[3]
- Facility Emergency Management Program (C2): This includes activities to train employees on safety protocols during and after events such as an earthquake.

Finally, this chapter describes five potential mitigations:[4]

- Fire Life Safety Portfolio Assessment (M1): Assessing existing Fire Life Safety (FLS) systems and prioritizing potential improvements to these systems.
- Electrical Inspections (M2): Identifying and mitigating potential electrical failures on a preventative basis.

---

[1] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

[2] C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.

[3] SCE has excluded specific references to confidential material in this chapter related to seismic safety. If requested, SCE will take all reasonable measures to provide additional information to the Commission, its Staff, and interested parties, to help evaluate this report.

[4] M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report, and are addressed in Section IV.

- Wind-Borne Debris Protection (M3): Installing protective film on windows that increases the window's ability to resist shattering and penetration.
- Permanent Work(er) Relocation (M4): Relocating employees from an existing location to alternate locations, without replacement of the original location.
- Building Replacement (M5): Replacing an existing building with a new building.

SCE has developed three risk mitigation plans for consideration:

- The Proposed Plan continues existing seismic and emergency management programs while adding the new mitigations related to FLS systems and electrical inspections (M1 and M2, respectively).
- Alternative Plan #1 adds the new mitigations of permanent worker relocation and building replacement (M4 and M5, respectively) to the Proposed Plan.
- Alternative Plan #2 adds the new mitigation for wind-borne debris (M5) to the Proposed Plan (but does not add M4 and M5).

B. Scope

This chapter focuses on occupied buildings owned or leased by SCE. Table I-1 – Chapter Scope indicates the scope of the chapter.

Table I-1 – Chapter Scope

In Scope	• SCE buildings that are occupied (i.e., at least one employee has assigned seating). A total of 170 buildings meet this criteria (e.g., office buildings, service centers, garages, manned substations, etc.).[5] • Safety risks when the building or its components fail.
Out of Scope	• Buildings that are not occupied, such as unmanned substations, (these buildings do not pose a direct safety risk due to being unoccupied). • Occupied buildings at the San Onofre Nuclear Generating Station (SONGS).[6] • Safety risks not directly caused by the building (e.g., workplace violence or people performing unsafe acts) which are covered in other RAMP chapters.

C. Summary Results

Table I-2 below summarizes this chapter's baseline risk analysis, controls and mitigations contemplated, and portfolio results over the 2018 - 2023 period. Figure I-1Table I-1 illustrates the composition of consequences within the baseline risk. Sections II – VII of this chapter provide further detail and context for these results.

[5] Appendix A, *Summary of Buildings In Scope*, summarizes the number of buildings within each building category.

[6] As described in Chapter I, SONGS is generally out of scope for the RAMP report. However, SCE has provided a supplemental analysis to describe safety risks at SONGS, per the request of the Commission's Safety & Enforcement Division (SED). This is found in Appendix A – Nuclear Decommissioning of this RAMP report. SCE also notes that due to its status as a nuclear facility, SONGS is subject to safety compliance standards (e.g., per the Nuclear Regulatory Commission) that in some cases exceed the compliance requirements faced by the non-nuclear buildings analyzed in this chapter.

Table I-2 – Summary Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Seismic Building Safety Program	X	X	X
C2	Facility Emergency Management Program	X	X	X
M1	Fire Life Safety Portfolio Assessment	X	X	X
M2	Electrical Inspections	X	X	X
M3	Wind-Borne Debris Protection			X
M4	Work(er) Relocation		X	
M5	Building Replacement		X	
Mean (MARS)	*Cost Forecast ($ Million)*	$11.5	$46.8	$11.6
	Baseline Risk	2.42	2.42	2.42
	Risk Reduction (MRR)	0.30	0.35	0.34
	Remaining Risk	2.12	2.07	2.08
	Risk Spend Efficiency (RSE)	0.026	0.007	0.029
Tail Average (MARS)	*Cost Forecast ($ Million)*	$11.5	$46.8	$11.6
	Baseline Risk	7.77	7.77	7.77
	Risk Reduction (MRR)	0.96	1.12	1.09
	Remaining Risk	6.82	6.65	6.68
	Risk Spend Efficiency (RSE)	0.083	0.024	0.094

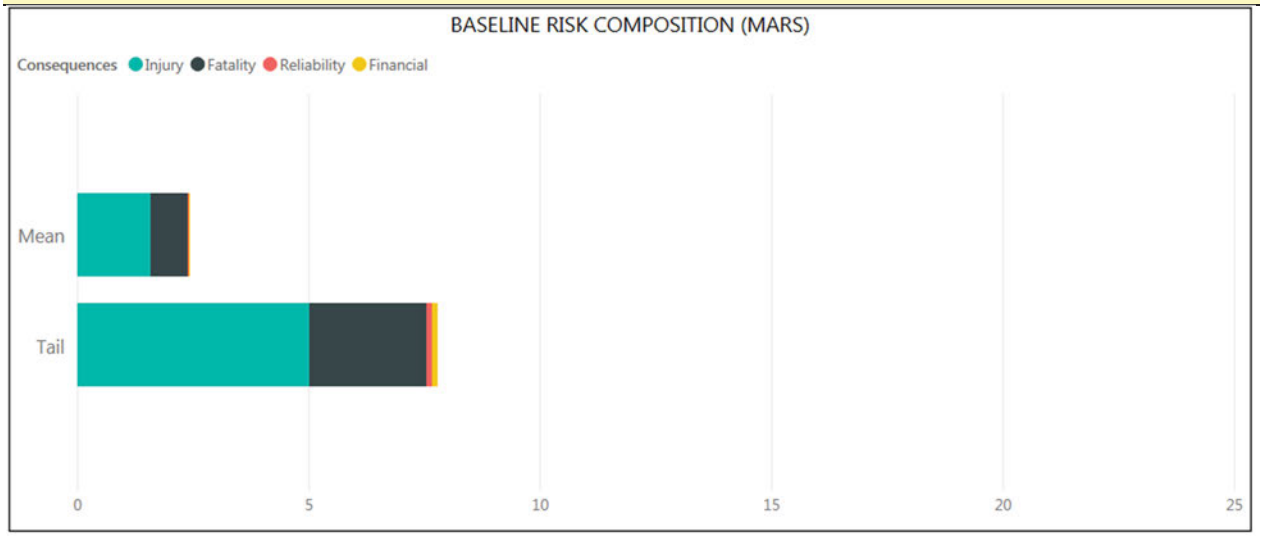
Figures represent 2018 - 2023 annual averages.

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS score is 100.

II. Risk Assessment

A. Background

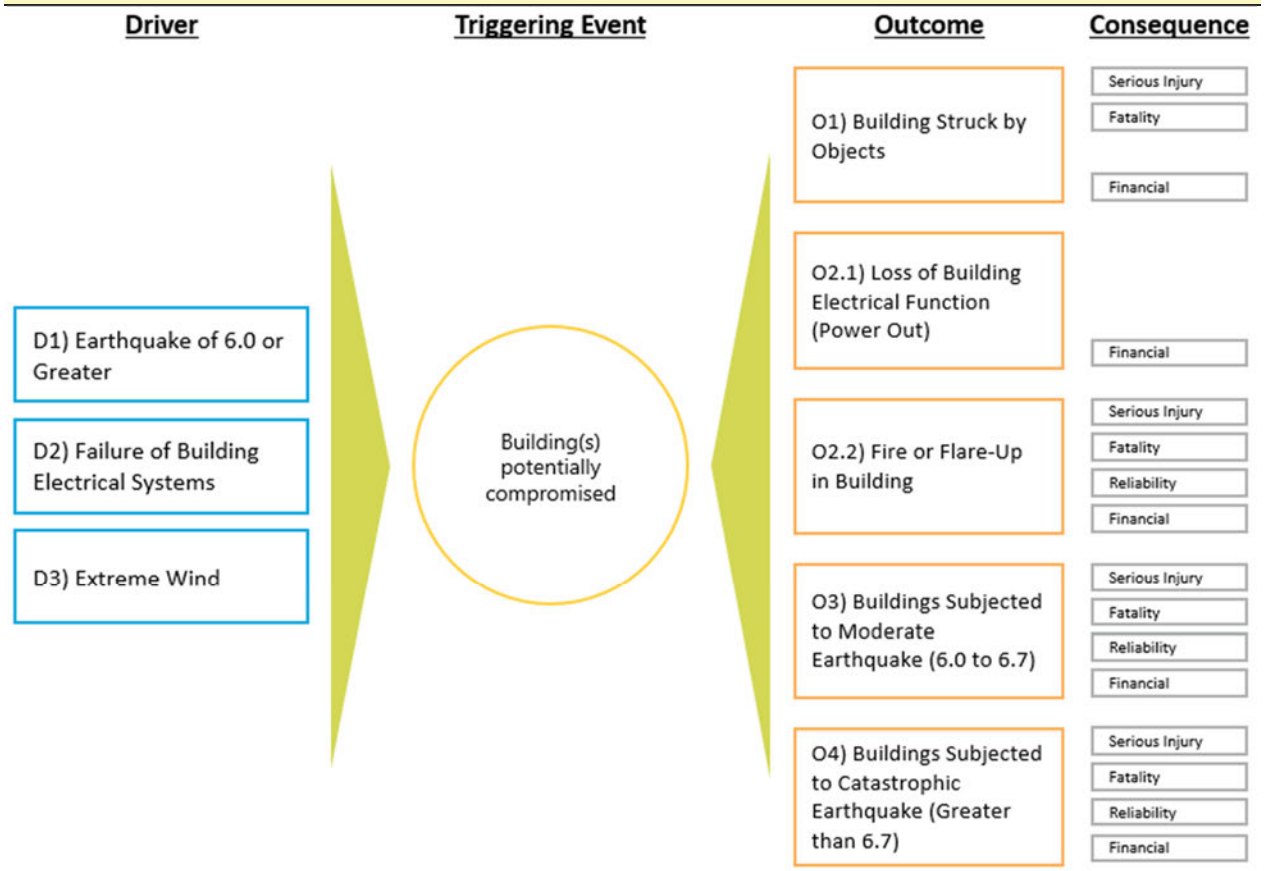
SCE employs a systematic and comprehensive approach to building safety. This includes policies, programs, procedures, and tools to help ensure that operations are performed in accordance with applicable laws, regulations, and best business practices. Our goal is to provide a safe and healthy work environment for our workers and visitors that come to our facilities. We describe these efforts in greater detail in Section III (Compliance & Controls) and Section IV (Mitigations).

Because seismic risk is a major element of building safety, SCE launched a Seismic Assessment and Mitigation Program in 2016 to promote company-wide seismic resilience (Appendix C – Seismic Events of SCE's RAMP report contains additional details on SCE's Seismic Assessment and Mitigation Program). This program coordinates seismic improvement projects for electric, generation, and telecommunications infrastructure, in addition to administrative and operational facilities. The 170 buildings within the scope of this chapter have been assessed under this program. The results of these assessments have informed both the priority for selecting buildings for seismic mitigations as well as the risk modeling presented in this chapter.

B. Risk Bowtie

To define and evaluate this risk, SCE has constructed a risk bowtie, as shown in Figure II-1. Each component of the bowtie represents a critical data point in evaluating this risk. SCE explains these components in detail in the sections that follow.

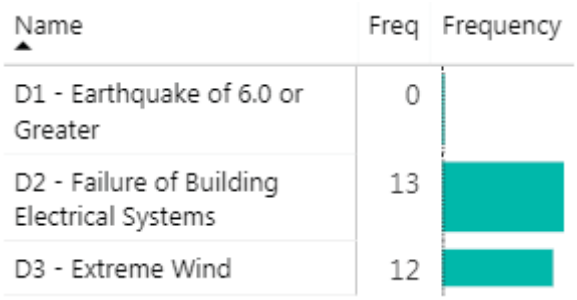
Figure II-1 – Building Safety Risk Bowtie



C. Drivers

SCE evaluated a large number of potential risk drivers related to building safety. After excluding several potential drivers (see Appendix A of this chapter for more detail), SCE developed this chapter around three drivers, shown in Figure II-2. Each driver is discussed in greater detail below.

Figure II-2 – 2018 Projected Driver Frequency*



Name	Freq
D1 - Earthquake of 6.0 or Greater	0
D2 - Failure of Building Electrical Systems	13
D3 - Extreme Wind	12

**D1 frequency is 0.3; the chart shows a value of 0 due to rounding.*

1. D1 – Earthquake of 6.0 or Greater

Table II-1 shows how the United States Geological Survey (USGS) has characterized earthquake outcomes for different levels of magnitude:

Table II-1 – USGS Earthquake Intensity Levels

Magnitude	Typical Maximum Modified Mercalli Intensity
1.0 - 3.0	I
3.0 - 3.9	II - III
4.0 - 4.9	IV - V
5.0 - 5.9	VI - VII
6.0 - 6.9	VII - IX
7.0 and higher	VIII or higher

Each intensity level (I, II, III, etc.) is characterized in terms of its "effects on people, human structures, and the natural environment." Intensity levels VII and above are characterized according to the USGS per the descriptions in Table II-2.

Table II-2 – Earthquake Intensity Level Outcome Characterizations

Level	Characterization
VII	Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable damage in poorly built or badly designed structures; some chimneys broken.
VIII	Damage slight in specially designed structures; considerable damage in ordinary substantial buildings with partial collapse. Damage great in poorly built structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned.
IX	Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb. Damage great in substantial buildings, with partial collapse. Buildings shifted off foundations.
X	Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations. Rails bent.
XI	Few, if any (masonry) structures remain standing. Bridges destroyed. Rails bent greatly.
XII	Damage total. Lines of sight and level are distorted. Objects thrown into the air.

Based on the USGS characterizations described above, SCE selected 6.0 (corresponding to intensity level VII and above) as a lower bound for the range of earthquakes that would potentially have safety impacts.

SCE analyzed driver frequency by comparing the location of the buildings in scope for this chapter against known earthquake faults and the potential for those faults to be active and to reach a magnitude of 6.0 or greater (as defined by the Uniform California Earthquake Rupture Forecast Version 3 Time-Dependent Model, or UCERF3-TD).[7] These simulations predicted that one or more occupied SCE buildings will experience strong shaking as the result of an earthquake of magnitude 6.0 or greater at a rate of 0.344 events per year (cumulatively for the entire portfolio of 170 buildings).

[7] Field, E. H., R. J. Arrowsmith, G. P. Biasi, P. Bird, T. E. Dawson, K. R. Felzer, D. D. Jackson, K. M. Johnson, T. H. Jordan, C. Madden, A. J. Michael, K. R. Milner, M. T. Page, T. Parsons, P. M. Powers, B. E. Shaw, W. R. Thatcher, R. J. Weldon, and Y. Zeng (2015). Long-Term, Time-Dependent Probabilities for the Third Uniform California Earthquake Rupture Forecast (UCERF3), Bull. Seism. Soc. Am. 105, 511–543.

2. D2 – Failure of Building Electrical Systems

Failure of critical electrical components can potentially cause loss of building operational systems, loss of power to the building, flare-ups, and fires.

The basic components of an electrical system are the main switchgear, circuit breakers, panel boards, and transformers. The voltage in these systems ranges from 120 volts to 480 volts.[8] Although rare, an electrical component or system can fail due to factors including age, operating conditions, circuit load, and maintenance. The focus of this driver is on major failures that have the potential to cause a loss of power within the building, a flare-up, or a fire.

SCE regularly inspects and replaces equipment before failure occurs, and has not historically tracked and maintained records regarding the specific cause of equipment failures. For example, SCE maintains records of the work orders and associated repair work. However, these records do not typically include the cause of the equipment failure. As such, SCE does not have a dataset of historical failures to inform a forecast of future failure rates. To estimate the potential frequency of failure, SCE used a building estimation model[9] to estimate the total number of electrical components per building category. SCE estimated a failure rate of 0.5%[10] after considering the compliance activities described in Section III. SCE then calculated event frequency as a function of the probability of failure multiplied by the number of electrical components. For example, if a building has four circuit breakers, the frequency of failure is 0.5% * 4 = 0.2 per year. Performing this analysis for the entire population of buildings in scope resulted in a driver frequency of 13.4.

3. D3 – Extreme Wind

Chapter 12 (Climate Change) discusses SCE's ongoing efforts to examine the near-, medium- and long-term vulnerabilities and impacts of climate change and extreme weather events.

As a complement to that analysis, SCE included extreme wind as a driver in this chapter. SCE narrowed the focus of extreme wind as a risk driver to focus on the safety risk that arises for building occupants when wind speeds occur that can potentially propel external objects through building walls or windows.

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[8] For example, building components such as HVAC equipment operate at 480 or 208 volts, lighting at 277 or 120 volts, and convenience outlets at 120 volts.

[9] This estimation model is used to model buildings and other assets, and it also contains component data derived from manufacturers, service providers, and site management.

[10] Failure rate estimation supported by SME with over 30 years of work experience in Facility Management. Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment) and to WP Ch. 4, pp. 4.13 (SME Qualifications).*

Hurricanes are measured on the Saffir-Simpson Hurricane Wind Scales,[11] which run from Category 1 up to Category 5. For purposes of this analysis, SCE defined extreme wind as anything equivalent to or greater than a Category 1 hurricane (where winds range from 74 to 95 mph). Winds at these speeds have the potential to move objects through the air. These objects can strike and potentially penetrate a building. Note that winds at this speed are not sufficient to tear off a roof that was constructed to the standards utilized by SCE; the resulting damage would likely be limited to operational inconvenience.

SCE performed a historical analysis of the frequency of extreme wind events at the 170 buildings in question. This analysis determined that, on average, there were 12.2 instances per year in which an individual building was subjected to extreme winds. This analysis was based on periods ranging from 19 to 31 years in duration (the timeframe of available data varies due to different times when measuring equipment was installed).

D. Triggering Event

The triggering event is defined as building(s) being potentially compromised, meaning the building is unable to fully ensure the safety of occupants. Figure II-3 shows the composition of the triggering event by individual drivers. As each driver is not expected to materially change in the short term, the frequency does not change over the RAMP time period.

Figure II-3 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	**Total**
Building Safety							
Baseline	**25.95**	**25.95**	**25.95**	**25.95**	**25.95**	**25.95**	**155.72**
Driver							
D1 - Earthquake of 6.0 or Greater	0.34	0.34	0.34	0.34	0.34	0.34	**2.06**
D2 - Failure of Building Electrical Systems	13.40	13.40	13.40	13.40	13.40	13.40	**80.40**
D3 - Extreme Wind	12.21	12.21	12.21	12.21	12.21	12.21	**73.26**
Total	**25.95**	**25.95**	**25.95**	**25.95**	**25.95**	**25.95**	**155.72**

[11] Category 1: 74-95mph; Category 2: 96-110mph; Category 3: 111-129mph; Category 4: 130-156mph; Category 5: 157mph or greater.

E. Outcomes & Consequences

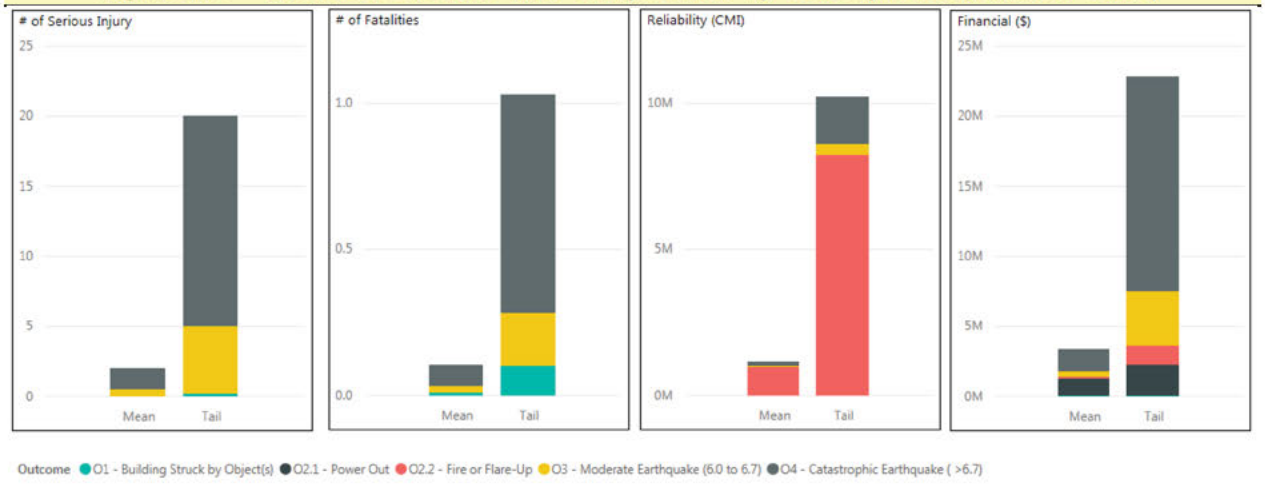
SCE has identified five outcomes, which are described in greater detail below. Figure II-4 indicates the relative likelihood of each outcome should the triggering event occur.

Figure II-4 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Building Struck by Object(s)	47.0 %	
O2.1 - Power Out	50.9 %	
O2.2 - Fire or Flare-Up	0.8 %	
O3 - Moderate Earthquake (6.0 to 6.7)	0.8 %	
O4 - Catastrophic Earthquake (>6.7)	0.5 %	

Figure II-5 illustrates the composition of the modelled baseline risk in terms of each consequence dimension. The sections that follow describes the inputs used to derive these results.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (Natural Units)



1. O1 – Building Struck by Objects

Outcome 1 is related to potential damage caused by wind-borne objects that strike and potentially penetrate the building envelope, causing a safety risk to building occupants within the building. Examples include wind-propelled material from trees, poles, and towers. In

addition, debris coming from neighboring buildings or equipment that are not securely fastened to the building or anchored to the ground could become airborne and penetrate a window.

Potential consequences from O1 are summarized on an annualized basis in Table II-3. Serious injuries and fatalities are associated with occupants located near the window where the building is struck. Financial costs are associated with repairing the damage. For O1, the estimate of annual impacts is .002 serious injuries, .001 fatalities, and $37K of financial harm on a mean basis, and .0016 serious injuries, .008 fatalities, and $66K of financial harm on a tail-average basis.

Table II-3 – Outcome 1 (Building Struck by Objects): Consequence Details[12]

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform statistical distribution*	Facilities experts estimated range of 0-3 serious injuries per occurrence based on evaluation of employee proximity to potential window impact locations given typical arrangement of SCE workstations.	50% of injury range, based on historical ratio of fatalities per injury for wind events in California from 2013 through 2017. Data source is National Oceanic and Atmospheric Administration storm events database.	N/A	SCE facility managers estimated property damages would range from $0-150K, with an average expected cost of $20K based on repairs costs under typical scenarios.
Model Outputs	NU - Mean	0.02	0.01	N/A	$37K
	NU - Tail Avg	0.20	0.10	N/A	$66K

2. O2.1 – Loss of Building Electrical Function (Power Out)

Outcome 2.1 evaluates consequences when one or more building systems dependent on electricity (e.g., lights, air conditioning, elevators, etc.) lose functionality, requiring employees to vacate the building and rendering it inoperable until functionality is restored. Restoration times would typically be less than 24 hours.

Potential consequences from O2.1 are summarized on an annualized basis in Table II-4. Financial costs are associated with repairing the damage. For O2.1, the estimate of annual impacts is $1.2M of financial harm on a mean basis, and $2.1M of financial harm on a tail-average basis.

[12] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

Table II-4 – Outcome 2.1 (Building Power Out): Consequence Details[13]

Outcome 2.1		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform statistical distribution*	N/A	N/A	N/A	Based on SCE historical facility capital repair costs over 2016-17 (limited to building types in scope).
Model Outputs	NU - Mean	N/A	N/A	N/A	$1.2M
	NU - Tail Avg	N/A	N/A	N/A	$2.2M

3. O2.2 – Fire or Flare-up in Building

Outcome 2.2 evaluates potential consequences when the failure of building electrical systems results in an arc flash. An arc flash is the sudden release of electrical energy that jumps through the air, and is caused when a high-voltage gap exists between conductors in building electrical systems or equipment. During an arc flash, energy is released that can reach up to 35,000 degrees Fahrenheit. An arc flash and the associated flare-up has the potential to cause a fire.

Potential consequences from O2.2 are summarized on an annualized basis in Table II-5. Serious injuries and fatalities are associated with occupants located in the building when the fire occurs. Reliability impacts are associated with the potential for the fire to damage equipment within an occupied building that is critical to providing electrical service to customers. Financial costs are associated with repairing the damage.

For O2.2, the estimate of annual impacts is .0027 serious injuries, .0002 fatalities, 952K customer minutes of interruption (CMI), and $141K of financial harm on a mean basis; and .0270 serious injuries, .0022 fatalities, 8.2M CMI, and $1.4M of financial harm on a tail-average basis.

[13] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

Table II-5 – Outcome 2.2 (Fire or Flare-Up): Consequence Details[14]

Outcome 2.2		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform statistical distribution*	Average injury rate of .014 based on two industry data sources (FEMA & National Fire Protection Agency).	Average fatality rate of .0014 based on two industry data sources (FEMA & NFPA).	Based on the same analysis as Outcome 4, but scaled down to represent impact to a single building (as opposed to multiple buildings in the earthquake scenario in Outcome 4).	Estimates of repair costs range from building equipment replacement costs to full-scale building destruction due to fire, based on historical repair costs and facility manager experience.
Model Outputs	NU - Mean	0.003	0.0002	952K CMI	$141K
	NU - Tail Avg	0.027	0.0022	8.2M CMI	$1.4M

4. O3 – Buildings Subjected to Moderate Earthquake (6.0 to 6.7)

Outcomes 3 and 4 capture the range of possible impacts under moderate and catastrophic earthquake conditions.

As discussed in Section II, SCE used the minimum of 6.0 as a lower bound for an earthquake magnitude that has the potential for safety impacts. SCE then separated the range of potential earthquakes outcomes above 6.0 into two categories (6.0 to 6.7 and greater than 6.7) to more clearly identify the difference in a moderate earthquake versus a catastrophic earthquake. SCE used USGS analyses[15] to define the cutoff of 6.7 to serve as the threshold for a catastrophic earthquake.

Shaking intensity is related to magnitude, distance from epicenter, and other geological variables such soil composition. The extent of damage, serious injuries, and fatalities will vary based on factors such as the age and design of a building, the height of a building, and its distance from the epicenter of the earthquake.

[14] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

[15] UCERF3: A New Earthquake Forecast for California's Complex Fault System; the UCERF3 analysis uses 6.7 as threshold as it matches the magnitude of the 1994 Northridge earthquake, *available at* http://www.wgcep.org/ucerf3

In addition to safety risks that an earthquake may impose on occupants of buildings, and the financial cost to address building damage, an earthquake has the potential to cause sufficient damage to a manned substation control center building to cause reliability impacts.[16]

Potential consequences from O3 are summarized on an annualized basis in Table II-6. Serious injuries and fatalities are associated with occupants located in the building when the earthquake occurs. Reliability impacts are associated with the potential for the earthquake to damage equipment within an occupied building that is critical to providing electrical service to customers. Financial costs are associated with repairing the damage.

For O3, the estimate of annual impacts is .486 serious injuries, .018 fatalities, 42K customer minutes of interruption (CMI), and $419K of financial harm on a mean basis; and 4.827 serious injuries, .181 fatalities, 363K CMI, and $3.9M of financial harm on a tail-average basis.

Table II-6 – Outcome 3 (Moderate Earthquake): Consequence Details[17]

Outcome 3		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform statistical distribution*	Customized expert analysis performed by third party based on granular, building-level data (e.g. location, occupied population, condition, replacement cost, etc.).	Derived as part of analysis described in Serious Injuries.	Derived as part of analysis described in Serious Injuries.	Derived as part of analysis described in Serious Injuries.
Model Outputs	NU - Mean	0.49	0.02	42K CMI	$419K
	NU - Tail Avg	4.83	0.18	363K CMI	$3.9M

5. O4 – Buildings Subjected to Catastrophic Earthquake (greater than 6.7)

We analyzed outcome 4 using the same approach as Outcome 3, but at a higher level of earthquake magnitude. In a large earthquake of magnitude 6.7 or greater, there is

[16] Due to this chapter's scope of occupied buildings, the analysis presented here does not include reliability impacts that an earthquake could cause by damaging unoccupied buildings or facilities, especially substation facilities, which are more likely than occupied buildings to have direct reliability impacts to electrical service.

[17] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

greater risk of building collapse and red-tagging (meaning a building does not collapse but can no longer be safely occupied).

Potential consequences from O4 are summarized on an annualized basis in Table II-7. Serious injuries and fatalities are associated with occupants located in the building when the earthquake occurs. Reliability impacts are associated with the potential for the earthquake to damage equipment within an occupied building that is critical to providing electrical service to customers. Financial costs are associated with repairing the damage.

For O3, the estimate of annual impacts is 1.502 serious injuries, .075 fatalities, 167K customer minutes of interruption (CMI), and $1.6M of financial harm on a mean basis; and 15.001 serious injuries, .750 fatalities, 1.6M CMI, and $15.3M of financial harm on a tail-average basis.

Table II-7 – Outcome 4 (Catastrophic Earthquake): Consequence Details[18]

Outcome 4		**Consequences**			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform statistical distribution*	Customized expert analysis performed by third party based on granular, building-level data (e.g. location, occupied population, condition, replacement cost, etc.).	Derived as part of analysis described in Serious Injuries.	Derived as part of analysis described in Serious Injuries.	Derived as part of analysis described in Serious Injuries.
Model Outputs	NU - Mean	1.50	0.08	167K CMI	$1.6M
	NU - Tail Avg	15.00	0.75	1.6M CMI	$15.4M

[18] Please refer to WP Ch. 4, pp. 4.1 – 4.4 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

III. Compliance & Controls

Table III-1 maps controls to drivers, outcomes, and consequences, in addition to showing 2017 recorded costs for both compliance activities and controls.[19]

Table III-1 – Inventory of Compliance & Controls

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	Fire Life Safety Compliance	Not Modeled	Not Modeled	Not Modeled	$ 0.616	$ 0.254
CM2	Electrical Compliance	Not Modeled	Not Modeled	Not Modeled	$ 2.554	$ 0.249
C1	Seismic Building Safety Program	-	O3, O4	All	$ 8.936	$ 0.008
C2	Facility Emergency Management Program	-	O2.2, O3, O4	S-I, S-F	$ -	$ 0.417

Consequence abbreviation: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial – F

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities <u>are not</u> modeled in this report. Compliance activities are addressed in Section III.

C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls <u>are</u> modeled this report, and are addressed in Section III.

A. CM1 – Fire Life Safety Compliance

A Fire Life Safety (FLS) System is an integrated system of components, equipment and sub-systems installed in a building to prevent or reduce the likelihood of fire outcomes that may result in injury, fatality, or property damage. FLS systems and components are typically focused on fire detection, suppression, and/or notification of building occupants.

Buildings have combinations of FLS equipment depending on the building's design and use, and the requirements of the local authorities. The local fire authority has primary jurisdictional approval of the design, components, and configuration of a building's FLS system.

Table III-2 summarizes inspections and testing requirements related to FLS compliance.

[19] Please refer to WP Ch. 4, pp. 4.5 – 4.12 *(Control Mitigation Risk Reduction Effectiveness)* for further details on the data sources and methodology to estimate control effectiveness.

Table III-2 – FLS Compliance Inspections and Tests

Sub-System	Activity Type	Component Tested
Fire Alarm	Annual Visual Inspection	Batteries, sub-panels, initiating devices (heat/smoke detectors), pull stations, horns, strobes, bells.
	Bi-Annual Test	Battery voltage (for non-monitored panels).
Sprinkler System: Wet	Quarterly Visual Inspection	Alarm devices, hydraulic nameplates, gauges, control valves, alarm valves, pipes and fittings, sprinklers, spare sprinklers, fire department connections.
	Annual Visual Inspection	Bracings and hangers, alarm devices, control valve position/operation, main drain test, supervisory flow test.
	5-Year Test	Piping obstruction, concealed accessible spaces, pressure-reducing valves, gauges, fire department connections, sprinklers.
Sprinkler System: Dry Pipe	Annual Test	Priming water test, low air pressure test, quick opening device test, full flow trip test, low point drain test.
	Quarterly Visual Inspection	Valves.
	5-Year Test	Piping obstruction, alarm valve obstruction.
Sprinkler System: Pre-Action	Annual Test	Priming water test, low air pressure test, quick opening device test, full flow trip test, low point drain test.
	Quarterly Visual Inspection	Valve operation.
	5-Year Test	Piping obstruction inspection, alarm valve obstruction inspection.
Sprinkler System: Deluge	Annual Test	Full flow trip test.
Sprinkler System: Gas Suppression	Annual Test	Batteries, sub-panels, initiating devices (heat/smoke detectors), pull stations, horns, strobes, bells.
Foam System	Annual Test	Discharge device, detection system, piping, foam concentrate/solution proportioning, control valve.
	5-Year Test	Full flow trip test.
Fire Pump	Weekly Test	Pump test, PSI check, leak check, packing test.
	Annual Test	Full flow trip test.
	5-Year Test	Piping obstruction, concealed accessible spaces, pressure-reducing valves, gauges, fire department connections, sprinklers.

Following each of the inspections or tests noted above, inspection and testing records document SCE's adherence to the compliance requirement.

Fire extinguishers are also an important component of FLS systems, and SCE makes sure that certification and records for fire extinguishers are up to date (they are renewed on an

annual basis per the State Fire Marshall). SCE also performs a monthly physical inspection to validate that fire extinguisher tags reflect current compliance.

B. CM2 – Electrical Compliance

SCE's building electrical compliance activities are primarily dictated by the National Electric Code (NEC). The NEC, which is also known as NFPA 70, is a set of electrical design and installation standards published by the National Fire Protection Association (NFPA). Although the NFPA is not a government organization, many state and local governments (including California at a state level and cities within SCE's service territory) codify NFPA standards as the requirements under their jurisdiction. As noted by the NFPA, "[a]dopted in all 50 states, the NEC is the benchmark for safe electrical design, installation, and inspection to protect people and property from electrical hazards."

NFPA 70E, which was first published in 1979, is a separate but related set of NFPA standards intended to "use policies, procedures, and program controls to reduce the risk associated with the use of electricity." Though the Occupational Safety and Health Administration (OSHA) does not explicitly dictate the use of NFPA 70E, OSHA mandates that employers use industry standards and practices that will protect their workforce from harm. NFPA 70E was developed to help building owners and employers comply with the OSHA requirements.

SCE maintains compliance in all facility operations and construction activities requiring adherence to NFPA 70. For example, new construction projects are inspected by permitting agencies, and electrical projects are performed by licensed electricians. NFPA 70E requirements include activities such as reviewing arc flash information.

C. C1 – Seismic Building Safety Program[20]

Seismic mitigations to improve building safety can be characterized in two categories: structural and non-structural.

Structural mitigation or retrofits involve modifying an existing building to make it more resistant to seismic activity, ground motion, or soil failure. For example, a retrofit could include adding anchors and roof-to-wall straps to existing structures. Retrofits are tailored to specific performance objectives, such as preventing structural collapse and occupant harm or increasing the chance that the building can continue operations after an earthquake.

[20] This control is titled "Seismic Assessment and Mitigation Programs: Non-Electric Facility Mitigation" in SCE's 2018 General Rate Case testimony A.16-09-SCE-07, Vol. 1

Non-structural mitigations are improvements that help prevent large objects (such as storage racks and cabinets) from falling during seismic events. Equipment (e.g., large mechanical, electrical, or plumbing systems) and furnishings that are reinforced or held in place will pose less of a safety hazard both during and after an earthquake. These activities also support faster restoration of operations following an earthquake.

This mitigation focuses on work that exceeds buildings codes and standards. Because codes and standards are typically linked to the point in time when a building was constructed, they may not reflect advances in science and engineering that have informed seismic-related safety improvements. SCE initiated seismic work at a pace of approximately 10 buildings pear year starting in 2016. SCE proposes to continue this pace through the RAMP period.

1. Drivers Impacted

None.

2. Outcomes and Consequences Impacted

This control affects all consequences of O3 (Moderate Earthquake) and O4 (Catastrophic Earthquake). Structural and non-structural retrofits to buildings improve the safety of a building in the event of an earthquake, in addition to reducing the potential for repair costs and operational interruptions.

D. C2 – Facility Emergency Management Program

The Facility Emergency Management program oversees the maintenance of SCE's Emergency Action Plan, and trains employees on proper safety protocols during and after an event such as a fire or earthquake.

SCE has been performing this work in various forms for more than 20 years. Employees are trained to assist with safe egress, to check for injured employees, and to account for all building occupants once they are outside. The program coordinates an annual duck/cover/hold drill in coordination with the statewide Great Shakeout,[21] and manages stocks of emergency aid, water, and food supplies at different building sites.

The Facility Emergency Management program trains and assigns an Emergency Resource Coordinator at each campus as well as Life Safety Coordinators in each occupied building. As a result of regular training and drills, larger buildings are typically evacuated in less than five minutes, and smaller buildings in less than three minutes. The program includes floor sweeps

[21] The California Great ShakeOut is an annual statewide earthquake drill that allows participants to practice safety preparedness procedures as well as reassess preparedness efforts, *available at* https://www.shakeout.org/california/

and roster validations to help ensure that building occupants and visitors are fully accounted for.

1. Drivers Impacted

None.

2. Outcomes & Consequences Impacted

This control affects serious injuries and fatalities resulting from O2.2 (Fire or Flare-Up), O3 (Moderate Earthquake), and O4 (Catastrophic Earthquake). Proper evacuation and safety procedures help reduce the potential for injury during and after an earthquake or fire.

IV. Mitigations

Table IV-1 maps each mitigation to drivers, outcomes, and consequences, in addition to showing 2017 recorded costs.[22]

Table IV-1 – Inventory of Mitigations

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Proposed	Alt. #1	Alt. #2
M1	Fire Life Safety Portfolio Assessment	-	O2.2	S-I, S-F	x	x	x
M2	Electrical Inspections	D2	-	-	x	x	x
M3	Wind-Borne Debris Protection	-	O1	All			x
M4	Work(er) Relocation	-	O3, O4	All		x	
M5	Building Replacement	-	O3, O4	All		x	

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled this report, and are addressed in Section IV.

A. M1 – Fire Life Safety Portfolio Assessment

SCE's FLS approach has been based on compliance requirements, which are typically designed around minimum safety standards and are not necessarily forward-looking.

SCE proposes to systematically identify, compare, and evaluate potential FLS system changes that would exceed compliance requirements. For example, SCE would evaluate whether sprinkler systems are appropriate in some cases in which they are not required.

This mitigation entails developing and implementing a building-level assessment of FLS systems in place across all 170 buildings in scope, and comparing the costs and benefits of changes that would exceed compliance standards.

The assessment would include the identification and execution of work within the RAMP period, which SCE would execute at a pace of approximately two to four building sites per year. (Please note that only a subset of the 170 buildings are expected to be selected for implementing FLS changes.)

1. Drivers Impacted

None.

[22] Please refer to WP Ch. 4, pp. 4.5 – 4.12 *(Control Mitigation Risk Reduction Effectiveness)* for further details on the data sources and methodology to estimate mitigation effectiveness.

2. Outcomes & Consequences Impacted

This mitigation reduces the potential for serious injuries and fatalities associated with O2.2 (Fire or Flare-Up), as FLS systems are designed to suppress the spread of fire and/or provide detection and notification of fires. While this mitigation may also reduce the potential for repair costs due to fire damage, in some cases it is also possible that water damage due to sprinklers can equal the repair costs that would have been incurred if the fire had not been suppressed. Hence, SCE has not assumed a reduction in the financial consequence.

B. M2 – Electrical Inspections

This mitigation entails developing and implementing a portfolio-wide arc flash and thermal infrared survey of building electrical system components, which is identified as an emerging need by industry experts.[23] An arc flash study assesses the maximum incident energy levels of an electrical circuit. An infrared thermography analysis measures excess heat to identify problems before an electrical component fails.[24]

Inspections would be performed on the entire 170 building portfolio on a rolling five-year basis. Inspections would include main breakers, switchgear, subpanels, circuit breakers, and transformers that are downstream of the electrical meter. Scheduling and prioritizing inspections would be informed by internal metrics that have been derived from industry standards such as Facility Condition Index (FCI)[25] and Asset Priority Index (API).[26] Approximately 20% of the buildings in the portfolio would be surveyed on an annual basis.

1. Drivers Impacted

This mitigation reduces D2 (Failure of Building Electrical Systems) by identifying electrical deficiencies that can be corrected before failure occurs.

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[23] Electrical Systems: Don't Get Burned, Facilities Management Journal, March/April 2017, *available at* http://fmj.ifma.org/publication/?i=392368&article_id=2737130&view=articleBrowser&ver=html5#{%22issue_id%22:392368,%22view%22:%22articleBrowser%22,%22article_id%22:%222737130%22}

[24] Because increased heat is a sign of existing or potential failure, infrared serves as an effective diagnostic tool to locate connections in early stages of degeneration.

[25] FCI is a ratio comparing the total deferred maintenance for a building to its estimated replacement value. The higher the ratio, the larger the capital needed to keep the existing building in a functioning state relative to replacement.

[26] API is a tool used in facility management to support portfolio-level decision making that makes the best use of available resources.

2. Outcomes & Consequences Impacted

None, as this is a preventative activity to reduce the potential for failure before it occurs. In some cases, an inspection might identify an electrical component that will be replaced with a newer component that is designed to reduce the extent of fire should failure occur. However, due to the case-by-case nature of such potential improvements, it is not possible at this time to quantify the impact in this analysis with a satisfactory level of accuracy or certainty.

C. M3 – Wind-Borne Debris Protection

This mitigation involves installing a transparent film on windows to improve the window's ability to resist penetration and shattering. The mitigation would be targeted at sites located in extreme wind zones. Approximately 15 of the 170 buildings are located in extreme wind zones.

1. Drivers Impacted

None.

2. Outcomes & Consequences Impacted

All consequences associated with O1 (Building Struck by Objects), as this mitigation increases the strength of the window and its ability to withstand impact from a wind-blown object.

D. M4 – Permanent Work(er) Relocation

In instances where the cost associated with retrofitting a building and/or upgrading components is financially unreasonable, it may be appropriate to permanently relocate the work and the workers to alternate locations. This mitigation can potentially reduce the number of SCE's occupied buildings and the overall building portfolio safety risk exposure.

The San Bernardino Regional Office provides a historical example of how SCE has utilized this type of mitigation. This Regional Office was vacated in 2017 out of an abundance of caution due to its proximity to active earthquake faults. The building was designed to house 250 people, and over 215 office workers were dispersed to alternate locations. Although the facility was constructed according to the building codes and standards in place when it was built in 1958, the seismic risk was considered unacceptable due to advances in both the understanding of seismic risk at this geographic location as well as present-day building engineering and design standards.

This mitigation requires available capacity in other buildings to absorb the work and/or workers that are relocated. For example, destination locations may have limited parking space,

or only have temporary occupancy while a relocation into the facility is in progress.[27] In considering available capacity, we must also take into account that unexpected needs may arise (such an unforeseeable condition or event rendering a building inoperable and forcing us to send workers to an alternate location).

Finally, this mitigation is less feasible for buildings where certain types of specialized technical work occurs. Specialized work includes garages, service centers, maintenance and test buildings and substations. This work cannot be easily relocated for reasons that include the need to maintain geographic proximity to work sites as well as policies related to represented employees.

Due to the limitations described above, this mitigation only evaluates a small number of buildings. SCE identified three buildings[28] as potential candidates for this mitigation.

1. Drivers Impacted

Relocating workers from the specific facilities that would be involved in this mitigation does not change the exposure to earthquake or extreme winds. While it is possible that the potential for electrical failure would be reduced when comparing the original location of the workers to the new location, this benefit is difficult to quantify and is unlikely to materially impact the analysis. As such, SCE did not model this potential benefit.

2. Outcomes & Consequences Impacted

All consequences for O3 (Moderate Earthquake) and O4 (Catastrophic Earthquake) are impacted.

E. M5 – Building Replacement

As described above, SCE's seismic program has identified and prioritized the buildings that would benefit from seismic improvements. In some circumstances, replacing a building may be more appropriate when a) the cost of needed upgrades approaches the replacement cost of the building, and b) workers cannot be permanently relocated to other locations. Additionally, buildings that are not currently in scope for C1 may be candidates for replacement due to non-structural reasons such as physical condition or fitness for purpose.[29]

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[27] Under industry best practices, it may be prudent for SCE to maintain a certain amount of unoccupied capacity to allow for future expansion and relocations within the building.
[28] Long Beach Regional Office, Redlands Service Center Kansas Building, and Alhambra Control Center Building D.
[29] The term "fitness for purpose" refers to whether a building is suitable for current and anticipated future needs.

Because buildings with the greatest needs for seismic safety improvements have been included in C1, the incremental safety benefits from this mitigation are relatively modest. Based on operational feasibility, M5 would replace two buildings per year. Prior to deploying this mitigation, SCE would undertake a robust business case analysis to evaluate the full costs and benefits of the effort, including but not limited to safety considerations. For example, SCE has considered replacing buildings in its 2018 GRC.[30]

1. Drivers Impacted

None. Due to the specific facilities that could be included in this mitigation, moving a building's occupants into a new building that would replace the prior site does not change the exposure to drivers. Moreover, because such a move would represent a change in only 1 out of the population of 170 buildings, it would not materially impact the overall analysis and RSE results presented in this chapter.

2. Outcomes & Consequences Impacted

All consequences for O3 (Moderate Earthquake) and O4 (Catastrophic Earthquake), due to replacing an older facility with a current building that meets or exceeds present-day seismic codes and standards.

[30] See SCE 2018 GRC: Exhibit SCE-07, Vol. 3, Workpaper Book A, p. 37.

V. Proposed Plan

Table V-1 – Proposed Plan

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Building Safety Program	2018	2023	$ 42.2	$ 5.9	0.73	0.015	2.56	0.053
C2	Facility Emergency Management Program	2018	2023	$ -	$ 0.8	0.19	0.226	0.65	0.794
M1	Fire Life Safety Portfolio Assessment	2018	2023	$ 5.0	$ 0.9	0.001	0.0001	0.003	0.0005
M2	Electrical Inspections	2019	2023	$ 5.0	$ 9.5	0.87	0.060	2.57	0.177
			Total - Proposed Plan	**$ 52.2**	**$ 17.1**	**1.79**	**0.026**	**5.78**	**0.083**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

A. Overview

SCE's proposed plan is based on continuing its existing seismic program and implementing two new mitigations related to FLS systems and electrical safety.

A significant portion of the risk reduction in this plan comes from the C1 (Seismic Building Safety Program), due to its extensive scope and its role in mitigating a large source of the risk within this chapter. SCE recommends continuing the seismic program as a foundational activity to mitigate one of the most significant risks facing occupants of our buildings. SCE also recommends continuing the facility emergency management program, which is consistent with established industry practice.

The additional activities in the proposed portfolio provide targeted and efficient mitigation of building fire risk (i.e., the electrical and fire safety activities in M1 and M2). Accordingly, these mitigations are included in both Alternative Plans as well.

B. Execution Feasibility

The primary considerations when evaluating the execution feasibility of this plan include internal work coordination and external permitting and scope issues.

With regard to internal work coordination, both costs and operational impacts are minimized when construction activities are consolidated and performed at the same time at the same site. For example, if a building needs structural retrofits, general renovations, and changes to accommodate IT infrastructure, it is more economical to perform all of the work at

the same time. In addition to the economies offered by bundling the work, disruption to workers is reduced as the need for temporary facilities and the relocation is minimized.

With regard to permitting and scope issues, SCE cannot always anticipate the response time and changing requirements of local authorities. For example, bandwidth constraints at a municipality may delay key permits, or SCE may be required to expand the scope of work to meet new building codes.[31]

C. Affordability

This Plan's Risk Spend Efficiency (RSE) is the second highest RSE of the three plans considered. Alternative Plan #2 derives a marginally higher RSE than the Proposed Plan (.029 vs. .026) due to the inclusion of M3 (Wind-Borne Debris Protection). SCE considered including M3 in the Proposed Plan, but we ultimately determined that more research is needed to identify the appropriate scope of deployment for this mitigation, and further investigation into window film products is needed.

This plan includes controls and mitigations for which we have a reasonable level of certainty of scope and cost at this point in time.

D. Other Considerations

SCE is not aware of constraints beyond what we mentioned above.

[31] Generally speaking, the requirement to upgrade a building from compliance with the code in force at the time of construction to present-day code could be triggered based on the extent of changes that are undertaken.

VI. Alternative Plan #1

Table VI-1 – Alternative Plan #1

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Building Safety Program	2018	2023	$ 42.2	$ 5.9	0.74	0.016	2.60	0.054
C2	Facility Emergency Management Program	2018	2023	$ -	$ 0.8	0.19	0.232	0.67	0.811
M1	Fire Life Safety Portfolio Assessment	2018	2023	$ 5.0	$ 0.9	0.001	0.0001	0.003	0.0005
M2	Electrical Inspections	2019	2023	$ 5.0	$ 9.5	0.94	0.065	2.73	0.188
M4	Work(er) Relocation	2019	2023	$ 0.5	$ 0.1	0.08	0.127	0.26	0.443
M5	Building Replacement	2019	2023	$ 211.0	$ -	0.14	0.001	0.49	0.002
			Total - Alternative Plan #1	**$ 263.7**	**$ 17.2**	**2.09**	**0.007**	**6.75**	**0.024**

MARS = Multi-Attribute Risk Score.
MRR = Mitigated Risk Reduction.
RSE = Risk Spend Efficiency.

A. Overview

Alternative Plan #1 includes all controls and mitigations as in the Proposed Plan, as well as M4 (Worker Relocation) and M5 (Building Replacement). This plan would require minor adjustments[32] to the volume and sequencing of work performed across the other controls and mitigations due to changes in the building portfolio as a result of implementing M4 (Worker Relocation) and M5 (Building Replacement).

When considered from the safety-oriented perspective of RAMP, the high cost of executing this portfolio (an additional $211.5M in capital) makes it less compelling on a RSE basis. However, as noted in the description of M5 (Building Replacement) in Section IV, SCE has determined that replacing buildings is appropriate in some cases due to the combination of safety and non-safety benefits.

B. Execution Feasibility

This plan shares the same issues as the Proposed Plan with regard to internal work coordination and external permitting and scope issues.

It also includes additional operational considerations (previously discussed in Section IV) such as finding alternative work locations for workers who are displaced due to their building being closed or replaced. M5 (Building Replacement) also presents operational considerations such as the availability of external resources to perform building replacement work.

[32] While this would impact work management practices, it would not have a material impact on the RAMP analysis.

C. Affordability

This plan costs approximately five times more in capital than the Proposed Plan ($263.7M vs. $52.2M), yet only delivers approximately 17% percent greater risk reduction (2.09 vs. 1.79). The difference is due to the high cost of M5 (Building Replacement), which does not have a commensurate risk reduction. As a result, SCE believes the Proposed Plan is a more efficient use of funds based on what we know now.

SCE will continue to evaluate this Alternative Plan as our facilities age and deteriorate. As previously discussed, deteriorating buildings conditions (as measured by the Facility Condition Index) and the criticality of certain facilities (as measured by the Asset Priority Index), may necessitate resorting to M5 (Building Replacement). SCE has, and will continue to, evaluate building replacements as a viable and necessary mitigation for this risk.

D. Other Considerations

None beyond what is mentioned above.

VII. Alternative Plan #2

Table VII-1 – Alternative Plan #2

Alternative #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Building Safety Program	2018	2023	$ 42.2	$ 5.9	0.74	0.015	2.59	0.054
C2	Facility Emergency Management Program	2018	2023	$ -	$ 0.8	0.19	0.228	0.66	0.803
M1	Fire Life Safety Portfolio Assessment	2018	2023	$ 5.0	$ 0.9	0.001	0.0001	0.003	0.0005
M2	Electrical Inspections	2019	2023	$ 5.0	$ 9.5	0.92	0.064	2.71	0.187
M3	Wind-Borne Debris Protection	2019	2023	$ 0.3	$ -	0.18	0.717	0.59	2.369
			Total - Alternative Plan #2	**$ 52.4**	**$ 17.1**	**2.03**	**0.029**	**6.55**	**0.094**

MARS = Multi-Attribute Risk Score.
MRR = Mitigated Risk Reduction.
RSE = Risk Spend Efficiency.

A. Overview

Alternative Plan #2 includes all controls and mitigations as included in the Proposed Plan, with the addition of M3 (Wind-Borne Debris Protection) to mitigate the risk from wind-borne objects.

While this portfolio is compelling from an RSE perspective, SCE needs to fully evaluate individual building candidates to receive treatment from M3, and to more fully evaluate potential window film products.

B. Execution Feasibility

This plan shares the same considerations as the proposed plan with regard to internal work coordination and external permitting and scope issues.

For M3, the scope of work would be determined by building sites with high exposure to extreme wind speeds (approximately 15 sites). Although the work is not technically complex, timing of the work would be determined by evaluating whether to bundle the work with other projects or initiating it as a standalone effort.

C. Affordability

The RSE of this portfolio is .029, which nearly identical to the RSE of the proposed plan. While the incremental cost of M3 is marginal relative to the remainder of the plan, SCE does not feel it prudent to pursue this mitigation at this time due to the need for further evaluation.

D. Other Considerations

None beyond what is mentioned above.

VIII. Lessons Learned, Data Collection & Performance Metrics

A. Lessons Learned

Data availability was a challenge. Improved data pertaining to specific building components and life cycles would have enhanced the analysis by allowing for asset-specific information. Furthermore, the attempt to analyze existing and future risk levels would have benefited from a greater record of historical data pertaining to specific causes of recorded failures of electrical components. With respect to costs, in some cases current accounting codes were too broad and did not allow for readily available tracking of work at a more detailed level.

SCE is currently migrating to a new facilities management technology[33] that will streamline end-to-end facilities management from service request intake to work orders management to invoice handling and payment. This capability will improve access to data and reporting, thereby addressing some of the data challenges.

B. Data Collection & Availability

SCE has initiated the following efforts to improve data collection for this risk:

- Enhancements to Archibus[34] to improve data collection and integrity related to building occupancy.
- Accounting changes to track costs at a more granular level.

SCE is considering additional efforts to improve data collection:

- Evaluating enhancements to the eComet[35] database system to expand the types of building components being tracked and to include dashboard reporting capabilities.
- Evaluating an increase in participation in the International Facility Management Association (IFMA) to systematically identify and implement industry-standard data collection processes and analytics.

[33] Service Insight 7/JDE.
[34] The Archibus Facility Management System is used to manage real property information and processes, including a comprehensive asset inventory, space planning and management, lease administration, and preventive maintenance.
[35] eCOMET is software that provides data capture, analysis, capital renewal expenditure projections, and reporting.

- Evaluating an expanded effort to track the life cycle of key electrical components, which can inform a replacement strategy based on industry standards.

C. Performance Metrics

SCE currently tracks the following metrics:

- Number of buildings seismically retrofitted for both structural and non-structural purposes.
- Number of evacuation drills and average egress times of buildings.
- Number of emergency coordinators and life safety coordinators trained (relative to goal).
- Number of false fire alarms notifications as a proxy for effectiveness of FLS systems.

SCE is considering additional metrics:

- Age of critical FLS system components beyond manufacturer-specified useful life.
- Number of building electrical component failures per year.
- Percentage (relative to goal) of electrical component replacements per year.
- Percentage (relative to goal) of completed arc flash and infrared inspections.

IX. Appendix A

A. Summary of Buildings In Scope

Table IX-1 categorizes the different types of occupied buildings in terms of their primary function.

Table IX-1 – Summary of Buildings in Scope

Building Category	Category Description	Buildings in Category
Critical Facilities	Facilities containing any operation that, if interrupted, will cause a negative impact on business activities (e.g., data centers).	6
Generation	Buildings that support electric generation facilities owned by SCE (e.g., Big Creek and Mountain View).	4
Headquarters	Office buildings in the Rosemead General Office complex.	4
Office	Facilities primarily used to conduct business relating to administration, clerical services, and other client services not related to retail sales.	34
Service Center	Primarily houses the regional operation and planning functions of SCE's Transmission & Distribution and Customer Service organizational units.	63
Specialty/Garages	Buildings utilized for maintaining SCE's vehicle fleet, including cars, light trucks, cranes, line trucks and gas-powered equipment.	19
Manned Substation	Facilities at 31 substations that house employees (most roles relate to maintenance and operations).	34
Warehouse	Utilized for activities such as storing, testing and deploying electrical meters.	6
	Total	170

B. Supplemental Information on Risks Excluded from this RAMP Chapter

The number and diversity of buildings within SCE's portfolio made it challenging to narrow the scope of the analysis of this risk. Further, the age and condition of these buildings create a variety of hazards that SCE must address that could be unique to individual buildings.

To focus this RAMP chapter on the key safety risks facing our portfolio of occupied buildings, SCE evaluated, but ultimately decided against, several other drivers of risk to our buildings, including:

- Hazardous materials or substances (i.e., asbestos, lead, mold)
- Water inundation due to uncontrolled rapid release of water from a hydro dam

- Water inundation due to extreme rain or natural flooding
- Wildfire

1. Hazardous Materials or Substances

The greatest risk of exposure to hazardous materials, including Asbestos Containing Materials (ACM), occurs when the material is disturbed by intentional activities (e.g., construction) or by unintentional causes (e.g., earthquake). ACM is friable, meaning it is prone to breaking into small pieces when placed under stress or physical contact.

When the disturbance occurs as a result of intentional causes such as construction activities, mitigations are integrated into the activity that causes the disturbance. Prior to undertaking a project that will disturb existing exterior or interior building components, an environmental assessment is conducted to identify potential issues and to mitigate accordingly. For example, SCE's seismic retrofit activities include measures to protect workers and building occupants during construction activities that will disturb ACM or other hazardous materials.

The disturbance can occur due to unintentional situations, such as an earthquake. For the analysis presented in this chapter, the seismic modeling does not include potential impacts associated with ACM disturbance.

2. Water Inundation: Hydro Dam

Water inundation due to an uncontrolled rapid release of water from a hydro dam is not included in this chapter for two reasons. First, the Hydro Asset Safety chapter addresses this risk from the perspective of dams operated by SCE. Second, the safety risk posed by dams that SCE does not operate is either minimal or adequately mitigated (to the extent that SCE can mitigate the risk given that it does not operate the facilities).

SCE identified two facilities—the Santa Fe Dam and the Morris Reservoir—that are operated by other parties but could potentially cause harm to occupants of SCE buildings. The Morris Reservoir is upstream from the Santa Fe Dam, and each holds about 45,000 acre-feet of water. The flood inundation map[36] due to a failure of the Morris Reservoir indicates that SCE buildings would not be significantly impacted.

[36] "Inundation mapping" generally refers to a map that delineates the area that would be flooded by a particular flood event. It includes the ground surfaces downstream of a dam, showing the probable encroachment by water released because of: (a) failure of a dam, or (b) abnormal flood flows released through a dam's spillway and/or other appurtenant pathways for the water. Inundation maps for hydro dams and reservoirs are typically prepared by the facility operator following guidelines set by the regulating authority with jurisdiction. Morris map, *available at*

The inundation map for the Santa Fe Dam indicates that 11 SCE buildings could potentially be affected. However, due to the topography and/or distance from the failure source, the impact would be limited to operational inconvenience and water damage; injuries or fatalities are unlikely.

Because SCE does not operate the Santa Fe Dam or Morris Reservoir, the only mitigation available to SCE[37] is to make sure that it has sufficient ability to notify employees of a pending inundation risk and to implement protocols to respond to early notification or to seek protection onsite. SCE's Security Operations Center notification protocols already provide notifications and response protocols to mitigate these risks.

3. Water Inundation: Rain or Flood

Flooding due to natural causes was excluded due to low exposure, low potential for safety impacts, and redundancy with the Climate Change chapter.

A small number of the buildings in scope for this chapter are located in areas of potential risk due to natural flooding (e.g., flooding not caused by a dam failure). Ten SCE building are located within a 100 year-flood plain area as identified by FEMA.

The topography around these buildings naturally reduces the flood risk to a level of operational inconvenience without significant safety risk. For example, water might enter a building and require an area to be screened off for repairs, but it would not pose a safety risk. Additionally, if a flood were to occur, SCE's existing notification systems should provide adequate time to evacuate employees.

Finally, note that extreme rain events are covered as a driver in the chapter on Climate Change.

4. Wildfire

Wildfire is not addressed in this chapter to avoid redundancy with Chapter 12 (Climate Change) and Chapter 10 (Wildfire). The Climate Change chapter evaluates the risk that extreme wildfire events may pose to SCE assets, which includes SCE buildings. In the Wildfire chapter, wildfire is examined from the perspective of an ignition event that is associated with an SCE worker or SCE asset.

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https://www.ci.azusa.ca.us/DocumentCenter/View/5208/FloodZoneMap2010?bidId; Santa Fe Dam safety information, *available at* https://www.spl.usace.army.mil/Media/Fact-Sheets/Article/477342/dam-safety-program/

[37] SCE notes that, similarly to the operations of the hydro dams in its portfolio, the operators of the Santa Fe Dam and the Morris Reservoir are subject to significant public safety regulation.

5. Additional Comments on Fire Risk

Building fire incidents involving SCE buildings have been extremely rare. In 1980, a warehouse caught fire due to electrical issues. In 1994, a squirrel made contact with energized equipment at a switchyard, which led to a fire that damaged the roof of an SCE building. These two incidents represent the extent of past building fire incidents that SCE was able to identify (excluding wildfires and several small fires that did not involve buildings).

SCE analyzed fire risk by treating it as an outcome that would result from a preceding driver (i.e., the underlying cause of the fire). Table IX-2 shows nationwide data from the U.S. Fire Administration (USFA)[38] on the causes of nonresidential building fires in 2016. SCE used these categories to systematically assess which risk drivers with the potential to result in a fire outcome should be included in the chapter.

Table IX-2 – Nonresidential Building Fire Causes, U.S. (2016)

	Nonresidential Building Fires, U.S., 2016	% of Total
Cause not specified	32,400	33%
Cooking	28,900	30%
Unintentional, careless	10,700	11%
Intentional	9,000	9%
Heating	7,100	7%
Electrical	7,100	7%
Under investigation	1,600	2%
	96,800	100%

Of the fire causes specified in Table IX-2:

- Cooking was excluded due to lack of significant exposure.[39]
- The causes “Unintentional, careless” and “Intentional” are out of scope due to being a result of human action, not building failure. These types of actions are covered in the following chapters: (a) Employee, Contractor & Public Safety, which evaluates the consequences of acts performed by workers; and (b) Physical Security, which analyzes deliberate attempts to cause harm.

[38] USFA is an entity of FEMA.
[39] Four SCE buildings have commercial-level kitchens; each has fire suppression systems that meet compliance standards.

- Space heaters represent the largest source of fires[40] linked to heating-related causes by a substantial margin. To the extent that a fire could be caused by an individual using a personal space heater (which is generally not in conformance with SCE policy), the risk would fall within the scope of the chapter on Employee, Contractor & Public Safety.
- Electrical was included as described above.

[40] Non-Home Structure Fires By Equipment Involved In Ignition, NFPA, J. Hall, Jr., Feb. 2013, *available at* https://www.nfpa.org/-/media/Files/News-and-Research/Fire-statistics-and-reports/Building-and-life-safety/osnonhomefireequipment.ashx

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Southern California Edison Company

Risk Assessment and Mitigation Phase

Contact With Energized Equipment

Chapter 5

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

Southern California Edison (SCE) delivers electricity to over five million customers through our system of overhead conductor and underground cable. In this chapter, we will address an important safety risk associated with overhead conductor. This risk is members of the public coming into contact with energized overhead conductor. To do this, we developed a risk bowtie structure, quantified risk drivers, triggering events, outcomes, and consequences associated with it, and evaluated the effectiveness of existing controls and new mitigations at mitigating this risk.

SCE has developed three plans to address this risk. The Proposed Plan presented in this chapter best balances risk reduction, execution feasibility, and cost.

B. Scope

The scope of this chapter is defined in Table I-1.

Table I-1 – Chapter Scope

In Scope	• Contact by a member of the public with energized overhead distribution primary conductor, whether that conductor is a wire-down,[1] or remains intact.
Out of Scope	• Contact with energized equipment by SCE employee or contractors.[2] • Contact with energized equipment during attempted theft of SCE equipment or property. • Contact with substation or transmission equipment or conductor.[3] • Fire ignition associated with SCE Overhead Distribution Equipment.[4]

[1] For purposes of this chapter, wire-down events include situations where overhead conductor is physically on the ground as well as events where overhead conductor is not physically on the ground but is low enough to touch.
[2] Chapter 7 (Employee, Contractor, and Public Safety) addresses the risks associated with SCE employees and contractors contacting energized overhead conductor.
[3] This risk is discussed in Appendix B - Transmission and Substation Safety.
[4] This risk is discussed in Chapter 10 (Wildfire).

C. Summary Results

Table I-2 summarizes the controls and mitigations examined in this chapter, as well as the results of SCE's risk evaluation. The summarized material will be discussed in detail throughout this chapter.

Table I-2 – Summary Results (Annual Average over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Overhead Conductor Program (OCP)	X		X
C1a	Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor	X		
C2	Public Outreach	X	X	X
M1	Overhead Conductor Program (OCP) Utilizing Covered Conductor		X	
M2	Comprehensive Branch Line Fusing		X	X
M3	Targeted Underground Conversion			X
M4	Infrared Inspections	X	X	X
M5	Wildfire Covered Conductor Program	X	X	X
Mean (MARS)	*Cost Forecast ($ Million)*	$324	$338	$345
	Baseline Risk	7.91	7.91	7.91
	Risk Reduction (MRR)	0.89	0.93	0.93
	Remaining Risk	7.02	6.98	6.98
	Risk Spend Efficiency (RSE)	0.0027	0.0028	0.0027
Tail Average (MARS)	*Cost Forecast ($ Million)*	$324	$338	$345
	Baseline Risk	10.24	10.24	10.24
	Risk Reduction (MRR)	0.93	0.97	0.98
	Remaining Risk	9.31	9.27	9.27
	Risk Spend Efficiency (RSE)	0.0029	0.0029	0.0028

Figures represent 2018 - 2023 annual averages.

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled this report, and are addressed in Section IV.

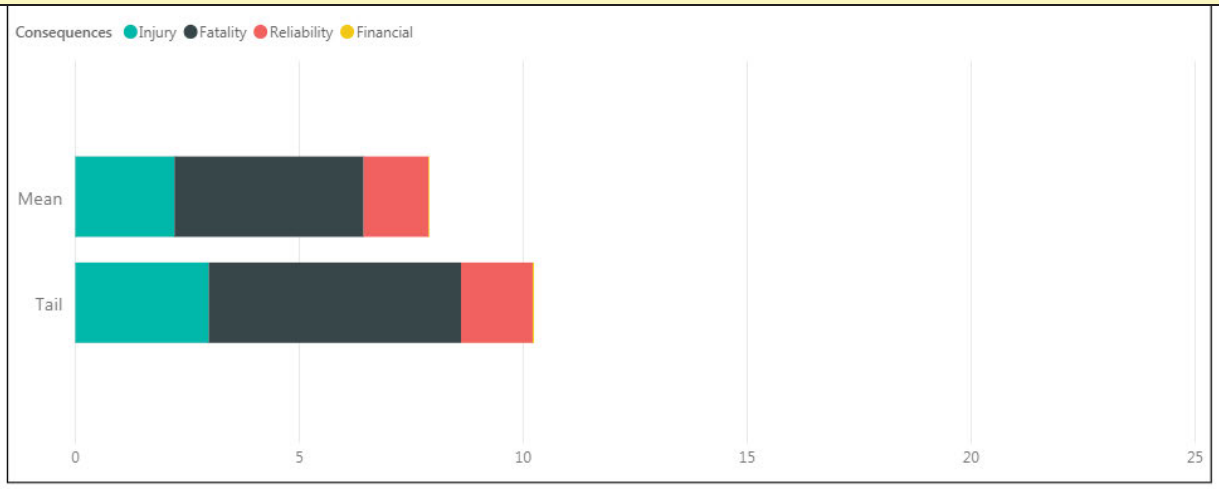
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 below illustrates the composition of the baseline risk. This figure illustrates that the majority of this risk is associated with serious injuries and fatalities. Reliability impacts are also caused by this risk.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS is 100.

II. Risk Assessment

A. Background

SCE's electrical system includes approximately 106,000 conductor miles of primary overhead distribution conductor. This conductor is installed on distribution poles throughout our service territory. The conductor transmits electricity from distribution substation to distribution substation, and from distribution substation to end-use customers. In areas served by overhead infrastructure, energized distribution conductor is present on nearly every street, alley, thoroughfare, and residential property.

Exposure to the elements, contact with metallic balloons, vegetation intrusion, and windborne debris could all potentially cause an overhead conductor fault and wire-down event. SCE's distribution system is constructed with protection equipment that stops the flow of electricity when a foreign object contacts the line and causes a fault. If the fault is temporary and has not resulted in damage, electricity flow can typically be restored relatively quickly (in seconds or minutes) through an automatic operation referred to as a circuit "reclose."[5] If the fault is permanent or has resulted in damage to infrastructure, then the electricity flow will remain interrupted. This condition is referred to as a circuit "lockout," and requires deploying field personnel to locate and repair the problem.

On a daily basis across SCE's service territory, protection devices successfully open and either reclose or lockout circuits. This maintains reliability while reducing the need to deploy resources to manually reclose line sections. However, SCE has experienced several fatalities as a result of conductor failing in service, falling to the ground, remaining energized, and being contacted by members of the public.

In recent years, SCE has recognized that a more comprehensive program was necessary in order to adequately address the safety risks associated with overhead conductor failure. As a result, in our 2018 GRC[6] SCE proposed a new Overhead Conductor Program (OCP) to replace and mitigate at-risk overhead conductor.

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[5] Studies have shown that more than half of faults on overhead distribution systems are temporary faults, or faults that clear themselves without needing additional repairs. Common examples of temporary faults include lightning, wind-driven conductor slapping, and animal contact. In reclosing, a protective device opens to clear a fault and then waits for a pre-determined period of time (say, 15 seconds) before attempting to close. If the fault was indeed temporary, then the protective device closes again, re-energizing the circuit and restoring service to customers served by the circuit. In such case, the circuit has successfully "reclosed."

[6] *See* SCE's Test Year 2018 General Rate Case, A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51.

SCE also presented its initial risk analysis of overhead conductor failure in its 2018 GRC.[7] Specifically, SCE used this risk analysis to evaluate a wide range of mitigation alternatives as well as to shape the scope definition for the mitigations selected. SCE analyzed the equipment installed on the distribution system to identify the types of conductor most commonly involved in overhead conductor failure, or a wire-down event. This effort included additional engineering review of wire-down events; as a result, SCE has made changes to its engineering and design standards to reduce the risk of wire-down events.[8] SCE also reached out to other utilities in California to understand their experience with wire-down events, including drivers, programs, mitigations, and other findings.

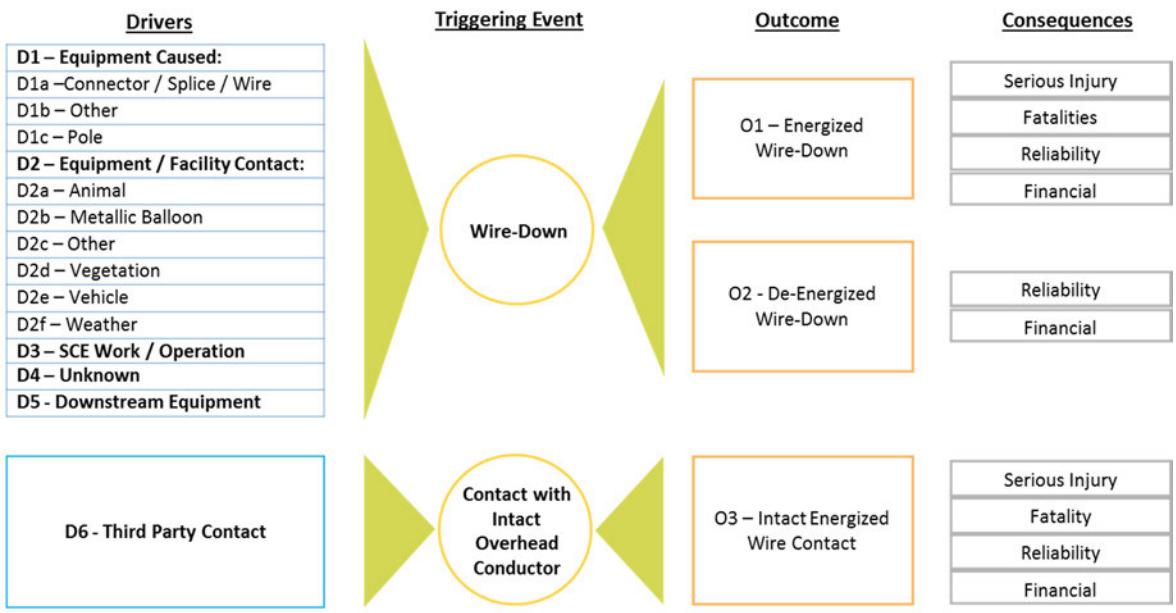
Moreover, SCE implemented changes to improve how it tracked and captured event-specific details for overhead conductor failures that resulted in wire falling to the ground. The information is now housed in SCE's Wire-Down (WD) database. We used this information, combined with outage information from our Outage Database and Reliability Metrics (ODRM) system, to identify and quantify drivers, outcomes, and consequences of wire-down events.

In addition to risks associated with wire-down events, there are also risks associated with human contact with intact energized conductor. This can include high-risk workers such as tree trimmers and agricultural workers. There are distinct differences between the risks associated with contact with energized wire-down and risks associated with contact with overhead intact energized conductor. Contact with energized wire-down, by definition, takes place in the presence of equipment failure or fault, while contact with energized intact overhead conductor takes place in the absence of equipment failure or fault.

Therefore, to evaluate the Contact with Energized Equipment risk, SCE has constructed two risk bowties as shown in Figure II-1. These bowties identify two triggering events for this risk: 1) Wire-Down, and 2) Contact with Intact Conductor.

[7] *See* A.16-09-001, Exhibit SCE-02, Vol. 1, pp. 41-44.
[8] Changes to engineering and design standards include the standard installation of a minimum 1/0 AWG for overhead distribution tap lines and 336 ACSR AWG for overhead distribution mainlines for all new installations.

Figure II-1 – Contact with Energized Equipment Risk Bowties



While the risks of Contact with Energized Equipment and Wildfire are distinct, similarities exist between the drivers in the Wire-Down bowtie compared to the drivers in the Wildfire bowtie as shown in Chapter 10 (Wildfire). Although these risks are analyzed independently within each chapter, we discuss the interrelation between Contact with Energized Equipment and Wildfire controls and mitigations in Sections III and IV below.

B. Driver Analysis

SCE identified five primary drivers that lead to a wire-down, the triggering event in the first bowtie. As detailed below, we were able to subdivide two of these drivers (D1 – Equipment Caused and D2 – Equipment/Facility Contact); this greater granularity helped us better understand the causes of this risk.

SCE identified one primary driver that leads to the Contact with Intact Conductor, the triggering event in the second bowtie.

Figure II-2 shows the projected annual frequency counts for each driver across the two bowties. SCE used its internal Wire-Down database[9] to identify the frequency of drivers D1

[9] SCE's Wire-Down database includes several data fields, encompassing conductor material, conductor type, conductor size, event date, circuit name, voltage, cause category, cause type, trigger, structure number, and primary factor.

through D5, which are associated with the first bowtie that address this risk. Data for the frequency of D6 (Third Party Contact), which is associated with the second bowtie, comes from SCE internal records regarding injuries or fatalities involving overhead equipment.[10]

Figure II-2 – 2018 Projected Driver Frequency[11]

Name	Freq	Frequency
D1 - Equipment Cause	206	
D2 - Equipment / Facility Contact	773	
D3 - SCE Work / Operation	7	
D4 - Unknown	168	
D5 - Downstream Equipment	0	
D6 - Third Party Contact	5	

1. D1 – Equipment Cause

The "Equipment Cause" driver represents instances where SCE's equipment fails in service or fails to operate as designed, resulting in a wire-down event. Sub-categories of drivers identify the specific type of equipment that fails.[12] A summary of the annual frequencies of this driver and its sub-drivers is provided in Table II-1 below. This table provides frequencies both as a percentage of this driver category (i.e., D1) and as a percentage of all triggering events (i.e., D1 through D6 combined).

[10] Such events are reported to the Commission in compliance with D.06-04-055 and Resolution E-4184.
[11] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment).*
[12] Please note that the RAMP risk model treats all D1 drivers as a single input, rather than modeling each of the individual sub-drivers separately.

Table II-1 – D1 (Equipment Cause) Frequencies			
Driver Name	**Annual Frequency**	**Percentage (Category)**	**Percentage (All Triggering Events)**
D1a Connector/Splice/Wire	130	63%	11%
D1b Other	65	32%	6%
D1c Pole	11	5%	1%
D1 Equipment Cause	**206**	**100%**	**18%**

a. D1a – Connector / Splice / Wire

Connectors and splices are two different types of devices used as a connection for overhead conductor. Overhead conductor, or wire, is attached to other equipment with a connector, and spans of conductor are connected to other spans of conductor with a splice. Both types of devices are subject to degradation due to exposure to the elements and can be damaged due to faults, particularly with elevated short circuit duty[13] on the circuit. In the presence of faults, these equipment types can overheat and melt, causing the overhead conductor to fall to the ground.

a. D1b – Other

This driver includes all equipment drivers other than poles and connectors / splices / wires. Examples include failure of transformers, insulators, lightning arrestors, and cross arms. These types of equipment can deteriorate from age, use, and exposure to the elements.

b. D1c – Pole

Pole failures that lead to wire-down events typically occur when there is deterioration at the top of pole. Pole deterioration can take place at any location on a pole. Unless the deterioration is visible, SCE's intrusive pole inspection program and pole loading assessments cannot effectively test for, or detect, deterioration at the top of the pole. Pole failure due to vehicle collision is not included in this sub-driver, but is included in Sub-Driver D2e – Vehicle as described below.

[13] Short Circuit Duty (SCD) indicates the relative strength of a system, typically measured by the fault current (in amps) that the system can supply at any location within the system. For older overhead wire installations, existing levels of SCD can result in increased risk of conductor damage during fault conditions, though it is not currently possible to determine the extent of conductor damage on in-service overhead conductor from previous faults.

2. D2 – Equipment / Facility Contact

The "Equipment/Facility Contact" driver represents instances where a foreign object has made contact with SCE's overhead conductor, resulting in the conductor failing. This driver category includes sub-categories which identify the specific external factor that caused the equipment to fail.[14] A summary of the annual frequencies of this driver category and each sub-category is provided in Table II-2 below. This table provides frequencies both as a percentage of this driver category (i.e., D2) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-2 – D2 (Equipment / Facility Contact) Frequencies

Driver Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D2a Animal	53	7%	5%
D2b Metallic Balloons	111	14%	10%
D2c Other	39	5%	3%
D2d Vegetation	171	22%	15%
D2e Vehicle	206	27%	18%
D2f Weather	193	25%	17%
D2 Equipment/Facility Contact	**773**	**100%**	**67%**

a. D2a – Animal

Animals, such as birds and squirrels, are frequently seen sitting or walking on overhead conductors. In some instances, an animal makes the fatal move of contacting two phases of a circuit or contacting one phase of a circuit and a grounded portion of the circuit, causing a fault. Similar to faults caused by a metallic balloon, the result can be circuit damage, overheating, or fire, or explosion.

b. D2b – Metallic Balloons

Foil, foil-lined or metallic balloons can potentially damage overhead electrical equipment because of their conductivity. Current California law[15] has recognized this, and requires that all helium-filled metallic balloons be weighted to prevent escape and potential contact with overhead electrical facilities. When a metallic balloon contacts overhead lines, it can create a short circuit. The short circuit can trigger circuit damage, overheating, fire, or an explosion.

[14] Please note that the RAMP risk model treats all D2 drivers as a single input, rather than modeling each of the individual sub-drivers separately.
[15] *See* Cal. Penal Code § 653.1. (Foil Balloon Law).

c. D2c – Other

The Other sub-category includes overhead conductor failures that are driven by malicious mischief or other actions by the public. This includes gunshot damage to conductors and contact from various objects such as drones.

d. D2d – Vegetation

The vegetation sub-category includes overhead conductor failures driven by contact with vegetation. Vegetation may grow into the primary lines when homeowners plant climbing vines to hide a power pole, or when a branch or tree breaks and falls into SCE's overhead conductor. Airborne vegetation, particularly palm fronds, can also come in contact with SCE's overhead conductor, resulting in damage.

e. D2e – Vehicle

The vehicle sub-category includes overhead conductor failures driven by motorized vehicles. This can occur when a passenger car, moving van, or garbage truck collides with our electrical equipment. The failure can result from overhead lines "slapping" together due to the impact of the collision, or from a pole being knocked over or broken from the impact.

f. D2f – Weather

The weather sub-category includes contact with overhead lines as a result of weather conditions, including wind and lightning. During windy conditions, debris is blown into the lines. This results in outcomes ranging from momentary outages to downed conductor. This driver is identified by SCE personnel based on evidence available at the time of the event, such as debris in the lines, pitting of the conductor, or burned matter in proximity to the outage during declared storm events.[16]

3. D3 – SCE Work / Operation

The SCE Work / Operation driver includes activities where SCE or its contractors were responsible for a wire-down. This includes improperly operating equipment during construction, repair, switching, or other activity. The distinction between this driver and the risks assessed in the Worker Safety chapter is that the events in this chapter include consequences associated with damage to SCE infrastructure, but not the consequences associated with any injuries to SCE workers or contractors that may occur. A summary of the annual frequency of this driver category

[16] A storm event is defined as an SCE distribution circuit outage(s) resulting from wind, rain, lightning, heat, or fire.

is provided in Table II-3 below. This table provides frequencies both as a percentage of this driver category (i.e., D3) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-3 – D3 (SCE Work / Operation) Frequencies

Driver Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D3 SCE Work/Operation	**7**	**100%**	**Less than 1%**

4. D4 – Unknown

In some circumstances, the cause of a wire-down event is not identifiable when SCE personnel arrive at the site. This can occur for a variety of reasons. Examples include emergency personnel securing the area prior to SCE's arrival, or the offending object being blown or thrown from the location. It is also possible that there is no apparent cause for the failure, and rather than entering a "best guess," the cause is simply categorized as unknown. A summary of the annual frequency of this driver category is provided in Table II-4 below. This table provides frequencies both as a percentage of this driver category (i.e., D4) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-4 – D4 (Unknown) Frequencies

Driver Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D4 Unknown	**168**	**100%**	**14%**

5. D5 - Downstream Equipment

A Downstream Equipment-caused failure is the result of failure of other equipment installed on or connected to the circuit. Simply stated, if there are two pieces of equipment installed on a circuit, the piece of equipment farther from the substation is "downstream" of the piece of equipment closer to the substation. When the downstream equipment fails, high levels of fault current travel a path from the substation through the distribution circuit to the point of fault. These high levels of fault current can damage upstream equipment or conductor along the path, increasing both the immediate and the future probability of equipment failing.

SCE has included D5 in the bowtie shown above because, in recent years, SCE has experienced specific instances of upstream wire-down events associated with downstream faults. These faults can sometimes be very difficult to identify separately, and are implicitly included in D1, D2, and D4 previously described. Although we included Driver D5 in the bowtie

for visibility, Driver D5 was modeled with a zero event per year frequency to avoid duplicate representation of the associated risk. A summary of the annual frequency of this driver category is provided in Table II-5 below. This table provides frequencies both as a percentage of this driver category (i.e., D5) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-5 – D5 (Downstream Equipment) Frequencies

Driver Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D5 Downstream Equipment	**modeled as zero annual frequency (implicitly included in other equipment failure drivers)**		

6. D6 - Third Party Contact with Intact Lines

D6 includes events where an individual makes contact with energized intact overhead conductor. For example, this driver includes events where a tree trimmer touches an energized conductor with a pruning tool. This contact occurs when there has been no failure of overhead equipment.

The data for Third Party Contact with Intact Lines frequency is based on SCE internal records regarding injuries or fatalities involving overhead equipment. The events which were identified as contact with intact conductor were included in the count for this driver. SCE identified an average of approximately five events per year from 2008 through 2016. A summary of the annual frequency of this driver category is provided in Table II-6 below. This table provides frequencies both as a percentage of this driver category (i.e., D6) and as a percentage of all triggering events (i.e., D1 through D6 combined).

Table II-6 – D6 (Third Party Contact) Frequency

Driver Name	Annual Frequency	Percentage (Category)	Percentage (All Triggering Events)
D6 Third Party Contact	**5**	**100%**	**Less than 1%**

C. Triggering Event

SCE has identified two triggering events for the risk of Contact with Energized Equipment.

1. **Wire-Down** – This results in conductor falling to the ground, or becoming disconnected from the system in a manner that would allow the public to come in contact with it. This triggering event is shown in the first bowtie

in Figure II-1. Based on SCE's Wire-Down database, this triggering event has an average frequency of 1,154 events per year.

2. **Contact with intact overhead conductor** – This event occurs when an individual, or third party, makes contact with SCE's overhead conductor while the conductor is operating and situated as designed. Based on SCE internal records, this triggering event has an average frequency of five events per year.

D. Outcomes & Consequences

SCE identified three outcomes that represent the basic conditions existing when overhead conductor fails in service and falls to the ground, or when the public makes contact with intact overhead conductor. These outcomes, and their associated likelihood of occurrence, are shown in Figure II-3.

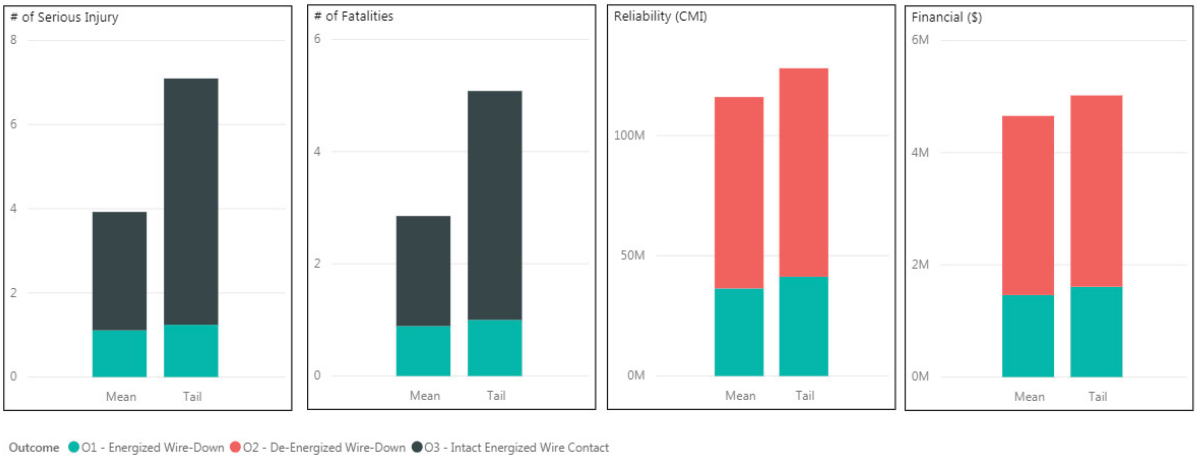
Figure II-3 – 2018 Outcome Likelihood[17]

Name	%	Percent
O1 - Energized Wire-Down	31.3 %	
O2 - De-Energized Wire-Down	68.3 %	
O3 - Intact Energized Wire Contact	0.4 %	

Further, Figure II-4 illustrates the composition of the modelled baseline risk in terms of each consequence. As shown, the primary safety impact of this risk results from the occurrence of O3 (Intact Energized Wire Contact). Notably, O1 (Energized Wire-Down), also results in safety impacts, and also contributes to reliability and financial impacts. The sections that follow detail the inputs used to derive these results.

[17] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment)*.

Figure II-4 – Modelled Baseline Risk Composition by Consequence (NU)



1. O1 – Energized Wire-Down

This outcome occurs when a wire-down event has taken place, protective devices have not detected the wire-down condition, and manual intervention is required to interrupt the energized wire-down event. SCE's distribution system is designed and built with protection to stop the flow of electricity under fault conditions, to lockout under conditions of permanent faults or equipment damage, and to reclose under conditions of temporary faults which do not cause infrastructure damage. This protection is intended to prevent accidental contact with overhead conductor by de-energizing the conductor prior to or immediately upon contact with the ground. This is successful when there is enough fault current to be detected by system protective devices.

However, under certain conditions, wire-down events can be difficult to detect by protective devices. For example, this can occur when a wire-down event takes place on high-resistance surfaces such as asphalt, concrete, or very sandy or rocky soils. These conditions are referred to as high impedance fault conditions and can result in fault current magnitudes lower than that what can readily be detected. High impedance fault conditions with wire-downs may not be automatically cleared by protective devices. These conditions may need to be detected through other means such as customer calls, 911 calls, or circuit patrol activities. These conditions also may need to be interrupted by manual intervention of system operators. A summary of the consequences modeled for O1 (Energized Wire-Down) is shown in Table II-7.

Table II-7 – Outcome 1 (Energized Wire-Down): Consequence Details[18]

Outcome 1		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*	Incidents involving SCE overhead conductor that resulted in serious injuries, from 2008 – 2016.	Incidents involving SCE overhead conductor that resulted in fatality, from 2008 – 2016.	Actual wire-down outage events as analyzed within SCE ODRM Database.	Average cost of equipment repair resulting from wire-down events.
Model Outputs *(Annual Average)*	NU - Mean	1.1	0.9	36,434,141	$1,461,503
	NU - Tail Avg	1.2	1.0	41,273,501	$1,609,341

2. O2 – De-Energized Wire-Down

O2 considers wire-down events where protective devices have detected the wire-down condition and automatically de-energized the wire-down event. As described previously, SCE's distribution system is built with protection designed to stop the flow of electricity under fault conditions, to lockout under conditions of permanent faults or equipment damage, and to reclose under conditions of temporary faults that do not cause infrastructure damage. This protection is intended to prevent accidental contact with overhead conductor by de-energizing the conductor prior to or immediately upon contact with the ground. This is successful when there is enough fault current to be detected by system protective devices.

As a result of the protective device operation, safety impacts are not typically associated with this outcome.[19] Therefore, SCE has not modeled any safety consequences in this outcome. A summary of the consequences modeled for O2 (De-Energized Wire-Down) is shown in Table II-8.

[18] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

[19] Some de-energized wire-down events could be described as "briefly-energized" events. This would be the case where wire is on the ground but only in an energized state during the response time of circuit protective devices. These protective devices typically clear faults in fractions of a second, so the relative risks of "briefly-energized" wire-down events are expected to be low. SCE intended to include a separate "briefly-energized" outcome for this risk analysis, but found that inadequate data exists to identify the number of times that de-energized wire-down events also have a "briefly-energized" characteristic.

Table II-8 – Outcome 2 (De-Energized Wire-Down): Consequence Details[20]

Outcome 2		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	N/A	N/A	Actual wire-down outage events as analyzed within SCE ODRM Database.	Average cost of equipment repair resulting from wire-down events.
Model Outputs *(Annual Average)*	NU - Mean	N/A	N/A	79,598,077	$3,192,980
	NU - Tail Avg	N/A	N/A	86,711,104	$3,409,468

3. O3 – Intact Energized Wire Contact

This outcome occurs when human contact with intact overhead conductor results in serious injury or fatality, and/or and damage to SCE's electrical system. This can occur when overhead conductor is contacted by someone working in close proximity to the line, such as a tree trimmer, making contact. Reliability and Financial consequences have been excluded from modeling. A summary of the consequences modeled for Outcome O3 (Intact Energized Wire Contact) is shown in Table II-9.

[20] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

Table II-9 – Outcome 3 (Intact Energized Wire Contact): Consequence Details[21,22]

Outcome 3		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*	Incidents involving SCE overhead conductor that resulted in serious injuries, from 2008 – 2016.	Incidents involving SCE overhead conductor that resulted in fatality, from 2008 – 2016.	N/A	N/A
Model Outputs *(Annual Average)*	NU - Mean	2.8	2.0	N/A	N/A
	NU - Tail Avg	5.9	4.1	N/A	N/A

[21] As SCE's ODRM does not adequately capture reliability impacts associated with this outcome, SCE does not model reliability for this outcome as part of this RAMP analysis. SCE expects reliability impacts to be small.

[22] Please refer to WP Ch. 5, pp. 5.1 – 5.2 *(Baseline Risk Assessment)* for further details on these data sources and evaluation methods.

III. Compliance & Controls

SCE has programs and processes in place that serve to control the risk today. Four of these controls are compliance activities, and accordingly not modeled in this risk analysis. In addition to these compliance activities, three additional controls are modeled in this risk analysis. These compliance activities and controls are shown in Table III-1.

Table III-1 – Inventory of Compliance and Controls[23,24]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	Distribution Deteriorated Pole Remediation Program and Pole Loading Program (PLP) Replacements	Not Modeled	Not Modeled	Not Modeled	$ 273.9	$ 30.9
CM2	Vegetation Management	Not Modeled	Not Modeled	Not Modeled	$ -	$ 84.3
CM3	Overhead Detailed Inspection, Apparatus Inspections, and Preventive Maintenance	Not Modeled	Not Modeled	Not Modeled	$ -	$ 36.0
CM4	Intrusive Pole Inspections and Pole Loading Assessments	Not Modeled	Not Modeled	Not Modeled	$ -	$ 6.0
C1	Overhead Conductor Program (OCP)	D1a-b, D2a-d,f	-	-	$ 138.7	$ -
C1a	Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor	D1a-b, D2a-d,f	O1	S-I, S-F	$ -	$ -
C2	Public Outreach	-	O1, O3	S-I, S-F	$ -	$ 5.1

Consequence Abbreviation: Serious Injury - S-I; Fatality - S-F; Reliability - R; Financial - F

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

A. CM1 – Distribution Deteriorated Pole Remediation Program and Pole Loading Program (PLP)

SCE's Distribution Deteriorated Pole Remediation Program[25] captures the costs to replace or stub[26] distribution poles which have failed an intrusive pole inspection. The Distribution Pole Loading Program (PLP)[27] captures costs to assess all poles within SCE's service territory and

[23] Please refer to WP Ch. 5, pp. 5.3 – 5.11 *(Control & Mitigation Risk Reduction Effectiveness)* and WP Ch. 5, pp. 5.12 – 5.22 *(Mitigation Effectiveness Workpaper).*
[24] Note that for simplicity, SCE shows all recorded costs for OCP in C1 (and not also in C1a). While SCE has not historically used covered conductor in the OCP program, C1a will further the objectives of OCP (just using a different technology).
[25] *See* A.16-09-001, Exhibit SCE-02, Vol. 9, pp. 30-44.
[26] Stub – steel stubbing which reinforces the base of the pole (please see A.16-09-001, Exhibit SCE-02, Vol. 9, p. 34).
[27] *See* A.16-09-001, Exhibit SCE-02, Vol. 9, pp. 10-29.

replace those which fail the applied wind-loading measurement. The costs for both programs are recovered through SCE's Pole Loading and Deteriorated Pole Balancing Account (PLDPBA).

These two programs proactively identify poles that represent an increased probability of pole failure. Through these programs, SCE takes action to replace such poles with new assets that meet pole design standards and criteria. Thus, this compliance control reduces the frequency of pole-related drivers of wire-down events.

B. CM2 – Vegetation Management

Vegetation Management including pruning and removing trees that are in proximity to transmission and distribution high-voltage lines. Vegetation Management also encompasses weed abatement around select overhead structures that may pose a hazard to power lines. These activities are mandated by regulation. This compliance-related work is distinct from the incremental Expanded Vegetation Management mitigation discussed in the Wildfire Chapter. [28]

SCE manages vegetation in accordance with several regulations, including General Orders (GO) 95 Rules 35 and 37, Public Resources Code Sections 4292 and 4293, and FERC FAC-003-2. These regulations require SCE to manage vegetation near its wires. SCE engages a contractor to trim and remove trees and weeds, and handle other activities, to comply with these requirements.

All of the trees in inventory are inspected annually. During these inspections, any trees or vegetation that need to be remediated to maintain the required distances from high-voltage lines are then scheduled to be pruned or removed. In addition, hazard trees, such as overhangs in high fire areas, and damaged or diseased trees are also identified for pruning or removal. Sometimes SCE must trim trees more frequently to continue to meet the Commission's requirements tree-to-line clearances between annual trim cycles. Fast-growing species, or trees in areas designated as high-risk for wildfires, may need more frequent pruning to meet the Commission standards. SCE is exploring an Expanded Vegetation Management program for high fire risk areas, as described in detail in the Wildfire Chapter.

Besides the vegetation management efforts described above, SCE also removes dead, dying, and diseased trees impacted by Bark Beetle infestation or resulting from California's Drought Order. Because of the drought emergency, SCE increased work activities associated with inspecting and removing dead, dying, or diseased trees that could fall on or contact SCE's electrical facilities. Unlike trees located near power lines that must be trimmed to prevent

[28] This compliance control is also represented in the Wildfire chapter as CM1. As such, this compliance control serves to affect the risk of both Contact with Energized Equipment and Wildfire.

encroachment, large dead or dying trees can be located outside of the right-of-way and still fall into power lines. This significantly increases the number of trees that can pose a hazard to our customers and the communities we serve.

C. CM3 – Overhead Detailed Inspection, Apparatus Inspections, and Preventative Maintenance

SCE's Overhead Detailed Inspection, Apparatus Inspections, and Preventative Maintenance are activities included under SCE's Distribution Inspection and Maintenance Program (DIMP). The goal of DIMP is to meet the requirements of GO 95, 128, and 165 in a way that: (1) follows sound maintenance practices; (2) enhances public and worker safety and maintains system reliability; and (3) delivers overall greater safety value for each dollar spent by allowing SCE to focus its limited resources on higher priority risks. These activities address all distribution overhead assets in the SCE system.

DIMP enables us to prioritize work based on the condition of each facility or piece of equipment and its potential for impact on safety and reliability, considering various factors such as facility or equipment loading, location, accessibility, and climate. DIMP enables SCE to prioritize resources effectively and efficiently to remediate conditions that potentially pose higher risks. This approach follows the Commission's direction under GO 95 and a memorandum of understanding between SCE and the CPUC's Safety and Enforcement Division.

DIMP has three maintenance priority levels. During inspections, SCE inspectors identify and rate conditions observed considering the factors discussed previously. Highest priority items requiring immediate action are assigned Priority 1. Priority 2 items do not require immediate action, but require corrective action within a specified time period. Priority 1 and Priority 2 items may be fully repaired or temporarily repaired and reclassified as a lower priority item. Priority 3 items are lower priority items that involve little or no safety or reliability risk. SCE responds to Priority 3 conditions by taking action at or before the next detailed inspection, which may include re-inspection, reassessment, or repair. These maintenance priorities are also utilized by Troublemen when responding to trouble calls and emergency situations. A summary of the DIMP maintenance priority levels is provided in Table III-2.

Table III-2 – Summary of Maintenance Priority Levels

Category	Safety/Reliability Issue Identified	Condition Details	Action
Priority 1	Yes	Immediate action required	Same day/immediate action
Priority 2	Yes	Immediate action not required	Action within 0-24 months (non High Fire Areas) Action within 0-12 months (High Fire Areas)
Priority 3	No	Specific GO 95/128 issue identified	Action at or before next detailed inspection
none	No	No GO 95/128 issue identified	Monitor condition during course of inspection cycles

These activities proactively identify conditions of existing assets that require mitigation to prevent failure. This compliance control performs such mitigations and reduces the frequency of equipment-related drivers of wire-down events.

D. CM4 – Intrusive Pole Inspections and Pole Loading Assessments

These programs involve inspecting or assessing existing distribution poles to execute the activities described in the Distribution Deteriorated Pole Remediation Program and PLP described above. As an enabling activity for compliance control CM1 above, this control helps reduce the frequency of pole-related drivers of wire-down events.

1. Intrusive Pole Inspections

SCE established the distribution pole inspections program to comply with GO 165, which became effective in 1997. GO 165 requires intrusive inspections for all poles at least 15 years old to be completed within 10 years of program inception. Thereafter, it requires all poles to be intrusively inspected by the time they are 25-years old and then re-inspected at least once every 20 years. SCE completed its first cycle of intrusive inspections in 2007.

GO 165 defines intrusive inspections as “involving movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading.” “Intrusive” inspections involve drilling into the pole’s interior to identify and measure the extent of internal decay, which is typically undetectable with external observation alone. SCE’s inspection standards describe six types of inspections satisfying this definition which apply different combinations of digging, boring, and sounding depending on the type of pole and its setting.

Intrusive inspectors may also perform visual inspection on poles that are in the inspection grid but that are younger than 15 years old, or that have already had an intrusive

inspection within the last 10 years, to look for signs of obvious external damage such as damage from vehicles or woodpeckers.

2. Pole Loading Assessments

Pole loading assessments are performed to determine a pole's safety factor. Pole loading assessments require a field assessment and a desktop analysis to calculate each pole's safety factor. Inputs include the physical attributes of the pole, its attachments, and local weather conditions. The field assessment measures or validates the pole's attributes (such as species and type) and the size and equipment it supports.

E. C1 – Overhead Conductor Program (OCP)

SCE's OCP includes both reconductoring and installation/replacement of Branch Line Fuses.[29] OCP is an existing control that SCE began performing in 2015. In SCE's 2018 GRC[30] the Overhead Conductor Program (OCP) was proposed as a new program to implement these mitigations together and address the public safety risk associated with wire-down events.

Central to OCP strategy is an understanding of short circuit duty (SCD). Generally, SCD indicates the relative strength of a system, typically measured by the fault current (in amps) that the system can supply at any location within the system. For older overhead wire installations, existing levels of SCD can result in increased risk of conductor damage during fault conditions, although it is not currently possible to determine the extent of conductor damage on in-service overhead conductor from previous faults.

The OCP addresses this problem by reconductoring smaller-gauge wire to larger-gauge wire that reduces the risk of conductor damage during fault conditions, and installing new protective devices such as branch line fuses where appropriate. The OCP also addresses other deteriorated or corroded equipment such as crossarms, poles, and connection hardware.

Consistent with existing OCP scoping practice, C1 is modeled as including the use of bare overhead conductor and representing 100% of the OCP expenditures for years 2018 through 2020. Because SCE also anticipates future use of covered conductor in non-High Fire Risk Areas (HFRA), C1 is modeled as representing only 90% of the OCP expenditures for years 2021 through 2023. The remaining 10% of the OCP expenditures for years 2021 through 2023 is included in C1a "Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor" as described below. At this time, SCE does not know the exact percentages of bare versus covered

[29] Branch Line Fuses are protective devices that are designed to clear faults on the system.
[30] *See* A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51.

conductor for future OCP projects in non-HFRA. The 90% and 10% values for years 2021-2023 are assumed percentages for modeling purposes.

1. Drivers Impacted

The OCP impacts the triggering event frequency associated with Drivers D1 (Equipment Cause), and D2 (Equipment /Facility Contact).[31]

The OCP will reduce the frequency of wire-down events associated with D1 by reducing the frequency of faults. This is because the OCP replaces small, spliced, or damaged conductor with larger, more resilient conductor. The OCP will reduce the frequency of wire-down events associated with Driver D2 not by reducing the frequency of faults, but by reducing the number of faults that lead to wire-down events. Faults listed in D2 are external events that will continue to occur regardless of the OCP. However, the upgrades we perform in OCP will create a more resilient system that will be less susceptible to damage as a result of such faults.

2. Outcomes and Consequences Impacted

The OCP will not impact outcomes or consequences in the risk model.

F. C1a – Overhead Conductor Program (OCP) Using Targeted Covered Conductor

This control assumes that going forward, a small portion of the OCP will be built using covered overhead conductor on a targeted basis.

Covered conductor is overhead conductor enclosed in a high-density polyethylene covering, and is intended to prevent faults caused by contact from tree and other vegetation, contact with metallic balloons, and other types of contact. Use of covered conductor would help preventing certain types of faults, and therefore would reduce wire-down events and intact conductor failures. Covered conductor's partial insulation also provides some degree of protection against safety incidents associated with humans contacting overhead lines.

C1a assumes that SCE will implement a change in the OCP scoping tenets to identify targeted locations appropriate to be built using covered conductor instead of bare conductor. "Targeted locations" refers to locations with higher expectation of faults on bare conductor due to contact with foreign objects such as balloons, vegetation, and animals. SCE has not yet defined these exact scoping tenets, so SCE assumes that these tenets would begin influencing scope in 2021. Until we have more definitive information around these scoping tenets, SCE assumes that C1a would represent 10% of the OCP expenditures in years 2021 through 2023.

[31] Specifically, C1 affects the following sub-drivers: D1a (Connector/Splice/ Wire), D1b (Other), D2a (Animal), D2b (Metallic Balloon), D2c (Other), D2d (Vegetation), and D2f (Weather).

This 10% assumption is specific to non-HFRA and is mutually exclusive from what is proposed in the Wildfire Chapter.

1. Drivers Impacted

The OCP using Targeted Covered Conductor impacts the same drivers addressed by the OCP, namely: D1 – Equipment Cause, and D2 – Equipment / Facility Contact.[32] However, the OCP using Targeted Covered Conductor assumes different mitigation effectiveness for specific drivers than the OCP. The most significant difference is that the OCP using Targeted Covered Conductor assumes much higher mitigation effectiveness for animal, metallic balloon, and vegetation-related drivers (D2a, D2b and D2d respectively).

2. Outcomes and Consequences Impacted

Contact with covered conductor is less likely to result in serious injury or fatality than contact with bare conductor in an energized wire-down event. Therefore, this control was modeled as reducing the safety consequences associated with Outcome O1 (Energized Wire-Down).

Contact with covered conductor is also less likely to result in serious injury or fatality than contact with bare conductor when an event involves contact with intact overhead conductor (O3). However, as shown in Figure II-3, O3 has a significantly smaller outcome percentage than either O1 or O2. Therefore, as a simplifying assumption and for purposes of this initial RAMP report, SCE did not model any impact on the safety consequences associated with Outcome O3.

G. C2 – Public Outreach

This control includes two activities: (1) Public Safety Outreach, and (2) At-Risk Worker Safety Outreach.

Public Safety Outreach focuses on educating and informing the public on actions to take and avoid when encountering a downed electrical wire. Examples of these outreach efforts include: billboards, television and radio announcements, signage on SCE vehicles, community outreach, information distributed at community events. SCE personnel also work with elementary schools to teach children proper safety around electrical lines. This interaction with young students encourages them to share the information with their families, providing greater reach for the message of safety around energized lines.

[32] Specifically, C1a affects the following sub-drivers: D1a (Connector / Splice / Wire), D1b (Other), D2a (Animal), D2b (Metallic Balloon), D2c (Other), D2d (Vegetation), and D2f (Weather).

The At-Risk Worker Safety Outreach provides mailers, flyers and other outreach to third-party contractors, agricultural customers, first responders, and others to inform of the dangers of working around energized equipment, especially overhead conductor. Effectiveness of these efforts are reviewed periodically through analysis of retention rates, recall, open/read rates, and other measures of public awareness.

1. Drivers Impacted

Public Outreach would be expected to reduce the frequency of public contact with intact conductor. Given the differences between the two bowties (see Figure II-1) and the RAMP model structure, SCE chose to represent Public Outreach as not impacting any drivers. See the Outcomes and Consequences section below for additional details.

2. Outcomes and Consequences Impacted

SCE models Public Outreach as reducing the safety consequences associated with Outcome O1 (Energized Wire-Down) in the top bowtie. This is based on the assumption that energized wire-down would be less likely to result in serious injury or fatality consequences through proactive messaging, education, and awareness for how to work around, respond to, and avoid contact with energized conductor.

SCE models Public Outreach as also reducing the safety consequences of Outcome O3 (Intact Energized Wire Contact) in the bottom bowtie. This was intended to mimic the equivalent risk reduction that would expected from a reduction in frequency of third party contact with intact lines.

IV. Mitigations

In addition to compliance and control activities mentioned above, SCE has identified potential new and innovative ways to mitigate this risk, to further reduce the frequency and/or impact of the risk event. All of these activities are summarized in Table IV-1, and discussed in more detail thereafter.

Table IV-1 – Inventory of Mitigations[33]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Proposed	Alt. #1	Alt. #2
M1	Overhead Conductor Program (OCP) Utilizing Covered Conductor	D1a-b, D2a-d,f	O1	S-I, S-F		X	
M2	Comprehensive Branch Line Fusing	D1b, D2a,c,d,f	-	-		X	X
M3	Targeted Underground Conversion	D1,D2,D3,D4	-	-			X
M4	Infrared Inspections	D1a	-	-	X	X	X
M5	Wildfire Covered Conductor Program	D1a-b, D2a-d,f	O1	S-I, S-F	X	X	X

Consequence Abbreviation: Serious Injury - S-I; Fatality - S-F; Reliability - R; Financial - F

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk, and which may continue through the RAMP period. Mitigations are modeled in this report..

A. M1 - OCP Using Covered Conductor

1. Description

This mitigation is specific to SCE's non-HFRA and is an alternative to the combination of C1 (OCP) and C1a (OCP utilizing targeted covered conductor). As previously described, C1 represents 100% of the planned OCP expenditures in 2018-2020 and 90% of the planned OCP expenditures in 2021-2023 using bare conductor, and C1a represents the remaining 10% of the OCP expenditures in 2021-2023 using covered conductor. In this mitigation alternative, M1 assumes that 100% of the planned OCP expenditures in years 2018-2023 would entirely use covered conductor instead of bare conductor.

2. Drivers Impacted

M1 impacts the same drivers addressed by the OCP (C1), namely D1 (Equipment Caused) and D2 (Equipment / Facility Contact).[34] However, the OCP using Covered Conductor

[33] Please refer to WP Ch. 5, pp. 5.3 – 5.11 *(Control & Mitigation Risk Reduction Effectiveness)* and WP Ch. 5, pp. 5.12 – 5.22 *(Mitigation Effectiveness Workpaper).*

[34] Specifically, M1 affects the following sub-drivers: D1a (Connector / Splice / Wire), D1b (Other), D2a (Animal), D2b (Metallic Balloon), D2c (Other), D2d (Vegetation), and D2f (Weather).

assumes different mitigation effectiveness for specific drivers than the OCP. The most significant difference is that the OCP using Covered Conductor assumes much higher mitigation effectiveness for animal, metallic balloon, and vegetation-related drivers (D2a, D2b, and D2d respectively).[35]

3. Outcomes and Consequences Impacted

Contact with covered conductor is less likely to result in serious injury or fatality than contact with bare conductor in an energized wire-down event. Therefore, this mitigation was modeled as reducing the safety consequences associated with outcome O1 (energized wire-down).

Contact with covered conductor is also less likely to result in serious injury or fatality than contact with bare conductor in an event involving contact with intact overhead conductor (outcome O3). However, since O3 is such a small percentage of all of the modeled outcomes, SCE concluded that this effect would be negligible in the overall risk analysis. Therefore, as a simplifying assumption, SCE did not model any impact on the safety consequences associated with outcome O3.

B. M2 - Comprehensive Branch Line Fusing

1. Description

Comprehensive Branch Line Fusing is a short-term program that would target all unfused branch, or tap, lines in SCE's non-HFRA. Branch Line Fuses are protective devices that are designed to clear faults on the system limiting the number of customers impacted by the fault. With the addition of new Branch Line Fuses, faults can clear faster, and the energy associated with faults will be reduced as a result. This reduced energy results in less damage to overhead wire and decreased probability of conductor failure and wire-down.

This is a conceptual mitigation, and at this time SCE does not know exactly how many Branch Line Fuses would be installed throughout the system under such a program. For modeling purposes, SCE assumed that approximately 15,000 new Branch Line Fuses would be installed in the non-HFRA of the SCE system through 2023 as part of this mitigation. For a discussion of fusing mitigations within HFRA, please see the Wildfire Chapter.

[35] Please refer to WP Ch. 5, pp. 5.3 – 5.11 *(Control & Mitigation Risk Reduction Effectiveness)*.

2. Drivers Impacted

Comprehensive Branch Line Fusing impacts the triggering event frequency associated with drivers D1 (Equipment Cause), and D2 (Equipment / Facility Contact).[36]

Comprehensive Branch Line Fusing would reduce fault energy associated with system faults, and thereby reduce the frequency of wire-down events caused by fault-related drivers. The concept of fault energy can be described as the electric system's natural reaction to fault conditions. Dominant factors for fault energy are the time duration and the magnitude of electrical current during a fault. Branch Line Fusing decreases the time duration of faults, and therefore decreases the fault energy. This helps reduce the probability of equipment damage and wire-down due to faults.

3. Outcomes and Consequences Impacted

Comprehensive Branch Line Fusing will not impact outcomes or consequences in the risk model.

C. M3 – Targeted Underground Conversion

1. Description

This mitigation is specific to SCE's non-HFRA and is an alternative to C1a (OCP utilizing targeted covered conductor). Targeted Underground Conversion would involve the conversion of portions of existing overhead circuits or lines to underground circuits or lines. While C1a assumed that 10% of the OCP expenditures would use covered conductor, M3 assumes that 10% of the OCP expenditures would be used for targeted underground conversion.

An overhead to underground conversion involves removing all aboveground equipment, such as poles, conductor, transformers, switches, etc., and then installing underground conduit, cable, vaults, manholes, transformers, switches, etc. Undergrounding electric facilities can also be challenging and may require multiple designs based on specific geographic factors. This amount of work and challenges make undergrounding a relatively high cost mitigation.

In the scope of this risk analysis as previously described, targeted underground conversion would address more overhead risks than covered conductor.[37] However, targeted

[36] Specifically, M2 affects the following sub-drivers: D1b (Other), D2a (Animal), D2c (Other), D2d (Vegetation), and D2f (Weather).

[37] The scope of this risk analysis was defined in terms of overhead assets only. Covered conductor is an overhead asset; underground conversion eliminates overhead assets and replaces them with underground assets. The inherent risks associated with underground assets were not included in this analysis.

underground conversion would also be significantly more expensive than covered conductor. SCE modeled M3 as a mitigation alternative to C1a to evaluate whether the additional benefits of underground conversion would be large enough to justify the additional costs. For comparison purposes, M3 would addressing approximately 4.6 miles per year at the same annual cost that C1a would use to address approximately 27 circuit miles per year.

SCE currently converts overhead lines to underground in compliance with Tariff Rules 20A, 20B, and 20C.[38] In cities where undergrounding is required, SCE will install all new construction in compliance with the city's requirements. This would be a new mitigation for SCE because there are currently no programs which specifically target converting overhead to underground lines to address contact with energized equipment risks.

2. Drivers Impacted

Underground conversion was modeled as addressing all overhead drivers in this risk statement. This is based on a key underlying assumption – that the drivers considered in this chapter are by definition overhead drivers only. New risks would be introduced into the system with underground conversion. For example, people who are digging near underground electrical assets may expose themselves to "dig-in" risks of contact with energized underground cable. The new risks that would be introduced with underground conversion were not modeled in this analysis.

3. Outcomes and Consequences Impacted

Targeted Underground Conversion will not impact outcomes or consequences in the risk model.

D. M4 - Infrared Inspections

1. Description

Infrared (IR) Inspections for overhead distribution lines identify "Hot Spots" on distribution system equipment. Examples of equipment that will be included in these inspections are splices, connectors, switches, and transformers. Hot Spots are areas with temperature differences between either two phases, or two pieces of metal on one phase. Hot Spots are reliable predictors of future component failures that, if unaddressed, might lead to equipment failures. These Hot Spots are not visible to the naked eye and can only be detected by a trained thermographer using an IR camera.

[38] *See* Rule 20 Replacement of Overhead with Underground Electric Facilities *available at* https://www.sce.com/NR/sc3/tm2/pdf/Rule20.pdf.

This technology can be used proactively, in routine inspections, and assessments of facilities after a failure occurs to identify other potential conditions that may exist to further aid in preventing repeated circuit interruptions.

When infrared inspections identify problems that need to be mitigated, these problems would be addressed through SCE's Preventive Maintenance program (as previously described in CM3 above).

2. Drivers Impacted

Infrared inspections would only address Sub-Driver D1a (Connector / Splice / Wire). Infrared inspections are designed to be effective at identifying connectors, splices, wire, and other equipment that show signs of thermal fatigue. Infrared inspections are generally not effective at identifying other types of equipment failures or contact-related faults.

3. Outcomes and Consequences Impacted

Infrared Inspections will not impact outcomes or consequences in the risk model.

E. M5 – Wildfire Covered Conductor Program (WCCP)

1. Description

This mitigation represents the circuit miles in SCE's HFRA that SCE will target for reconductoring with covered conductor as a wildfire risk mitigation. WCCP identifies scope in three main categories: (1) spans with vintage small conductor at risk of damage during fault conditions, (2) spans with elevated risks of vegetation-related CFO faults, and (3) spans with elevated risks of non-vegetation-related CFO faults.

For purposes of the analysis described in this Chapter, SCE is only modeling this mitigation's impact on risks associated with Contact with Energized Equipment. The impact on risks associated with wildfire and WCCP details are described in the Wildfire Chapter.

2. Drivers Impacted

The WCCP (M5) impacts the same drivers addressed by the OCP (C1), namely: D1 (Equipment Cause), and D2 (Equipment/Facility Contact).[39] However, the WCCP assumes different mitigation effectiveness for specific drivers than the OCP. The most significant difference is that the WCCP assumes much higher mitigation effectiveness for animal, metallic balloon, and vegetation-related drivers (D2a, D2b, and D2d respectively).

[39] Specifically, C1a affects the following sub-drivers: D1a (Connector / Splice / Wire), D1b (Other), D2a (Animal), D2b (Metallic Balloon), D2c (Other), D2d (Vegetation), and D2f (Weather).

3. Outcomes and Consequences Impacted

Contact with covered conductor is less likely to result in serious injury or fatality than contact with bare conductor in an energized wire-down event. Therefore, this mitigation was modeled as reducing the safety consequences associated with Outcome O1 (energized wire-down).

Contact with covered conductor is also less likely to result in serious injury or fatality than contact with bare conductor in an event involving Outcome O3 (Intact Energized Wire Contact). However, since O3 is such a small percentage of all of the modeled outcomes, SCE concluded that this effect would be negligible in the overall risk analysis. Therefore, as a simplifying assumption, SCE did not model any impact on the safety consequences associated with Outcome O3.

F. Advanced Wire-Down Detection

4. Description

In addition to the controls and mitigations listed above, SCE is working to develop advanced techniques to detect and clear high impedance faults, thereby reducing the probability that wire-down events will remain energized. Because the consequences of Outcome O1 (Energized Wire-Down) are much larger than the consequences of Outcome O2 (De-Energized Wire-Down), risk associated with contact with overhead conductor would be reduced with improvements in detecting wire-down. In the risk statement above, such mitigations would decrease the relative percentage of O1 and increase the relative percentage of O2.

The first technique under consideration is using meter data to detect wire-down events. This effort would apply an automated, rule-based detection algorithm to interval voltage data from SCE's meters to identify and alarm for observed low-voltage events in near real-time that could be indicative of wire-down events. A semi-automated version of this system, which automatically collects data but does not automatically take action based on that data, has been implemented by SCE as an initial demonstration project in 2018. Lessons learned from this demonstration project are being analyzed for future full-scale deployment.

The second technique under consideration is using high impedance fault detection modules within feeder protective relays. Protective relay manufacturers have been working to develop modules within feeder relays that have advanced algorithms to recognize the voltage or current signatures of high impedance faults, such as those that can occur with a wire-down feeder event. SCE previously installed relays with such modules on selected distribution feeders in 2016. At the time, these relays were configured to alarm – but not trip – for fault events that the relay algorithms determined to be possible wire-down events. Since 2016, numerous

"nuisance alarms" (i.e., alarms without any corresponding wire-down event) have been identified. SCE has been working with relay manufacturers and other utilities to address this problem for future implementation.

The third technique under consideration is using Spread Spectrum Time-Domain Reflectometry (SSTDR) to detect wire-down events. This is a detection system that injects a high-frequency signal on the distribution circuit at a known starting point, and measures the returning signal reflections. These reflections are compared to a known "healthy" circuit profile and the location of anomalies – potentially indicative of high impedance faults – are reported by the system. SCE has very recently completed SSTDR prototype testing. We currently anticipate initiating an SSTDR field pilot in early 2019.

These mitigations were not modeled as part of this RAMP report, because the underlying techniques are not sufficiently mature at this time.

V. Proposed Plan

SCE has evaluated each control and mitigation listed in Section III and has developed a Proposed Plan, as shown in Table V-1.

Table V-1 – Proposed Plan (2018-2023 Totals)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Overhead Conductor Program (OCP)	2018	2023	$ 715	$ -	3.22	0.0045	3.37	0.0047
C1a	Overhead Conductor Program (OCP) Utilizing Targeted Covered Conductor	2021	2023	$ 34	$ -	0.10	0.0029	0.10	0.0030
C2	Public Outreach	2018	2023	$ -	$ 33	0.42	0.0130	0.46	0.0140
M4	Infrared Inspections	2018	2023	$ -	$ 3	1.04	0.3627	1.09	0.3797
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.54	0.0005	0.55	0.0005
			Total - Proposed Plan	**$1,910**	**$36**	**5.32**	**0.0027**	**5.57**	**0.0029**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

A. Overview

The Proposed Plan includes the existing OCP at specified levels over the RAMP period. In this plan, the majority of OCP projects will be constructed with bare overhead conductor (C1), and a minority of projects will use covered conductor (C1a).

The Proposed Plan also includes Public Outreach (C2). This effort will focus on educating and informing the general public on what actions to take and to avoid when encountering a downed electrical wire. Our efforts here will also aim to inform at-risk workers such as third-party contractors, agricultural customers, and first responders regarding the dangers of working around energized equipment and downed wires. Additionally, the Proposed Plan includes infrared inspections of overhead equipment and connectors (M4) to identify problems and mitigate them before they result in faults and wire-down events.

The Proposed Plan also includes a specific mitigation identified in the Wildfire chapter (M5). This mitigation involves installing covered conductor within SCE's high fire risk area. While this mitigations is designed to address risks associated with wildfire, it is expected to provide *additional* risk reduction benefits related to contact with energized overhead conductor as well.

B. Execution feasibility

Executing the bare conductor OCP component (C1) is feasible as it relies on highly mature work processes, well-understood equipment types, and established work methods. SCE has a high degree of confidence in its ability to target, execute, and derive benefit from the OCP program when built with bare conductor.

Regarding the covered conductor OCP component (C1a), SCE anticipates that the lessons learned from deploying the Wildfire Covered Conductor Program in HFRA (M5) – including the associated construction and design standards, material specifications, work methods, and so on – will make targeted covered conductor installation as feasible to execute as bare conductor.

Executing public outreach (C2) is feasible, since it reflects continued execution of a control activity currently in place today.

The execution of the infrared inspections mitigation (M4) is feasible as this mitigation measure has already been successfully piloted and is being implemented today. For example, in years 2016 and 2017, SCE piloted the successful scan of approximately 11,200 overhead circuit miles in the service territory. In 2018, SCE has been working to scan all of the remaining overhead circuit miles not included in previous years. By year end 2018, SCE will have successfully demonstrated its ability to systematically scan the entirety of its overhead distribution system.

The execution feasibility of the Wildfire Covered Conductor Program (M5) is discussed in detail in the Wildfire chapter.

C. Affordability

The results shown in Table I-2 indicate that, at the plan level, the RSEs of the Proposed Plan and the two alternative plans are comparable. However, to understand the underlying cost-effectiveness differences of the proposed plan relative to the alternative plans, the RSEs of individual controls and mitigations as shown in Table II-7 need to be examined.

1. Conductor (C1 and C1a)

The Proposed Plan involves the existing OCP with a majority of bare conductor (i.e., C1) and a targeted minority of covered conductor (i.e., C1a). This is fundamentally different than Alternative Plan #1, which assumes existing OCP with entirely covered conductor. This is also fundamentally different than Alternative Plan #2, which assumes a targeted minority of underground conversion (M3) instead of covered conductor.

Therefore, the alternative plans reflect two theoretical “enhancements” to the Proposed Plan: (1) In Alternative Plan #1, we deploy 100% instead of 10% of covered conductor

expenditures; and (2) In Alternative Plan #2, we deploy 10% underground conversion instead of 10% covered conductor expenditures.

When we look at the collective RSEs of conductor-related controls and mitigations – i.e., C1 and C1a (Proposed Plan) versus M1 (Alternative Plan #1) versus C1 and M3 (Alternative Plan #2), the Proposed Plan reduces the most risk, addresses the most circuit miles, and has the most spend-efficient conductor mitigation combination all at the same time. These comparative details are shown in Table V-2 below.

Table V-2 – Comparison of Conductor-Related Mitigation Options

	Cost ($M)	MRR	RSE	Miles Addressed
C1 and C1a *(OCP + Targeted Covered Conductor)* *(Proposed Plan)*	749.5	3.32	4.430E-03	2,045 circuit miles
M1 *(OCP using Covered Conductor)* *(Alternative Plan #1)*	749.5	3.25	4.336E-03	1,749 circuit miles
C1 and M3 *(OCP + Underground Conversion)* *(Alternative Plan #2)*	790.1	3.31	4.189E-03	1,992 circuit miles

2. Public Outreach (C2) and Infrared Inspections (M4)

Public Outreach (C2) and Infrared Inspections (M4) are included in all three mitigation plans. Public Outreach is the one mitigation that directly addresses the human element of contact with overhead conductor, by helping to educate the public about the potential hazards of coming into contact with energized power lines. Infrared Inspections enable SCE to target degraded connectors, splices, and attachments nearing the end of their life. Both of these activities – M4 in particular – are relatively low-cost and high-RSE activities based on the modeling results.

3. Wildfire Covered Conductor Program (M5)

SCE has included the WCCP in the proposed and alternative plans for this chapter because they are in the Proposed Plan of the Wildfire chapter. As highlighted above, the WCCP is designed to address risks associated with wildfire, but it is also expected to provide additional risk reduction benefits related to contact with overhead conductor risks as well. Therefore, this mitigation is included in the Proposed Plan shown above.

Wildfire risk benefits of M5 were specifically excluded in this chapter, just as contact-with-overhead conductor risk benefits of M5 were excluded in the Wildfire chapter. This helps ensure that M5 benefits were not double-counted. However, SCE did include full M5 costs in the RSE calculations in both chapters, because SCE does not have a methodology for accurately dividing the cost of any program that provides benefits across multiple independent risk statements. In essence, RSE calculations for M5 assumed only *some* of the expected *benefits* (i.e., benefits specific to each chapter) but *all* of the expected *costs* (i.e., the full program cost in both chapters). The net effect of this is that calculated RSEs for the WCCP were understated in each of these two chapters.

D. Other Constraints

The Proposed Plan assumes that SCE will be able to identify OCP-candidate circuits that are most appropriate for covered-conductor targeting (C1a). SCE does not presently have scoping tenets that clearly define which non-high fire risk area circuits are most appropriate for covered conductor versus bare conductor when building OCP projects. SCE anticipates that the appropriate places for implementing covered conductor as part of OCP are locations with a combination of small-wire exposure and a clear history of repeated exposure to contact from object faults such as balloons, animals, and vegetation. SCE expects that the lessons learned from covered conductor in high fire risk areas (i.e., M5) will help inform the scoping tenets for targeted implementation of covered conductor in non-high fire risk areas (i.e., C1a).

VI. Alternative Plan #1

SCE evaluated other options to address this risk and developed an Alternative Plan #1, as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018-2023 Totals)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C2	Public Outreach	2018	2023	$ -	$ 33	0.42	0.0129	0.46	0.0139
M1	Overhead Conductor Program (OCP) Utilizing Covered Conductor	2018	2023	$ 750	$ -	3.25	0.0043	3.36	0.0045
M2	Comprehensive Branch Line Fusing	2018	2023	$ 83	$ -	0.29	0.0035	0.31	0.0037
M4	Infrared Inspections	2018	2023	$ -	$ 3	1.09	0.3798	1.14	0.3973
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.54	0.0005	0.55	0.0005
			Total - Alternative #1	**$1,994**	**$36**	**5.59**	**0.0028**	**5.81**	**0.0029**

A. Overview

There are two primary differences between Alternative Plan #1 and the Proposed Plan. First, Alternative Plan #1 assumes that all OCP projects will be constructed with covered conductor (M1) instead of a combination of bare conductor (C1) and targeted covered conductor (C1a). This alternative was selected to compare the risk mitigation benefits of an entirely-covered conductor standard for OCP against the primarily bare conductor standard for OCP that is currently in place today.

Second, Alternative Plan #1 implements Comprehensive Branch Line Fusing (M2), while the Proposed Plan does not. This was done to compare the differences between an accelerated Branch Line Fusing deployment strategy and the current Branch Line Fusing strategy achieved through the OCP. All other controls and mitigations are consistent between Alternative Plan #1 and the Proposed Plan.

B. Execution feasibility

Alternative Plan #1 is technically feasible to execute. We anticipate learning from the deployment of covered conductor in HFRA (M5) to help facilitate the deployment of M1. These lessons learned from deploying covered conductor in HFRA (M5), may involve the associated construction and design standards, material specifications, work methods, etc.

Alternative Plan #1 may not be feasible to implement from a process perspective. For purposes of this RAMP report, we model M1 as if it were deployed in 2018. However, we expect that lead times due to engineering, design, and material procurement would delay that deployment.

Regarding executing a comprehensive Branch Line Fusing program (M2), SCE has not previously implemented such a fuse installation program at this scale and pace. However, SCE has extensive experience installing BLFs at individual locations throughout its service territory. Executing such a program is assumed to be feasible as it would rely on highly mature work processes, well-understood equipment types, and established work methods.

For all other controls and mitigations, please see the execution feasibility discussion in the Proposed Plan section above.

C. Affordability

The results shown in Table I-2 indicate that, at the plan level, the RSEs of the Proposed Plan and the two alternative plans are comparable. Below, we discuss the RSE differences between the Proposed Plan and Alternative Plan #1 in two areas: conductor and comprehensive branch line fusing.

1. Conductor (M1)

In terms of conductor-related mitigation options, Table V-2 above shows that Alternative Plan #1 reduces less risk, addresses less circuit miles, and is less spend-efficient than the Proposed Plan. These results indicate that fully deploying covered conductor as part of the OCP is not justified by risk analysis at this time.

2. Branch Line Fusing Mitigation (M2)

Alternative Plan #1 includes comprehensive Branch Line Fusing (M2) as a mitigation, whereas the Proposed Plan does not. The modeling results suggest that comprehensive Branch Line Fusing has a slightly lower RSE than the covered conductor mitigation modeled in M1.

SCE notes that short-term system-wide application of any mitigation – such as comprehensive Branch Line Fusing (M2) – will have a lower equivalent RSE than a more focused and targeted application on assets that represent the greatest risk at the present time. A short-term, comprehensive program would still be appropriate in situations where the residual risk after targeted benefit is not acceptable.

In this case, the modeling indicates that comprehensive Branch Line Fusing (M2), while efficient from a spending perspective, would reduce a relatively small amount of total risk. Specifically, the application of M2 would reduce the total baseline risk by approximately 1% in MARS units. While this mitigation is not in the Proposed Plan, SCE will continue to deploy branch line fuses within the OCP program, and will evaluate additional opportunities for targeted deployment.

D. Other Considerations

SCE is not aware of other issues associated with Alternative Plan #1.

VII. Alternative Plan #2

SCE evaluated other options to address this risk, and developed an Alternative Plan as shown in Table VII-1.

Table VII-1 – Alternative Plan 2 (2018-2023 Totals)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Overhead Conductor Program (OCP)	2018	2023	$ 715	$ -	3.19	0.0045	3.34	0.0047
C2	Public Outreach	2018	2023	$ -	$ 33	0.43	0.0130	0.46	0.0140
M2	Comprehensive Branch Line Fusing	2018	2023	$ 83	$ -	0.29	0.0035	0.30	0.0036
M3	Targeted Underground Conversion	2021	2023	$ 75	$ -	0.12	0.0017	0.13	0.0017
M4	Infrared Inspections	2018	2023	$ -	$ 3	1.03	0.3606	1.08	0.3771
M5	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	0.54	0.0005	0.54	0.0005
			Total - Alternative #2	**$2,034**	**$36**	**5.60**	**0.0027**	**5.86**	**0.0028**

A. Overview

There are two primary differences between Alternative Plan #2 and the Proposed Plan. Alternative Plan #2 assumes that the majority of OCP projects will be constructed with bare overhead conductor (C1), and a targeted minority of projects will use full underground conversion (M3) instead of targeted covered conductor. This alternative was selected to compare the differences between covered conductor and underground conversion for risk mitigation benefits.

Alternative Plan #2 also assumes the implementation of a comprehensive branch line fusing program (M2), while the Proposed Plan does not. This mitigation was selected to compare the differences between an accelerated fusing strategy and the current fusing strategy achieved through the OCP.

All other controls and mitigations are consistent between this alternative and the Proposed Mitigation Plan.

B. Execution feasibility

Alternative Plan #2 is feasible to execute for a variety of reasons. With respect to executing the targeted underground conversion OCP component (M3), SCE notes that the modeling of M3 has resulted in a relatively small number of circuit miles that would actually be converted to underground on an annual basis. SCE anticipates that the lessons learned from underground conversion projects under Rule 20 would make covered conductor installation feasible to execute. However, SCE also notes that M3 would be subject to additional delays associated

with the greater complexities that can take place when constructing underground conversion projects.

For all other controls and mitigations included in this plan, please refer to the discussion above in the execution feasibility sections of the Proposed Plan and Alternative Plan #1.

C. Affordability

The results shown in Table I-2 indicate that, at the plan level, the RSEs of the Proposed Plan and the two alternative plans are comparable. Below, we discuss the RSE differences between the Proposed Plan and Alternative Plan #2 in two areas: conductor and comprehensive branch line fusing.

1. Conductor (C1 and M3)

In terms of conductor-related mitigation options, Table V-2 above shows that Alternative Plan #2 reduces less risk, addresses less circuit miles, and is less spend-efficient than the Proposed Plan. These results indicate that underground conversion as part of the OCP is not justified by risk analysis at this time.

2. Branch Line Fusing Mitigation (M2)

For discussion of the comprehensive branch line fusing mitigation (M2), please see the discussion in Alternative Plan #1 above.

D. Other Considerations

SCE is not aware of other issues associated with Alternative Plan #2.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

SCE has learned some important lessons through this RAMP process in terms of interdependence assumptions in modeling the effectiveness of individual mitigations, degrees of confidence in modeling mitigation effectiveness, and similarity between scope and cost in mitigation portfolios.

1. Interdependence Assumptions in Mitigation Effectiveness Modeling

One of the challenges SCE faced in this RAMP chapter is that modeling mitigation effectiveness is much more challenging in a comprehensive mitigation portfolio than it is for individual mitigations. While this topic is especially relevant to this chapter, it also affects other RAMP chapters as well. Accordingly, we explain this lesson learned in greater detail in Chapter II – Risk Model Overview.

2. Degrees of Confidence in Mitigation Effectiveness Modeling

There can be a wide variety of degrees of confidence in modeling mitigation effectiveness. While the RAMP methodology does simulate risk uncertainty (through probabilistic analysis of consequence distributions), it does not, at present, have a way to describe underlying uncertainty in modeling mitigation effectiveness. While this topic is especially relevant to this chapter, it also affects other RAMP chapters as well. Accordingly, we explain this lessons learned in greater detail in Chapter II – Risk Model Overview.

3. Similarity between Scope and Cost in Mitigation Portfolios

Finally, SCE learned the importance of developing mitigation portfolios where there is a wide enough variation between scope and cost in the various mitigation portfolios. In this case, SCE used a cost-based approach to define portfolios. In other words, SCE held the OCP expenditures constant among all three portfolios (i.e., the dollars spent), and varied the amount of scope that could be constructed within that expenditures. This resulted in relatively small variations in benefits, and therefore very similar RSE results among the portfolios. To take just one example, the similarity between the 10% cost representation of C1a (covered conductor) in the Proposed Mitigation Plan and the 10% cost representation of M3 (targeted underground conversion) in Alternative Plan #2 made it very difficult to see variety in the modeling results.

In retrospect, greater clarity of the actual RSE differences would have been achieved had SCE modeled a wider range of scope and cost in the mitigation portfolios.

B. Data Collection & Availability

One of the biggest challenges that SCE faced in this RAMP modeling effort was understanding the distribution of outcomes between Energized Wire-Down (O1) and De-Energized Wire-Down (O2). In SCE's Wire-Down Database, approximately half of the wire-down events are listed as either "unknown" or "blank" with respect to whether the conductor was energized on the ground. SCE attributes this to the fact that the Wire-Down Database is populated by personnel who arrive on the scene sometime after the wire-down event takes place. Typically, there is limited information at their disposal to understand the precise sequence of events and determine definitively whether the wire on the ground was energized or not at the time of the event. This was a challenge for RAMP modeling purposes.

SCE modeled the distribution of outcomes O1 and O2 based on assuming that the unknowns represent a mix of both energized and de-energized wire-down events. Going forward, SCE anticipates that continued development of more advanced high impedance fault detection techniques will help bridge this gap and further refine the actual distribution of outcomes O1 and O2 in the system. For additional details, see the "Advanced Wire-Down Detection" discussion in the Mitigations section above.

C. Performance Metrics

SCE has identified three performance metrics that are attributable to this risk including:

- Number of CPUC-reportable safety incidents associated with overhead conductor.
- Number of wire-down events.
- Outage minutes due to wire-down events.

Additionally, SCE has identified useful metrics to track effectiveness in executing programs. These metrics involve tracking the number of deployed unit counts versus planned unit counts related to our overhead conductor, including:

- Circuit miles of OCP projects constructed.
- Number of Branch Line Fuses installed as part of OCP.
- Circuit miles of covered conductor installed.

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Risk Assessment and Mitigation Phase

Cyberattack

Chapter 6

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

In this chapter, we evaluate the risk to SCE, our electric system, and the customers and communities we serve if a cyberattack compromises SCE system controls. SCE identified and quantified the potential safety, reliability, and financial consequences resulting from this risk.

SCE's bowtie structure for this cyberattack risk has identified several options to mitigate the risk. We present a Proposed Plan that balances risk mitigation, execution feasibility, and cost efficiency. SCE's proposed portfolio of mitigations leverages the success of existing and ongoing cybersecurity programs, and adds enhanced capabilities that will help maintain our defenses amidst the growing and persistent threat of cyberattack.

Cybersecurity presents an ever-evolving challenge to SCE. The threat of cyberattacks is growing; attacks are continually becoming more frequent and more sophisticated. Our grid is evolving and incorporating communicating and operating technology that enable us to respond faster, operate our system more efficiently and reliably, and incorporate distributed energy resources at a greater level. But more reliance on advanced technology to operate and communicate necessarily increases risk of cyberattack, and greater potential consequences if a cyberattack is successful. State and federal government agencies are increasingly supporting cybersecurity. That support springs from the growth in cyberattack risks. SCE will need to increase its capabilities to address this.

B. Scope

The scope of this chapter is defined in Table I-1 below.

Table I-1 - Chapter Scope	
In Scope	• Unauthorized access to SCE's system controls, including our Supervisory Control and Data Acquisition (SCADA) network, industrial control systems (ICS), and other systems that access and utilize Critical Energy/Electric Infrastructure Information (CEII).[1]
Out of Scope	• Risks associated with protecting non-grid related cybersecurity concerns, such as Personally Identifiable Information (PII), operations related to billing and payment, customer care, etc. These are out of scope because the probable and direct safety consequences range from zero to very little. However, if such non-grid related cybersecurity areas can be utilized as a pathway to our grid network, then we address these areas as appropriate in this chapter.[2] • Secondary, indirect safety risks associated with cyberattacks.[3]

C. Summary Results

Table I-2 summarizes this chapter's baseline risk analysis, controls and mitigations contemplated, and portfolio results over the 2018 – 2023 period.

[1] These are the systems that operate the electric system today, from central-station power plants, to our transmission and distribution power systems, and reaching through to the interconnection of utility-scale and localized, distributed energy resources.
[2] While not the focus of this RAMP chapter, SCE maintains robust data controls to protect the privacy of our five million customers, and secure the vendor data in our possession.
[3] For example, the potential secondary safety impacts that result if our control systems are comprised and the end result is a persistent blackout. SCE believes this is a viable and adversary-desired outcome that could potentially lead to significant safety and financial consequences. However, at this time, the modeling of such a scenario involves developing considerable assumptions and a virtual cascade of hypothetical events, and is out of scope for this immediate RAMP analysis.

Table I-2 – Summary Results – 2018-2023 Annual Averages

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1a	Perimeter Defense	x		
C1b	Perimeter Defense		x	
C1c	Perimeter Defense			x
C2a	Interior Defense	x		
C2b	Interior Defense		x	
C2c	Interior Defense			x
C3a	Data Protection	x		
C3b	Data Protection		x	
C3c	Data Protection			x
C4a	SCADA Cybersecurity	x		
C4b	SCADA Cybersecurity		x	
C4c	SCADA Cybersecurity			x
C5a	Grid Modernization Cybersecurity	x		
C5b	Grid Modernization Cybersecurity		x	
C5c	Grid Modernization Cybersecurity			x
M1	Accelerated Hardware Refresh			x
Mean (MARS)	*Cost Forecast ($ Million)*	$80	$77	$92
	Baseline Risk	1.78	1.78	1.78
	Risk Reduction (MRR)	0.72	0.37	0.99
	Remaining Risk	1.06	1.42	0.79
	Risk Spend Efficiency (RSE)	0.009	0.005	0.011
Tail Average (MARS)	*Cost Forecast ($ Million)*	$80	$77	$92
	Baseline Risk	11.02	11.02	11.02
	Risk Reduction (MRR)	4.56	2.29	6.34
	Remaining Risk	6.47	8.74	4.68
	Risk Spend Efficiency (RSE)	0.057	0.030	0.069

CM: Compliance (Not shown in this chart, but addressed in Section III; this is an activity required by law, regulation, etc. As discussed in Chapter I - RAMP Overview, SCE does not model compliance activities in this report, and as such, excludes these activities from this table.)

C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE does model controls in this report.)

M: Mitigation (Activity commencing in 2018 or later to affect this risk. SCE does model mitigations in this report.)

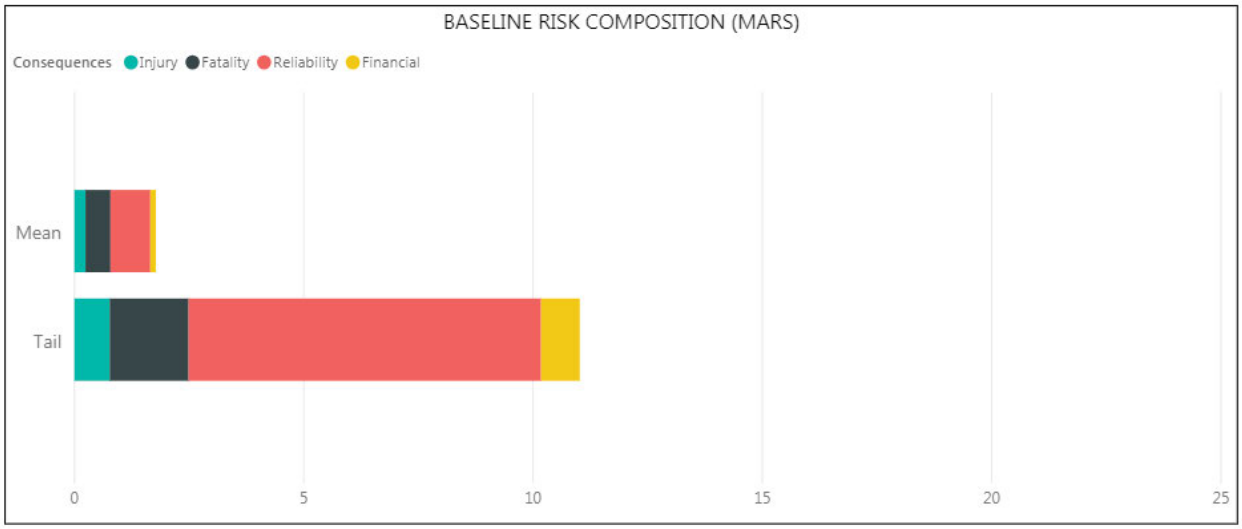
MARS: Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk consequences from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR: Mitigation Risk Reduction. This is the reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE: Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 maps the consequences inherent in the baseline risk. The majority of this risk is composed of reliability impacts.

Figure I-1 – Baseline Risk Composition (MARS)



MARS CONSEQUENCE

AggregationType	Injury	Fatality	Reliability	Financial	**Total**
Mean	0.24	0.55	0.87	0.12	**1.78**
Tail	0.77	1.72	7.69	0.84	**11.02**

Maximum MARS is 100

D. Sensitive, Confidential Information Must Be Protected

The RAMP process required that SCE perform detailed and confidential[4] internal evaluations of our computing and operating systems, cybersecurity tools, and areas of vulnerability. This was a very valuable process, and SCE appreciates the opportunity to critically evaluate our cybersecurity program as it continually evolves. The detailed analysis that we performed internally around cybersecurity has informed the discussion we present in this chapter. However, SCE must necessarily safeguard this critical information. SCE's cybersecurity efforts include protecting the electric grid, which has been designated by the Department of Homeland

[4] These evaluations required analyzing specific details concerning how various cyber defenses (such as software tools) perform in addressing different threats. Disclosing this information could potentially help an attacker gain crucial information about how SCE protects its systems, and where gaps might exist.

Security (DHS) as critical infrastructure.[5] Therefore, a secure process for disclosing detailed tactics, techniques, and procedures to stakeholders to this proceeding is needed to help ensure its protection.

To help the Commission access the information necessary to answer specific questions regarding the cybersecurity risks, mitigations, and cost forecasts, SCE can provide an in-person briefing to share additional detail not found in this Report.

[5] DHS identifies 16 critical infrastructure sectors whose assets, systems, and networks, whether physical or virtual, are considered so vital to the United States that their incapacitation or destruction would have a debilitating effect on security, national economic security, national public health or safety, or any combination thereof. The U.S. Energy Sector is defined as one of these Critical Infrastructure sectors. This information is *available at* https://www.dhs.gov/critical-infrastructure-sectors

II. Risk Assessment

A. Background

1. Increased Threat of Cyberattack

The energy sector is under continuous cyberattack.[6] The attack methods, strategies, and capabilities are constantly evolving as new types of attacks are discovered and carried out. Intrusion attempts against SCE continue to increase. Such attacks include computer viruses, worms, phishing, spyware, and advanced persistent threats. Any of these aggressive actions, if successful, could significantly damage SCE's information systems. A prominent security-related periodical has noted: "The modern enterprise network has become expansive, porous, and completely blurred due to the large number of Internet-facing applications that have been deployed and adopted. The number of potential entry points into the enterprise network has proliferated uncontrollably."[7]

Cybersecurity's importance to utilities has expanded as systems and data have become more integral to business operations, and as the electric infrastructure has become more essential to national commerce and communications capabilities. Cyberattacks are continually growing in number and sophistication, and the availability of cyber weapons[8] is on the rise as well. Therefore, maintaining a strong defense against cyberattack requires a continually evolving set of strategies.

2. Real-Life Examples of Costly Cyberattacks

Recent examples of cyberattacks are well-documented in the news media and the intelligence community. These include but are not limited to:

- The disruption of Ukraine's power grid by Russian cyber actors[9] in December 2015, causing over 225,000 customers to lose power.[10]
- The Federal Bureau of Investigation (FBI) and U.S. Department of Homeland Security (DHS) have identified that since at least March 2016, Russian government cyber actors targeted U.S. government entities and multiple U.S.

[6] Please refer to SCE's Test Year 2018 General Rate Case, A.16-09-001, Exhibit SCE-04, Volume 2, Workpapers Book A, pp. 115-116.
[7] Refer to A.16-09-001, Exhibit SCE-04, Volume 2, Workpapers Book A, pp. 117-120.
[8] For example, BlackEnergy malware was initially used to steal banking credentials, but later re-designed to attack the Ukraine power utilities in 2015. BlackEnergy summary *available at* https://attack.mitre.org/wiki/Software/S0089
[9] Attacks were conducted from computers with IP addresses allocated to the Russian Federation.
[10] More information on the 2015 Ukraine cyberattack is *available at* https://www.wired.com/2016/01/everything-we-know-about-ukraines-power-plant-hack/

critical infrastructure sectors. This included the energy, nuclear, water, and aviation sectors.[11]

3. Cyberattackers Targeting Electric Utilities

The cybersecurity risks facing SCE's ICS/SCADA systems continue to grow in quantity and complexity. Since 2009, reporting organizations have experienced an average annual increase of 124% for ICS/SCADA cybersecurity incidents, based on figures published by the Department of Homeland Security Industrial Control Systems Computer Emergency Response Team (DHS ICS-CERT). As the number of these attacks increases, attackers are also leveraging more advanced tactics specifically designed to exploit ICS/SCADA systems. Electric utilities, including SCE, are heavily targeted by adversaries that use cyberattacks to degrade capabilities.

Attacks on SCADA and ICS are garnering national attention. For example, in 2017, Robert Lee from the Dragos Corporation released information and testified before Congress about cybersecurity attacks on industrial targets within the United States from foreign nation-states.[12] In the last three years, the attacks have become more technically proficient, demonstrating advances in adversarial skills and tactics against industrial corporations and entities. If a large-scale cyberattack against a U.S. electric utility occurs, it may spur new legislation and regulatory requirements over and above what is currently in place with NERC CIP regulations.

Just like utilities across the countries that are seeking to protect, detect, and respond to this growing threat, SCE has been prudently enhancing its cyber capabilities. We plan to maintain these defense capabilities over the RAMP period and beyond.

B. Risk Bowtie

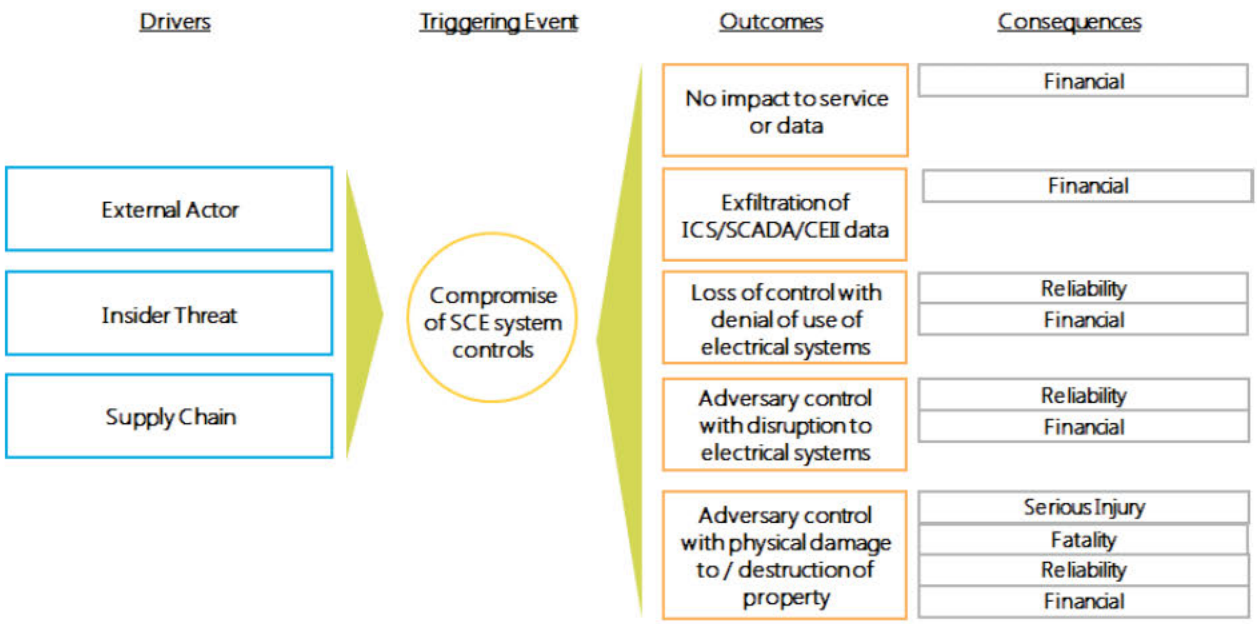
To define and evaluate the risk of cyberattack within SCE's environment, SCE has constructed a cyberattack risk bowtie, as shown in Figure II-1 below. Each component of the bowtie represents a critical data point in evaluating this risk. SCE explains these components in detail in the sections that follow.

---

[11] United States Computer Emergency Readiness Team (US-CERT), *available at* https://www.us-cert.gov/ncas/alerts/TA18-074A.

[12] Robert Lee's testimony at the hearing is *available at* https://www.energy.senate.gov/public/index.cfm/files/serve?File_id=5F40E0A2-B836-40EA-ACC6-9BF3B43A1B8F

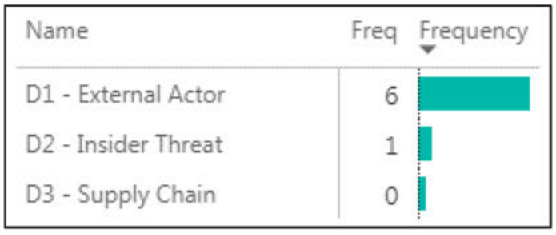
Figure II-1 – Cyberattack Risk Bowtie



C. Drivers

SCE identified three primary drivers that lead to SCE control systems being compromised: External Actor, Supply Chain, and Insider Threat. These drivers are detailed below. Figure II-2 shows the projected 2018 frequency counts for each of these drivers.[13]

Figure II-2 – 2018 Driver Frequency



Name	Freq	Frequency
D1 - External Actor	6	
D2 - Insider Threat	1	
D3 - Supply Chain	0	

1. D1 – External Actor

An external actor is defined as any outside entity (a person, organization, nation-state, etc.) that attempts to maliciously bypass SCE's cybersecurity controls. Depending on the actor, potential motives for this action can include:

- Gaining access to SCE's grid network;
- Disrupting service or supporting business operations;

[13] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on these drivers.

- Exfiltrating sensitive SCE or customer data;
- Achieving financial gain or extortion;
- Creating competitive advantage; or
- Inducing sabotage, terror, or harm.

2. D2 – Insider Threat

An insider threat is defined as an actor within SCE, such as an employee or contractor, who knowingly bypasses SCE cybersecurity controls with malicious intent. Potential motives for insider threat attacks generally include:

- Gaining access to SCE's grid network;
- Causing loss of control of operating assets;
- Obtaining a competitive advantage;
- Intending to harm SCE due to adverse prior experiences with SCE; and
- Stealing proprietary or sensitive information that can be sold or brokered in underground marketplaces.

3. D3 – Supply Chain

Potential attacks on the supply chain represent an emerging threat for SCE, and more broadly the electric utility industry. An attack through SCE's supply chain, whether targeted or untargeted, could occur as follows:

- Compromising SCE-procured goods with embedded malware or other malicious code. Once such malware or code is on SCE's network, it can disrupt service, leak sensitive data, or harm system controls.
- Attacking a third-party organization in SCE's supply chain, including vendors and business partners. Once the attack occurs, it can be exploited to violate the trust relationships between SCE and its partners.

4. Developing Driver Data[14]

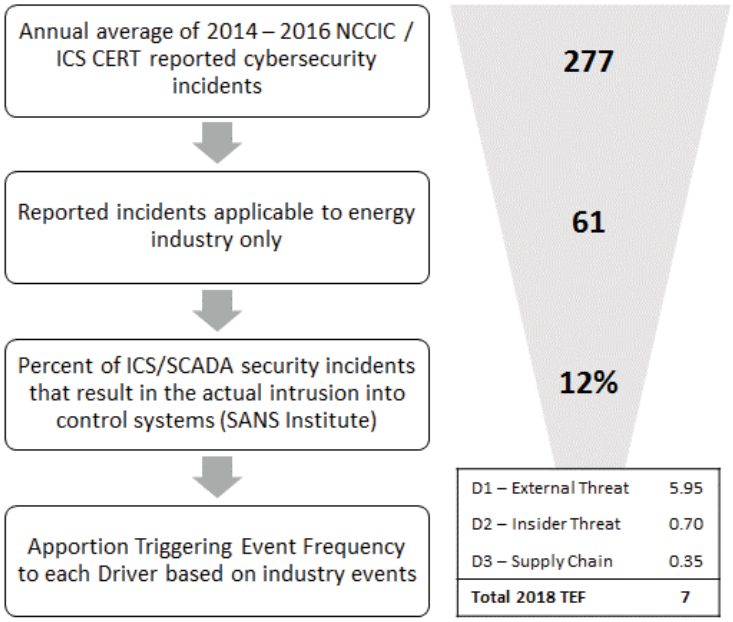
SCE identified the drivers that will continue to be the greatest threats to our operations. We evaluated these drivers using industry data. The availability of such industry data is necessarily limited. Similar to SCE, most utilities and companies that employ SCADA/ICS technologies are reluctant to disclose information or vulnerabilities, because such sharing this information may put their systems at greater risk of future attack. As such, where data was not

[14] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for more detail on the data and calculations used to develop driver data.

publicly available, we augment our analysis based on our relationships with several federal government defense agencies and industry experts.[15]

Figure II-3 summarizes how SCE determined triggering event frequency (TEF) and driver frequency for this RAMP analysis. A more detailed explanation follows the Figure.

Figure II-3 – Process Used to Develop 2018 TEF & Driver Data



SCE obtained the number of reported critical infrastructure incidents from the National Coordinating Center for Communications Integration Center (NCCIC) and Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) Annual Review Reports.[16] These organizations operate under the direction of the Department of Homeland Security (DHS). SCE then filtered this data for incidents within the Energy Sector. This data showed that the average annual reported incidents across the country for 2014-2016 was 277; with 61 of those coming from the energy industry.

[15] Please refer to WP Ch. 6, pp. 6.5 – 6.6 *(Subject Matter Expert Qualifications)* for additional detail on these experts.
[16] The ICS-CERT annual reports can are *available at* https://ics-cert.us-cert.gov/Other-Reports

SCE then used data from these reports, as well as information substantiated through the SANS - Securing Industrial Control Systems 2017 Report,[17] to determine that approximately 12% of ICS/SCADA security incidents result in actual intrusion into control systems.

SCE then sourced these control system intrusions to each of the three drivers. SCE has found that in many cases, available industry reports[18] vary in interpreting the source of the cyberattack incidents. Therefore, SCE supplemented our review of these reports with the experience of an industry consulting firm, to estimate the incident source (by driver) for 2018.

Finally, SCE applied growth rates[19] to each driver to account for the increase in volume of cyberattacks that were experienced over the 2011-2016 period, and the growth we estimate would occur if our proposed cyber defenses were not fully deployed. Table II-1 shows the projected growth of each driver over the RAMP period.

Table II-1 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	**Total**
Cyber Attack							
Baseline	**7.00**	**7.86**	**8.82**	**9.93**	**11.19**	**12.62**	**57.42**
Driver							
D1 - External Actor	5.95	6.74	7.62	8.63	9.77	11.06	**49.77**
D2 - Insider Threat	0.70	0.70	0.70	0.70	0.70	0.70	**4.20**
D3 - Supply Chain	0.35	0.42	0.50	0.60	0.72	0.86	**3.45**

D. Triggering Event

In the context of this risk assessment, the triggering event is defined as a "Compromise of SCE system controls." This results when a technological control fails, causing the loss of control, operability, or visibility of a process in a manner that impacts SCE operations. System controls are defined as grid components that interact with protection, switching, and distribution systems either on the grid or in an internal network. These can be firewalls, endpoint security

[17] This report is *available at* https://www.sans.org/reading-room/whitepapers/analyst/securing-industrial-control-systems-2017-37860

[18] For example: Idaho National Laboratory. Cyber Threat and Vulnerability Analysis of the U.S. Electric Sector, a*vailable at* https://www.energy.gov/sites/prod/files/2017/01/f34/Cyber%20Threat%20and%20Vulnerability%20Analysis%20of%20the%20U.S.%20Electric%20Sector.pdf

[19] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on these drivers growth rates.

software, network traffic inspection, Intelligent Electronic Device (IED), Remote Terminal Unit (RTU), Human Machine Interface (HMI), and similar technology.

E. Outcomes & Consequences

SCE identified a range of outcomes that would occur if our control systems were compromised. In developing these outcomes, we took into account evolving cyber threats and specific aspects of our grid infrastructure and operations. SCE estimated the expected likelihood of each outcome occurring, should the triggering event occur. This effort yielded the following outcome likelihoods as shown in Figure II-4:

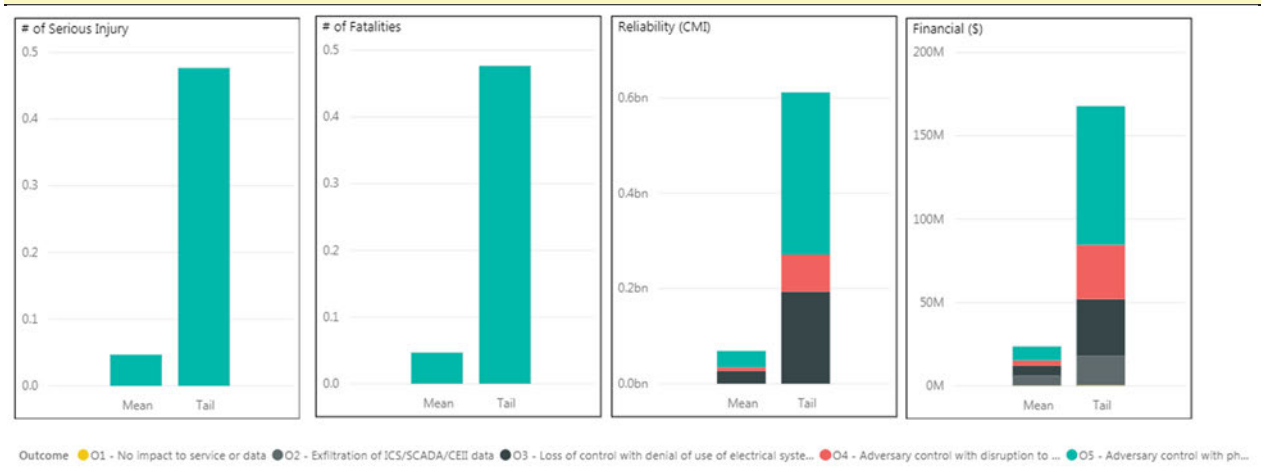
Figure II-4 – 2018 Outcome Likelihood

Outcome Percentage

Name	%	Percent
O1 - No impact to service or data	84.0 %	
O2 - Exfiltration of ICS/SCADA/CEII data	11.0 %	
O3 - Loss of control with denial of use of electrical systems	3.5 %	
O4 - Adversary control with disruption to electrical systems	1.0 %	
O5 - Adversary control with physical damage to /destruction of electrical system	0.5 %	

Figure II-5 illustrates the composition of the modelled baseline risk in terms of each consequence dimension. This shows that all of the safety consequences of this risk would be effectuated through O5 (Adversary control with physical damage to, or destruction of, the electrical system). In addition, the majority of the reliability and financial consequences originate from three outcomes: O3 (Loss of control with denial of use to electrical systems), O4 (Adversary control with disruption to electrical systems), and O5 (Adversary control with physical damage to, or destruction of, the electrical system). The sections that follow detail the inputs we used to arrive at these results.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (NU)



1. O1 – No impact to service or data

In this outcome, an attacker can breach our industrial control centers, yet do nothing. Anomalous activity, such as evidence of past intrusions or malware containment, does not directly affect SCE's ability to safely and reliably deliver power to its customers, although it can result in remediation costs. Remediation can involve external cybersecurity resources to determine if a more involved compromise occurred.

To take a real-life example, a small flood control dam[20] (Bowman Dam) in Port Chester, New York was targeted by Iranian adversaries, and its systems were exploited as part of a larger cyberattack against financial institutions. The compromised systems could have been used to cause flooding in the immediate surroundings. However, the sluice gate controls connected to the internal systems were deactivated at the time due to maintenance and repair. Therefore, there was no actual impact to safety or reliability. However, there were costs to remediate and patch the plant's IT systems.

Table II-2 shows the model input data and sources used, and the resulting annualized consequence impacts on a mean and tail-average basis. For example, based on the input data described in the table, the RAMP model provides annualized estimates of the actual consequences that would be incurred if this risk were left unmitigated. For O1, this translates to an annualized impact of approximately $212,000 in financial harm on a mean basis, or approximately $376,000 on a tail-average basis.

Table II-2 – Outcome 1 (No Impact to Service or Data): Consequence Details[21]

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*				SCE models this outcome by using an average cost per cybersecurity incident of $52,600. This divides the average annualized cost for cybercrime at utilities and energy sector companies ($17.2M as determined by Ponemon Institute & Accenture) by the number of projected incidents in 2017 (327, based on trend analysis from ICS-CERT reports).
Model Outputs	Mean				$211,518
	Tail-Average				$375,928

[20] *See* Joseph Berger, *A Dam, Small and Unsung, Is Caught Up in an Iranian hacking Case* (March 26, 2016) *available at* https://www.nytimes.com/2016/03/26/nyregion/rye-brook-dam-caught-in-computer-hacking-case.html

[21] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on the data supporting O1.

2. O2 – Exfiltration of ICS/SCADA/CEII data

In this outcome, an attacker obtains SCADA, ICS, or other CEII data from SCE's network. This can provide adversaries with advanced levels of knowledge on how our grid is designed and operated. This knowledge can be used to target specific operating units within the company and compromise their systems. When compromised, the target systems can be rendered inoperable. Then we must manually operate the systems (if it's even possible to do so) to maintain operability.

Table II-3 shows the model input data and sources used, and the resulting annualized consequence impacts on a mean and tail-average basis for this outcome. This translates to an annualized impact of approximately $5.8 million in financial harm on a mean basis, or approximately $17.8 million on a tail-average basis.

Table II-3 – Outcome 2 (Exfiltration of ICS/SCADA/CEII Data): Consequences Details[22]

Outcome 2		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*				According to a report by the Ponemon Institute and a related Data Risk Calculator from IBM, the cost for a data breach in the Energy Industry ranges from $3.4 million to $7.4 million depending on the number of compensating controls in-place for the specific energy utility. These costs include direct expenses such as hardware, software, and services remediation costs, hiring external data forensics and cybersecurity experts to determine the scope of breach and data compromised, and indirect expenses related to internal investigations and additional audit and assessment activity surrounding the breach.
Model Outputs	Mean				$5,796,828
	Tail-Average				$17,772,110

3. O3 – Loss of control with denial of use of electrical systems

Loss of electrical systems control due to denial of use has the potential to result in short-term effects, including:

- Disabling the connectivity between SCE transmission and distribution sites, requiring manned support for locations which are typically unmanned. This causes increased spending for overtime and less efficient manual transfers of connections.

[22] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on the data supporting O2.

- Disabling remote grid management functions. Then, our personnel must travel to the physical site locations to support restoring operations for affected components.

In an industrial environment, loss of control has a varied impact, which can range from lessened Overall Equipment Effectiveness (OEE) all the way up to complete process failure of generation, transmission, and distribution functions, and a resulting shutdown of operations.

Across the world, multiple cyberattacks in 2017 were attributed to malware which spread rapidly within companies and caused operational outages in transportation and manufacturing. This caused production failures by pharmaceutical company Merck[23] and transportation impacts for transportation company Maersk.[24] Denial of use attacks can potentially result in short-to-medium-term outages within SCE's territory.

Table II-4 – Outcome 3 (Loss of Control with Denial of Use to Electrical Systems): Consequences Details[25,26]

Outcome 3		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*			The 2015 Ukrenergo power distribution system cyberattack resulted in approximately 6 hours of electrical outage to 225,000 customers, or 81 million customer minutes of interruption.	SCE estimated the cost to recover and/or replace the IT hardware and software systems that would likely be affected after an attack of this magnitude.
Model Outputs	Mean			27,279,257	$6,091,732
	Tail-Average			194,493,969	$34,113,815

4. O4 – Adversary control with disruption to electrical systems

Adversary control that disrupts electrical systems occurs when an adversary successfully penetrates our systems and can execute controls in the same manner as SCE

[23] *See* Patrick Howell O'Neill , *Cyberscoop* article (October 27, 2017) *available at* https://www.cyberscoop.com/notpetya-ransomware-cost-merck-310-million/

[24] *See* Lee Mathews *NotPetya Ransomware Attack Cost Shipping Giant Maersk Over $200 Million* article (August 16, 2017), *available at* https://www.forbes.com/sites/leemathews/2017/08/16/notpetya-ransomware-attack-cost-shipping-giant-maersk-over-200-million/#4a518b794f9a

[25] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on the data supporting O3.

[26] There are obvious differences in the size and structure of SCE's and Ukrenergo's respective distribution systems. However, there are enough similarities between the two grids, in terms of equipment and devices used to control and operate the grid, that comparison is warranted. The Ukrenergo attackers compromised Remote Terminal Units (RTU) and digital relays to control the electrical system. SCE uses this same technology (from different vendors) in the grid network.

operators. This allows an attacker to control the flow of power, perform switching operations, and undertake other, similar actions. Such actions can prevent an electric utility from safely managing electric system operations, and can cause outages or periods of unstable power delivery to customers. When inputs, such as fuel or byproducts are involved, there is also the possibility of an unintended release of substances that could cause environmental consequences or harm to persons or property.

For example, in 2015 the Ukrenergo power company in Kiev, Ukraine was attacked by a nation-state adversary. This adversary utilized multiple cyberattack paths, including the network (spear phishing and BlackEnergy malware data collection), and telephone (Denial of Service aimed at the call center, thereby denying consumer data and impairing communications between facilities). The adversary was able to manipulate key functions of the SCADA and substation switching processes, causing power loss to approximately 225,000 customers.

Adversary control of our electric system could potentially result in short-to-medium-term outages within SCE's territory. SCE would also incur financial consequences associated with recovering and/or replacing the IT hardware and software systems that would likely be damaged after an attack of this magnitude. In addition, such an event would require a comprehensive forensic analysis, adversary eviction, and rapid mitigations to prevent similar incidents.

Table II-5 – Outcome 4 (Adversary Control with Disruption to Electrical Systems): Consequences Details[27]

Outcome 4		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			The 2015 Ukrenergo power distribution system cyberattack resulted in approximately 6 hours of electrical outage to 225,000 customers, or 81 million customer minutes of interruption.	SCE estimated the cost to recover and/or replace the IT hardware and software systems that would likely be affected after an attack of this magnitude.
Model Outputs	Mean			7,799,644	$3,303,492
	Tail-Average			77,776,571	$32,748,983

[27] Please refer to WP Ch. 6, pp. 6.1 – 6.4 *(Baseline Risk Assessment)* for additional detail on the data supporting O4. Also note, the relative magnitude of consequences in Outcome 4 may be less than Outcome 3 due to the much lower likelihood of Outcome 4 (1.0%) occurring than Outcome 3 (3.5%).

5. **O5 –** Adversary control with physical damage to, or destruction of, the electrical system

This outcome represents a reasonable worst-case scenario where an adversary successfully penetrates our cyber defenses, assumes control of our grid control system, and executes actions which damage or destroy portions of SCE's electric system or other property. Utilizing publicly available data, SCE could not find a reported instance of direct injury to a person or loss of life resulting from a cyber-related incident in the utility industry. However, SCE reasonably believes that such an attack is possible now or in the near future, and that adversarial entities are continually evaluating such possibilities.

As such, SCE evaluated scenarios where this outcome might occur on SCE's system. Due to prior vulnerabilities exposed by cyberattacks at hydroelectric facilities (Bowman Dam, for example), SCE evaluated the impact of a cyberattack on our hydroelectric generation system. SCE examined the potential impacts of a breach of our control systems which could potentially trigger the uncontrolled and rapid release of water and potentially lead to safety, reliability, and financial consequences. Beyond safety and reliability impacts, the potential costs resulting from this outcome would include capital spending to rebuild any damaged or destroyed hydroelectric equipment, as well as damage to other property located downstream of the event. This could include costs to rebuild roadways, bridges, and other facilities that could be impaired or destroyed by an uncontrolled release of water. In addition, SCE would have to repair and/or replace the SCADA/ICS infrastructure that was affected by the attack.

In addition, SCE evaluated the impacts of a potential coordinated cyberattack on multiple substations within our service territory. This scenario contemplates the financial and reliability impacts from an attack on three substations, similar to the attack contemplated within the Physical Security chapter.

Table II-6 – Outcome 5 (Adversary Control with Physical Damage to, or Destruction of, the Electrical System): Consequence Details[28]

Outcome 5		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE evaluated two potential cyber attack scenarios where an adversary obtains control of our grid assets and causes physical damage to, or destruction of, the electrical system. These scenarios include an attack on our hydroelectric system, as well as a coordinated attack on multiple substations.			
Model Outputs	Mean	0.05	0.05	34,250,455	$8,359,169
	Tail-Average	0.48	0.48	342,504,554	$83,591,685

[28] SCE's cybersecurity efforts are focused on protecting critical infrastructure. Therefore, a secure process for disclosing detailed tactics, techniques, and procedures is necessary to help ensure continued security and protection. As indicated above, if the Commission needs access to the information to answer specific questions regarding the cybersecurity risk, mitigations, and cost forecasts, SCE can provide an in-person briefing in a closed setting to provide more information.

III. Compliance & Controls

As cybersecurity threats significantly increase in volume and complexity year-over-year, SCE must continually adapt its defense strategies. SCE employs a defense-in-depth cybersecurity strategy. This strategy utilizes multiple layers of protection, and proactive vulnerability testing, to prevent unauthorized access and control of SCE's systems.

SCE organizes its cybersecurity defense into six program areas: Perimeter Defense, Interior Defense, Data Protection, SCADA Cybersecurity, Grid Modernization Cybersecurity, and North American Electric Reliability Corporation - Critical Infrastructure Protection (NERC CIP) Compliance. Each of these controls represents a risk reduction strategy to this cyberattack RAMP risk, and is described in more detail below.

Table III-1 summarizes the impact of each cybersecurity program mitigation on the drivers and outcomes identified in the cyberattack bowtie. This table presents a mapping of controls to those drivers and outcomes that are most heavily impacted by each mitigation. Each of these controls is composed of a number of projects and initiatives; however, due to the confidential nature of these efforts, we do not disclose or discuss each of these efforts individually.

Table III-1 – Inventory of Compliance & Controls[29]

Inventory of Controls		Driver(s)	Outcome(s)	Consequence(s)	2017 Recorded Costs ($M)	
ID	Name	Impacted	Impacted	Impacted	Capital	O&M
CM1	NERC CIP Compliance	Not Modeled	Not Modeled	Not Modeled	$ 0.1	
C0	Common Cybersecurity Solutions	Not Modeled	Not Modeled	Not Modeled	$ 0.2	
C1	Perimeter Defense	D1, D2	All	All	$ 18.2	
C2	Interior Defense	D2, D3	All	All	$ 10.1	$ 12.8
C3	Data Protection	All	O2	F	$ 10.4	
C4	SCADA Cybersecurity	All	O3, O4, O5	All	$ 10.6	
C5	Grid Modernization Cybersecurity	All	O3, O4, O5	All	$ 15.0	

CM: Compliance (Activity required by law, regulation, etc. As discussed in Chapter I - RAMP Overview, SCE does not model compliance activities in this RAMP report.)
C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE risk-models control in the RAMP report.)
Consequence Abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial - F

[29] Please note that in this table, SCE maps how each control impacts drivers, outcomes, and consequences. For purposes of modeling in the RAMP report, SCE only adjusts outcome probabilities over time. Also, SCE has historically tracked O&M at a portfolio level, and not by each control.

A. CM1 – NERC CIP Compliance

NERC CIP Compliance is an existing compliance control. This program continues the ongoing implementation of systems and processes that help SCE comply with the evolving cybersecurity-related NERC CIP requirements. These systems and processes will improve how we manage facility access, maintain asset change control, and control physical access.

B. C0 – Common Cybersecurity Solutions (CCS) for Generator Interconnections

This control was implemented from 2012 – 2017. Each device on the electric grid secured by CCS will have a unique key to enable secure communications with its control system. This approach mitigates the risk that an attacker can seize control of the electric grid from an individual device, such as a relay or capacitor bank controller. It also lets SCE rapidly identify and respond to a cybersecurity event.

The CCS project also enhances cybersecurity protections for critical generator interconnections. The applications on these interconnection paths require low latency[30] to transmit data to back-office systems. We must retain control of the communications, because these systems make automated control decisions on the electric grid. The CCS system is specially designed to provide cybersecurity protection over the communication paths, while maintaining the performance requirements to enable capabilities of low latency control systems.

C. C1 – Perimeter Defense

Perimeter Defense is the first line of defense against cyberattacks. It is the outer layer of protection for our defense-in-depth approach to cybersecurity. It represents the processes, procedures, hardware, and software to protect critical systems such as SAP, customer data, and ultimately our grid from unauthorized access. When properly configured, the perimeter defenses should only permit those activities required to conduct business. In a perimeter defense security model, the perimeter technology prevents, absorbs, or detects attacks, thereby reducing the risk to critical back-end systems. Cybersecurity perimeter defenses include technologies such as firewalls and intrusion detection systems.

In addition, the Perimeter Defense program will continue to refine existing intrusion protection measures and implement new ones (such as systems with deep-scanning capabilities and advanced data analytics capabilities). This will help us more ably detect nefarious activity.

[30] Low latency refers to systems that require having a very low time interval between when a message is sent and when it is received.

This project will integrate these new tools and controls into our existing Perimeter Defense layer to create common, unified monitoring that lets us rapidly respond to security events.

1. Drivers Impacted

Perimeter Defense reduces the frequency of all drivers by, among other things, intercepting attempted communications and attacks from external attackers. It also helps us determine whether external communications are intended to harm SCE, including whether the communication is an attempt to trick or coerce a user into clicking internet links or providing information.

2. Outcomes & Consequences Impacted

Perimeter Defense also reduces the impact to all outcomes by preventing attacks from reaching and impacting other internal defense capabilities. Perimeter Defense addresses the initial attack step that is taken in most adversary campaigns, which is to utilize phishing messages or other social engineering tactics to:

- Convince or coerce an internal user to open a malicious e-mail attachment;
- Click on a Uniform Resource Locator (URL) that links to malware; or
- Trick the user into providing sensitive information such as user credentials to the attacker, or to an attacker-controlled website.

Perimeter Defense identifies and either automatically prevents the communication or alerts the user.

3. Control Options Modeled for C1 (Perimeter Defense)

Perimeter Defense is a core control within our defense-in-depth cybersecurity strategy. As such, when evaluating alternatives to this control, SCE contemplated different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools associated with the deployment of this control over the RAMP period. These options are represented through C1a, C1b, and C1c, which are variants of the Perimeter Defense control, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options, and uses those results to build our proposed and two alternative mitigation plans.

D. C2 – Interior Defense

Interior Defense is a set of protection controls that are needed to:

- Secure SCE's internal business systems from unauthorized users, devices, and software that are attempting to access SCE's business systems; and
- Utilize analytics to prevent attacks from happening before they start.

Interior Defense efforts also help identify and block security breaches from personnel who already have authorized access to the systems. Users of SCE's business systems can propagate and/or launch malware[31] knowingly or unknowingly. Without the Interior Defense controls, SCE could not identify or react to an infected computer or malicious breach attempting to infect others on the network. By quickly identifying suspicious activity, SCE can take earlier action to minimize any potential damage from the attack.

The Interior Defense mitigation lets us monitor SCE's internal business network, in real-time and with advanced and integrated capabilities. This makes it difficult for unauthorized users to access our systems, and also protects against authorized users knowingly or unknowingly propagating cybersecurity attacks. This mitigation also make it harder for rogue devices or software to access SCE systems and confidential data or to cause business disruption. The mitigation will also address Advanced Persistent Threats (APT)[32] by using advanced data collection and analysis technologies that can quickly detect potential questionable activity.

To accomplish all of this, the Interior Defense mitigation program will:

- Extend SCE's Identity and Access Management system to newer generation security technology;
- Enhance and expand SCE's data collection capabilities to retrieve (and, as needed, collect) disparate pieces of data to form a clear picture of threats and attacks;
- Implement technology capabilities so that SCE can analyze collected information for security threats in a more automated and effective manner; and
- Initiate automated alerts when questionable activity is detected. This will let us stay ahead of possible threats and help prevent attacks from happening.

1. Drivers Impacted

Interior Defenses are designed to reduce D2 (Insider Threat), as well as any external threat D1 (External Actor) or D3 (Supply Chain) threat that successfully bypasses the Perimeter Defenses. A threat that originates on or accesses the SCE internal network will be neutralized by Interior Defense at the endpoint (workstation, laptop, or server). When an attack occurs to a system that is directly connected to the SCE internal network via physical interface, we counter the attack through access controls that disallow unauthorized systems.

[31] Malware is software that is intended to damage or disable computers and computer systems.
[32] Advanced Persistent Threats (APT) mean a network attack where an unauthorized person gains access to a network and remains undetected on the network for a long period of time. Typically, an APT attack is launched to steal data rather than to damage the network or organization.

2. Outcomes & Consequences Impacted

Interior Defense affects all outcomes. All attack paths require that Interior Defenses be bypassed regardless if the attacker is attempting physical or network access. Interior Defense prevents malware and malicious software from spreading once they are inside SCE.

3. Control Options Modeled for C2 (Interior Defense)

Interior Defense is a core control within our defense-in-depth cybersecurity strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. These options are represented through C2a, C2b, and C2c, which are variants of the Interior Defense control, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options. The results inform our Proposed Plan and the two alternative mitigation plans.

E. C3 – Data Protection

The Data Protection program safeguards the computing environment housing SCE's core information. Among other things, this program will protect confidential SCE information that resides on all computing devices from unauthorized use, distribution, reproduction, alteration, or destruction.

The Data Protection program will leverage specialized technology to better protect and encrypt data fields within files, enhance access controls to protect sensitive business information, and secure business information stored at external sites that host SCE business systems. In addition, this mitigation program will implement enhanced controls for granular data protection by deploying Data Loss, Categorization, and Identification tools. These controls will:

- Automate data classification by tying together the different systems that contain data and the ability to classify them;
- Monitor and alert unauthorized access to business information by leveraging the monitoring and data analysis environment with new toolsets;
- Manage business information that is saved on personal devices;
- Manage and restrict the copying of business information to portable devices.

1. Drivers Impacted

All Drivers are impacted by the functions provided by this mitigation. The use of data classification and role-based access controls prevents unauthorized users and attackers from accessing sensitive SCE information.

2. Outcomes & Consequences Impacted

Outcome 2 (Exfiltration of ICS/SCADA/CEII data) is primarily affected by Data Protection, which restricts access to specifically-classified SCE data to a limited group of users. This blocks an attacker that is trying to locate valuable information about SCE's operations or customers in order to sell or release that information.

3. Control Options Modeled for C3 (Data Protection)

Data Protection is a core control within our defense-in-depth cybersecurity strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. These options are represented through C3a, C3b, and C3c, which are variants of the Perimeter Defense control, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options. The results inform our Proposed Plan and the two alternative mitigation plans.

F. C4 – SCADA Cybersecurity

This project provides enhanced security measures by implementing risk-reduction methods specifically tailored for SCE's SCADA systems. SCE's SCADA systems remotely control and monitor the electric grid.

SCADA Cybersecurity protects legacy and future industrial control systems that are currently connected via routable networks. We need better visibility, detection, and protection controls to secure these environments from evolving threats. This control does the following:

- Builds a secure network to protect the administrative interfaces of critical tools;
- Develops device access controls to secure how operators interact with control systems;
- Develops user access controls to secure role-based access to least-required privileges.[33] This is a more secure profile for user access;
- Implements next generation malware protections to identify malware;
- Deploys vulnerability management tools to search for and identify known vulnerabilities;
- Provides data encryption services;
- Develops system monitoring services;
- Implements threat intelligence integration tools that can automatically take in intelligence to monitor and analyze potential and actual threats; and

[33] The Principle of Least Privilege is the idea that no more than the very minimum number of people should have access to information and resources as necessary for legitimate purposes.

- Procures government-sponsored secure technology to defend against advanced attacks.

1. Drivers Impacted

All three Drivers are impacted by this mitigation. SCADA protection makes it far more difficult for attackers to enter the electric grid network without proper credentials. External actors and the supply chain must pass through controls that are similar to Perimeter Defense, but applied at the edge of the grid network. Insider Threat actors will also be challenged by this mitigation.

2. Outcomes & Consequences Impacted

This mitigation affects outcomes O3 (Loss of control with denial of use of electrical systems), O4 (Adversary control with disruption to electrical systems) and O5 (Adversary control with physical damage to / destruction of electrical system). SCADA protection assesses the network at periodic intervals to help make sure that new vulnerabilities are not present. In addition, there are network visibility points that can be used to monitor, and provide alerts on, various conditions that may indicate abnormal operations or the presence of an attacker. Like Data Protection and Internal Defense, there are role-based access control measures to prevent unauthorized SCE users from modifying the grid environment.

3. Control Options Modeled for C4 (SCADA Cybersecurity)

SCADA Cybersecurity is a core control within our defense-in-depth cybersecurity strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. These options are represented through C4a, C4b, and C4c, which are variants of the Perimeter Defense control, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options. The results inform our Proposed Plan and the two alternative mitigation plans.

G. C5 – Grid Modernization Cybersecurity

Grid Modernization Cybersecurity will protect our distribution systems by detecting, isolating, fixing or removing, and restoring compromised systems and devices to normal as quickly and efficiently as possible.

Modernizing the electric grid will lead to new capabilities to support the evolving use of the distribution system. This will require many new applications that extend grid networks into a two-way relationship with customers and third parties. The distributed intelligence from grid modernization presents new cybersecurity challenges. Addressing these cybersecurity

challenges requires a combination of infrastructure, applications, and threat intelligence initiatives.

Infrastructure service layers are needed to extend strong cybersecurity controls to the edges of the grid network. New grid applications must be designed with cybersecurity controls throughout their lifecycle by integrating strong access controls, secure communications, and secure programming code. Integrating cybersecurity operations with external threat intelligence-sharing organizations will help us more effectively respond to incidents and improve our investigation capabilities.

Also, cybersecurity must be integrated into each component of grid modernization. Grid Modernization Cybersecurity will defend against known cybersecurity threats by implementing controls and protections, including:

Secure Administration Environments: Cybersecurity adversaries primarily target privileged credentials, such as system administrators and super users.[34] Losing control of these accounts can result in catastrophic system failures and prolonged service outages. The most common attacks on these accounts are privilege escalation attacks or malicious insiders. Designing secure administration environments helps prevent and deter these threats.

Device Access Controls: A fundamental cybersecurity control involves profiling, authenticating, and monitoring devices connected to the network. Forcing an attacker to launch an attack from a compromised SCE-controlled device is far easier to defend against than a device that the attacker itself has designed. Additionally, IP-connected devices that are located outside of physically secure buildings (such as cameras or control systems in the spaces where electrical components are stored and deployed) can be impersonated and their connections used to launch an attack. This mitigation will address these threats.

User Access Controls: Among other things, this effort will protect against improper control of grid system operations.

Advanced Malware Protections: Current grid system networks primarily employ a blacklisting strategy (signature-based virus scanning) to protect against malware. Blacklisting strategies are only able to detect *known* malware. As shown in both the Stuxnet[35] and

[34] Super users have special privileges that allow them to make changes to access and configurations within and across systems.

[35] Stuxnet is malware designed to target the Siemens Programmable Logic Controllers (PLCs) connected to Iranian uranium enrichment centrifuges that degraded the quality of the output while damaging the centrifuges. *See* David Kushner, *The Real Story of Stuxnet* (February 26, 2013), *available at* https://spectrum.ieee.org/telecom/security/the-real-story-of-stuxnet.

BlackEnergy attacks on critical infrastructure (discussed above), an attacker will very likely customize malware to avoid being detected by blacklisting systems. Since grid systems are more rarely reprogrammed or updated than business networks, grid computer systems are ideal for taking a whitelisting[36] approach. Application whitelisting authorizes a specific set of applications and processes to run on a given system while preventing all other applications or code from executing. This effort will comprehensively implement this approach across grid system networks wherever feasible.

Vulnerability Management: Since the beginning of software development, mistakes have been made in code or security control oversights that render a system vulnerable to a known attack. These attacks can be logged in a publicly available repository that contains computer and software vulnerability information. A vulnerability management system (VMS) is critical to tracking known vulnerabilities and facilitating remediation.

1. Drivers Impacted

All drivers are impacted by this mitigation, since it applies multiple layers of protection at the edge of the access to our network, as well as internally within the SCE grid environment. The mitigation prevents unauthenticated users and unauthorized SCE personnel from accessing the network. The mitigation also allows us to monitor different network connection and transportation types (such as fiber and radio frequency) for misuse.

2. Outcomes & Consequences Impacted

Components of this mitigation have impacts on outcomes O3 (Loss of control with denial of use of electrical systems), O4 (Adversary control with disruption to electrical systems) and, O5 (Adversary control with physical damage to / destruction of electrical system). User Access Controls prevent an attacker from using default credentials to access the grid environment. Advanced Malware Protection prevents attackers' programs from running on grid assets. And Device Access Controls restrict the pathways that an attacker can use in attempting to move through the grid network towards more critical components. (This is what the attackers did in the NotPetya malware attack and the 2015 Ukraine electrical outage attack.)

3. Control Options Modeled for C5 (Grid Modernization Cybersecurity)

Grid Modernization Cybersecurity is a core control within our defense-in-depth cybersecurity strategy. When evaluating alternatives to this control, SCE examined different options, or levels, of penetration testing, vulnerability assessments, training, labor and non-labor resources, and other cyber tools to deploy this control. These options are represented

[36] Whitelisting involves controls within software that permit known valid applications and code to run while prohibiting unknown or untrusted applications and code from running.

through C5a, C5b, and C5c, as shown in Table I-2. SCE models the risk reduction and RSE associated with each of these control options. The results inform our Proposed Plan and the two alternative mitigation plans.

IV. Mitigations

In the normal course of business, and as part of developing this RAMP report, SCE continually identifies more effective ways to mitigate this risk. Many of these new approaches are specific projects or tools that are incorporated into each program discussed in Section III above. While SCE continually evaluates and incorporates new and innovative projects and tools into each control program, we believe we cannot publicly disclose the details of these efforts.[37]

As part of the RAMP process, SCE did identify and evaluate a potential new mitigation opportunity that in the future could help address a growing cybersecurity risk. Please see Table IV-1 below.

Table IV-1 – Inventory of Mitigation[38]

Inventory of Mitigations		Driver(s)	Outcome(s)	Consequence(s)	Mitigation Plan		
ID	Name	Impacted	Impacted	Impacted	Proposed	Alt. #1	Alt. #2
M1	Accelerated Hardware Refresh	All	All	All			x

M: Mitigation (Activity commencing in 2018 or later to affect this risk. SCE risk-models mitigations in this RAMP report.)

A. M1 – Accelerated Hardware Refresh

With the discovery and release of the design flaws in Intel and AMD processors named Meltdown and Spectre[39] there is a high probability that attackers will be developing software[40] to target these vulnerabilities. The vulnerabilities are present in an extremely large section of computing hardware. Currently, neither Intel nor AMD has issued processors for sale that are immune to this new class of vulnerability. As such, processor design vulnerabilities will likely

[37] SCE's cybersecurity's efforts are focused on protecting critical infrastructure. Therefore, a secure process for disclosing detailed tactics, techniques, and procedures is necessary to help ensure its protection. As discussed above, SCE can provide an in-person briefing in a closed setting upon request.
[38] Please note that in this table, SCE maps how the mitigation impacts drivers, outcomes, and consequences. For purposes of modeling this mitigation in RAMP, SCE only adjusts outcome probabilities over time.
[39] *See* Peter Bright, Meltdown and Specter: Here's what Intel, Apple, Microsoft, others are doing about it (January 5, 2018), *available at* https://arstechnica.com/gadgets/2018/01/meltdown-and-spectre-heres-what-intel-apple-microsoft-others-are-doing-about-it/
[40] *See* David Fisher and William G. Sanchez, *Detecting Attacks that Exploit Meltdown and Spectre with Performance Counters*,(March 13, 2018) *available at* https://blog.trendmicro.com/trendlabs-security-intelligence/detecting-attacks-that-exploit-meltdown-and-spectre-with-performance-counters/

become known as "forever day" vulnerabilities[41] that may never be remediated in existing hardware with a longer-than-average refresh cycle period, such as industrial control systems (ICS) and related components within the grid environment.

To plan for such an event, this mitigation would accelerate the technical hardware refresh from the existing four-year cycle to a one- to two-year cycle, prioritized by business area. This would allow SCE to replace the vulnerable hardware with systems that are hardened and protected against the specific Meltdown and Spectre vulnerabilities, as well as the new class of processor design flaws.

1. Drivers Impacted

This mitigation will directly impact the viability of all three drivers in the cyberattack risk bowtie.

2. Outcomes & Consequences Impacted

This mitigation can serve to stop cyberattacks from advancing from Outcome 1 (No impact to service or data) to Outcome 5 (Adversary control with physical damage to / destruction of electrical system). As such, M1 will affect all outcomes and associated consequences.

[41] Due to the increased longevity of industrial equipment and control systems compared to the general-purpose computing platforms of IT, vulnerabilities are not easily fixed by manufacturer and vendor software patches or by releasing a new version of the technology. The threat will persist much longer in the Industrial Control System (ICS) networks. A critical vulnerability may never get patched or remediated in an ICS environment, and therefore may forever be at risk of being exploited. *See* Dan Goodin, *Rise of " forever day" bugs in industrial systems threatens critical infrastructure* (April, 9, 2012), *available at* https://arstechnica.com/information-technology/2012/04/rise-of-ics-forever-day-vulnerabiliities-threaten-critical-infrastructure/

V. Proposed Plan

Cybersecurity is inherently difficult to quantify. The risks and threats that we face as a utility in one of the largest metropolitan cities[42] in the world are vast and diverse. Trying to forecast the probability of successful breaches of our systems controls involves making a series of educated assumptions based on what we know about our existing defenses, the demographics and capabilities of our attackers, and the growth and complexity of the attacks we will face in the future. In addition, the risk of cyberattack has the potential to change significantly due to global politics and the associated actions of nation states. Cybersecurity threats are not limited to our service territory, but instead can originate from virtually anywhere across the world. Cybersecurity challenges can also be triggered or motivated by social unrest, political differences and upheavals, and religious and cultural factors.

Measuring the effectiveness of controls and mitigations becomes equally difficult when we don't have a base level of historical data and experience to draw from. Fortunately, SCE has not experienced a significant breach of our control systems yet.

Through the development of this RAMP report, SCE was able to take initial steps forward in quantifying the cyberattack risk to SCE, as well as the effectiveness of our controls and mitigations. This is truly a first-generation model, but one that SCE believes provides a strong foundation upon which to improve in the future.

SCE analyzed, from a historical perspective, the relative effectiveness of our cybersecurity controls and mitigations in addressing SCADA/ICS attacks that have occurred around the world over the past few years.[43] SCE used this analysis to inform the mitigation evaluation and risk spend efficiency calculations.

SCE has evaluated each control and mitigation discussed in Sections III and IV and has developed a Proposed Plan for addressing this risk, as shown in Table V-1 below.

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[42] Los Angeles, as a service area, comprises a high density of customers to geographic areas, headquarters a great deal of the media/entertainment industry, and has a high profile in the news. Thus, a cyberattack in Los Angeles will be a much more reported-upon event and will provide the attackers with relatively higher visibility.

[43] Please refer to WP Ch. 6, pp. 6.7 – 6.9 *(Outcome-Based Risk Reduction Model Overview)* for further detail on this cyberattack outcome-based risk assessment.

Table V-1 – Proposed Plan (2018 - 2023 Totals)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Mean (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1a	Perimeter Defense	2018	2023	$80.8	$34.9	1.51	0.013	9.13	0.079
C2a	Interior Defense	2018	2023	$47.9	$23.7	0.91	0.013	5.83	0.082
C3a	Data Protection	2018	2023	$30.7	$16.7	0.02	0.000	0.03	0.001
C4a	SCADA Cybersecurity	2018	2023	$19.8	$19.9	0.46	0.012	3.04	0.077
C5a	Grid Modernization Cybersecurity	2018	2023	$169.2	$33.8	1.41	0.007	9.28	0.046
		Total - Proposed Plan		**$348.4**	**$129.0**	**4.31**	**0.009**	**27.32**	**0.057**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend).

A. Overview

SCE evaluated our internal defenses against cyberattack capabilities and threats. This evaluation indicated that SCE has implemented adequate cyber defense strategies for the threats that exist today. However, through developing this RAMP report, we have identified increased exposure and risk in the future. As such, in the Proposed Plan, SCE continues to deploy and enhance its defense-in-depth cybersecurity approach by maturing and expanding existing cybersecurity practices. In addition, SCE supplements this work with enhanced capabilities, tools, and resources to address the growth of cyberattack risks at a reasonable level of spend.

The Proposed Plan carries forward the scope of work from our existing activities, and adds additional training, penetration testing, and vulnerability assessments. Training is essential in helping ensure that SCE personnel are up-to-date on the latest technology and techniques used to protect and operate the grid network. Vulnerability assessments performed by independent and trusted third parties evaluate how SCE manages risks associated with vulnerabilities in the network environments. These assessments can also serve as checkpoints for ongoing projects. Use of penetration testing allows SCE to see:

- What an adversary would identify as key assets for compromise;
- What attack paths and techniques apparently would succeed within the SCE environment; and
- How practically effective the security mitigations are in preventing, mitigating, or detecting an attack.

B. Execution feasibility

SCE evaluated the feasibility of executing the Proposed Plan based on current organizational capabilities and the technical limitations of our internal computing and operational systems. The Proposed Plan is feasible and prudent to execute.

C. Affordability

The Proposed Plan strikes a reasonable balance between cost and risk reduction. This plan is only slightly more expensive (<5%) than the Alternative Plan #1, but delivers nearly twice the amount of risk reduction. In addition, the RSE of this plan is approximately 40% greater than the Alternative Plan #1.

The Proposed Plan does not deliver as much risk reduction, nor at the level of RSE, as Alternative Plan #2 does. However, Alternative Plan #2 requires much greater costs to deliver these benefits.

SCE contemplated whether to pursue Alternative Plan #2, but chose not to for the following reasons: (1) SCE must balance the need to invest in cybersecurity on the one hand, versus the need to spend to address other risks and meet other important objectives on the other hand; (2) at this time, our evaluation indicates that the Proposed Plan represents a reasonable level of commitment and spend over the RAMP period; and (3) SCE does not believe that deploying M1-Accelerated Hardware Refresh (a notable feature of Alternative Plan #2) is an operationally practical, technologically mature, or fiscally prudent choice at this time. This is discussed further in Section VII, where we examine Alternative Plan #2 in more detail.

D. Other Considerations

Advances in the sophistication of cyberattack threats and the deployment of new attack methods may render the Proposed Plan ineffective. SCE must predict where the threat will go in the future. If we have not predicted this correctly, the mitigations laid out in the Proposed Plan may not be sufficient. In addition, global politics, social unrest, and war can potentially lead to increased numbers of, and greater sophistication of, attacks by nation-states on our electric system. As discussed previously, SCE builds, maintains, and operates critical energy infrastructure that could be more susceptible to attack should the global environment change.

VI. Alternative Plan #1

SCE evaluated other options to address the cyberattack risk and developed an alternative mitigation plan as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018 - 2023 Totals)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Mean (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1b	Perimeter Defense	2018	2023	$80.8	$37.8	0.68	0.006	3.97	0.033
C2b	Interior Defense	2018	2023	$47.9	$22.7	0.59	0.008	3.79	0.054
C3b	Data Protection	2018	2023	$30.7	$15.4	0.01	0.000	0.01	0.000
C4b	SCADA Cybersecurity	2018	2023	$19.8	$9.2	0.17	0.006	1.12	0.039
C5b	Grid Modernization Cybersecurity	2018	2023	$169.2	$26.4	0.74	0.004	4.82	0.025
		Total - Alternative Plan #1		**$348.4**	**$111.5**	**2.19**	**0.005**	**13.72**	**0.030**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend).

A. Overview

Similar to the Proposed Plan, the Alternative Plan #1 continues to deploy SCE's defense-in-depth cybersecurity approach. This plan then adds modest incremental resources (fewer than the Proposed Plan) to increase certain cybersecurity capabilities to address a growing cyber threat.

B. Execution Feasibility

The Alternative Plan #1 represents a reduced scope of work for each mitigation program relative to the Proposed Plan. Since SCE believes the Proposed Plan can be executed, this plan should likewise be feasible to execute.

C. Affordability

This Alternative Plan #1 represents the least-cost option. While this is the least-cost option, the risk spend efficiency for this plan is the lowest out of the three mitigation plans identified. Alternative Plan #1 provides the lowest amount of funding for cybersecurity testing and will limit strategic upgrades to newer technologies.

If we eliminate or reduce vulnerability assessments and penetration tests, we will decrease the security capabilities of our IT networks. We will not be able to independently evaluate and proactively remediate technical vulnerabilities that can be exploited by an attacker to compromise SCE assets.

D. Other Considerations

As discussed in the Proposed Plan, if we have not adequately predicted the growing threat, the mitigations laid out in this plan may not be sufficient.

VII. Alternative Plan #2

SCE evaluated other options to address this risk and developed another alternative mitigation plan as shown in Table VII-1.

Table VII-1 - Alternative Plan #2 (2018 - 2023 Totals)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Mean (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1c	Perimeter Defense	2018	2023	$80.8	$50.0	1.61	0.012	9.88	0.075
C2c	Interior Defense	2018	2023	$47.9	$30.0	1.67	0.021	10.76	0.138
C3c	Data Protection	2018	2023	$30.7	$20.9	0.02	0.000	0.03	0.001
C4c	SCADA Cybersecurity	2018	2023	$19.8	$11.5	0.43	0.014	2.82	0.090
C5c	Grid Modernization Cybersecurity	2018	2023	$169.2	$32.4	1.76	0.009	11.70	0.058
M1	Accelerated Hardware Refresh	2018	2023	$58.1	$0.0	0.44	0.008	2.84	0.049
			Total - Alternative Plan #2	**$406.5**	**$144.8**	**5.92**	**0.011**	**38.03**	**0.069**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend).

A. Overview

Alternative Plan #2 represents the most aggressive approach to expanding our cybersecurity defenses. This plan expands investing in our defense-in-depth controls (C1 – C5), and encompasses investing in a new mitigation, M1 (Accelerated Hardware Refresh). This new mitigation will address hardware-level vulnerabilities that exist in Intel and AMD processors made in the last 20 years.[44] In developing this plan, SCE considered global events, political situations, technological advancements, the rapid incorporation of technology into and across our business, and the persistent advancement of threats against our business.

B. Execution feasibility

While possible, this plan would require a significant operational effort to execute in short order. SCE would have to identify, evaluate, procure, and train a larger number of cybersecurity experts in a shorter period of time than in the Proposed Plan. This may prove difficult in a cybersecurity market that is already facing resource shortages. In addition, the number of additional, valuable tools that would need to be procured through this plan would require time and coordination to test, install, and deliver across the enterprise.

[44] The Pentium Pro (released in 1995) was the first Intel processor to use speculative execution, which is the basis for the Meltdown and Spectre related vulnerabilities. AMD processors are built with the same capabilities. *See* Joel Hruska, *What is Speculative Execution* (January 10, 2018) *available at* https://www.extremetech.com/computing/261792-what-is-speculative-execution.

Finally, this mitigation plan includes mitigation M1 (Accelerated Hardware Refresh), which would reduce the period of time between laptop and personal computer refreshes within SCE. That period is roughly four years today, and would drop to roughly two years going forward. While the benefits of this mitigation could be significant, the operational implications of executing this mitigation could be equally as significant. Although the vulnerabilities of some models of processor hardware have been successfully identified, the capability of widespread attack has not been demonstrated.

SCE carefully considered the operational factors, personnel disruption, and financial considerations of this plan. We determined that in light of the risk factors and the relatively early stage of maturity of M1 (Accelerated Hardware Refresh) technologies, this may not be the prudent time to execute. In looking at the expected risk for a widespread event that could take advantage of discovered and potential undisclosed vulnerabilities, we believe that the additional spend is not currently justified. SCE will continue to monitor the status of the supply chain threat to determine if the risk increases. If the vulnerability impact increases, then SCE will reconsider this analysis and this mitigation option.

C. Affordability

This is the highest-cost plan that we considered. This plan also provides the greatest scope of work to increase our cyber defenses, and is forecast to reduce the most risk. The risk spend efficiency of this plan is comparable to the Proposed Plan, and higher than Alternative Plan #1. Due to the maturity of the technologies required to deploy this Alternative Plan #2, SCE could not justify the additional expenditures at this time.

D. Other Considerations

As discussed in the Proposed Plan, if we have not predicted the growing threat accurately enough, the mitigations laid out in Alternative Plan #2 may not represent the correct fit.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

Modeling the risk of cyberattacks and the effectiveness of cybersecurity controls and mitigations was a challenge.

In examining asset-based risks, we can evaluate actual failure rates and equipment conditions, and leverage decades worth of utility data and information related to the performance on an asset. In contrast, cybersecurity does not have a similar breadth of data that we can draw upon when analyzing the risks. Additionally, unlike most asset-based risks, cyberattacks are ever-evolving; what we know today may not be applicable to where the threat goes tomorrow, a year from now, or five years from now. As a result, SCE had to leverage industry data wherever possible, develop prudent assumptions, and consult with industry experts to validate our approach to this risk evaluation.

SCE recognizes that not capturing indirect, or secondary impacts from risk events can underestimate the potential magnitude of a risk. This is especially true for the cyberattack risk. If a cyberattack were to successfully compromise the grid and cause a widespread and extended blackout, there are very real safety and financial consequences that would result. These impacts are not captured in this chapter. We look forward to evaluating this issue further, to determine if there is a way to reasonably and credibly incorporate these indirect impacts into future risk analyses.

B. Data Collection & Availability

Most organizations, especially those in the utility and energy sector, are reluctant to share sensitive data on their cybersecurity operations and defenses. SCE faced two data challenges in this RAMP filing. First, most of the data that we do have relating to our control systems cannot be shared publicly. Doing so would expose our critical systems to attack. As such, the data that we can share as part of this RAMP filing related specifically to SCE is limited. Second, to our knowledge, most utility and energy companies follow the same data sensitivity protocols as we do. It can be very difficult to find relevant industry data, when most companies do not report and expose their vulnerabilities publicly.

C. Performance Metrics

SCE has a corporate goal around protecting critical infrastructure and customer data. SCE also collects internal cybersecurity metrics to measure the effectiveness of our cybersecurity

efforts and the threats that we are seeing against our company. Some examples are metrics related to our enterprise phishing exercises, patching, and number of penetration attempts on the network.

In addition, there are several emerging metrics such as utilizing the Department of Energy Electric Sector Cybersecurity Capability and Maturity Model (C2M2). This model helps organizations evaluate, prioritize, and improve cyber capabilities. SCE uses a third party security vendor to conduct our C2M2 to compare results year over year.

SCE also leverages BitSight security ratings, which are similar to consumer credit scores, to address cyber risk on supply chain vendors. We also benchmark at a high level with other utilities to compare performance and spend. We will continue to use these metrics to inform our cybersecurity plans and strengthen our defense-in-depth capabilities to protect SCE from cyberthreats.

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Employee, Contractor, and Public Safety

Chapter 7

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

In this chapter SCE discusses actions we take to protect our employees and contractors ("workers"), and members of the public from safety risks that can result when a worker performs one of the following acts:

- Incorrectly executing work due to knowingly or unknowingly violating a procedure, policy, or rule;
- Failing to identify, correct, and/or account for hazardous conditions or work practices;
- Incorrectly operating a vehicle;
- Following incorrect processes or system designs;
- Not being fit for duty;
- Lacking necessary skills or qualifications.

The chapter analyzes incidents that occur in the field, in office environments, and in vehicles. The chapter distinguishes between field incidents that involve electrical assets (e.g. working with energized components) and those that do not involve electrical assets (e.g. falling from a ladder).

This chapter describes two compliance activities:[1]

- Safety Compliance (CM1 & CM2): These activities represent a substantial portion of SCE's safety efforts, addressing areas such as worker protection from falls, working in confined spaces, and safe work around electrical hazards. Work in these areas involves establishing company standards and programs, developing and implementing work practices, and developing and delivering training.

In addition to the compliance activities, this chapter describes two controls:[2]

- Safety Controls (C1): This includes programs related to recognition and injury assistance.

[1] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

[2] C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

- Contractor Safety Program (C2): This includes a range of activities related to establishing qualification requirements for contractors, continually evaluating contractor safety performance, and making field-based assessments and observations.

Finally, this chapter describes seven mitigations, including:[3]

- Safety Culture Transformation (M1a & M1b): SCE's strategic approach to improve the safety of our workers and the public; presented with two variations based on the type of training and the incorporation of electronic tablets.
- Industrial Ergonomics (M2): Program for ergonomics for industrial or field activities.
- Office Ergonomics (M3a & M3b): Enhancements to existing office ergonomics programs; presented with two variations of tools.
- Driver Safety (M4a & M4b): Driver assessment and training; presented with two variations based on the population targeted for the training.

SCE has developed three risk mitigation plans for consideration:

- The Proposed Plan builds on existing safety programs, while adding new efforts such as the Safety Culture Transformation Program and ergonomics programs.
- Alternative Plan #1 offers an expanded version of the Safety Culture Transformation Program in the Proposed Plan, while adding additional activities related to ergonomics and driver safety.
- Alternative Plan #2 strikes a middle ground between the Proposed Plan and Alternative Plan #1. Alternative Plan #2 offers the core programs proposed in the Proposed Plan, and adds a more limited version of the driver safety program featured in Alternative Plan #1.

[3] M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report, and are addressed in Section IV.

B. Scope

The scope of this Chapter is defined in Table I-1.

Table I-1 - Chapter Scope	
In Scope	• Acts performed by an SCE employee and/or contractor ("SCE worker") that lead to an adverse outcome for SCE workers or the public.
Out of Scope	• Vehicle incidents due to human error by a member of the public. • Criminal and/or malicious acts performed by SCE workers that harm the worker, other workers and/or the public.[4] • Public safety incidents occurring as a result of the public's unauthorized interactions with SCE's electric and/or non-electric assets. • Incidents that occur solely as a result of failed electrical and non-electrical assets and equipment.[5] • Acts that do not result in an adverse outcome. SCE does not track or maintain records of such acts, and cannot reasonably forecast the number of acts that SCE workers perform that do not result in an adverse outcome.[6]

[4] We evaluate workplace violence and insider threats in Chapter 6 - Cyber Attack and Chapter 9 - Physical Security.

[5] We examine the safety consequences associated with SCE assets failing in these chapters: Chapter 4 – Building Safety, Chapter 5 – Contact with Energized Equipment, Chapter 8 – Hydro Asset Safety, Chapter 10 – Wildfire, and Chapter 11 – Underground Equipment Failure.

[6] SCE monitors close calls—incidents in which an adverse outcome did not occur, but could have—and implements learnings from such incidents as appropriate.

C. Summary Results

Table I-2 summarizes this chapter's baseline risk analysis, controls and mitigations contemplated, and portfolio results over the 2018 – 2023 period.

Table I-2 – Summary Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Safety Controls	X	X	X
C2	Contractor Safety Program	X	X	X
M1a	Safety Culture Transformation – Core Program	X		X
M1b	Safety Culture Transformation – Expanded Training & Electronic Tailboards		X	
M2	Industrial Ergonomics	X	X	X
M3a	Office Ergonomics – Core Program	X	X	X
M3b	Office Ergonomics – Additional Software		X	
M4a	Driver Safety Training – Full Training Population		X	
M4b	Driver Safety Training – Limited Training Population			X
Mean (MARS)	*Cost Forecast ($ Million)*	$13.2	$15.1	$13.5
	Baseline Risk	6.98	6.98	6.98
	Risk Reduction (MRR)	0.53	0.59	0.54
	Residual Risk	6.45	6.39	6.44
	Risk Spend Efficiency (RSE)	0.040	0.039	0.040
Tail Average (MARS)	*Cost Forecast ($ Million)*	$13.2	$15.1	$13.5
	Baseline Risk	10.01	10.01	10.01
	Risk Reduction (MRR)	0.41	0.47	0.43
	Residual Risk	9.60	9.54	9.58
	Risk Spend Efficiency (RSE)	0.031	0.031	0.032

Figures represent 2018 - 2023 annual averages.

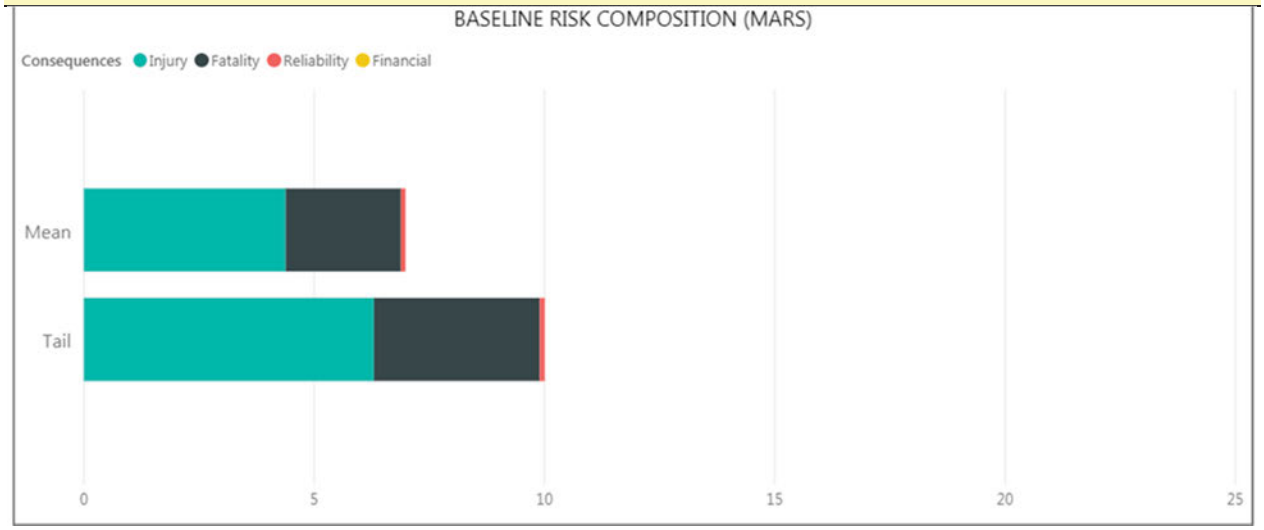
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 summarizes the baseline risk including compliance controls, prior to application of controls and mitigations, and depicts the composition of the consequences. The majority of this risk is related to safety consequences, with marginal impact to reliability.

Figure I-1 - Baseline Risk Composition (MARS)



Maximum MARS score is 100.

II. Risk Assessment

A. Background

The safety of our customers, the general public, and our workers is of utmost importance to SCE. The work that we perform to maintain our electric system is diverse, and includes activities such as:

- Installing and replacing transmission and distribution utility poles, towers, and electrical conductors;
- Managing vegetation on or around overhead equipment;
- Maintaining electrical assets at over 800 substations;
- Maintaining administrative and operational facilities that support grid operations;
- Using vehicles to transport workers, tools, and equipment to work sites; and,
- Performing office-related work activities.

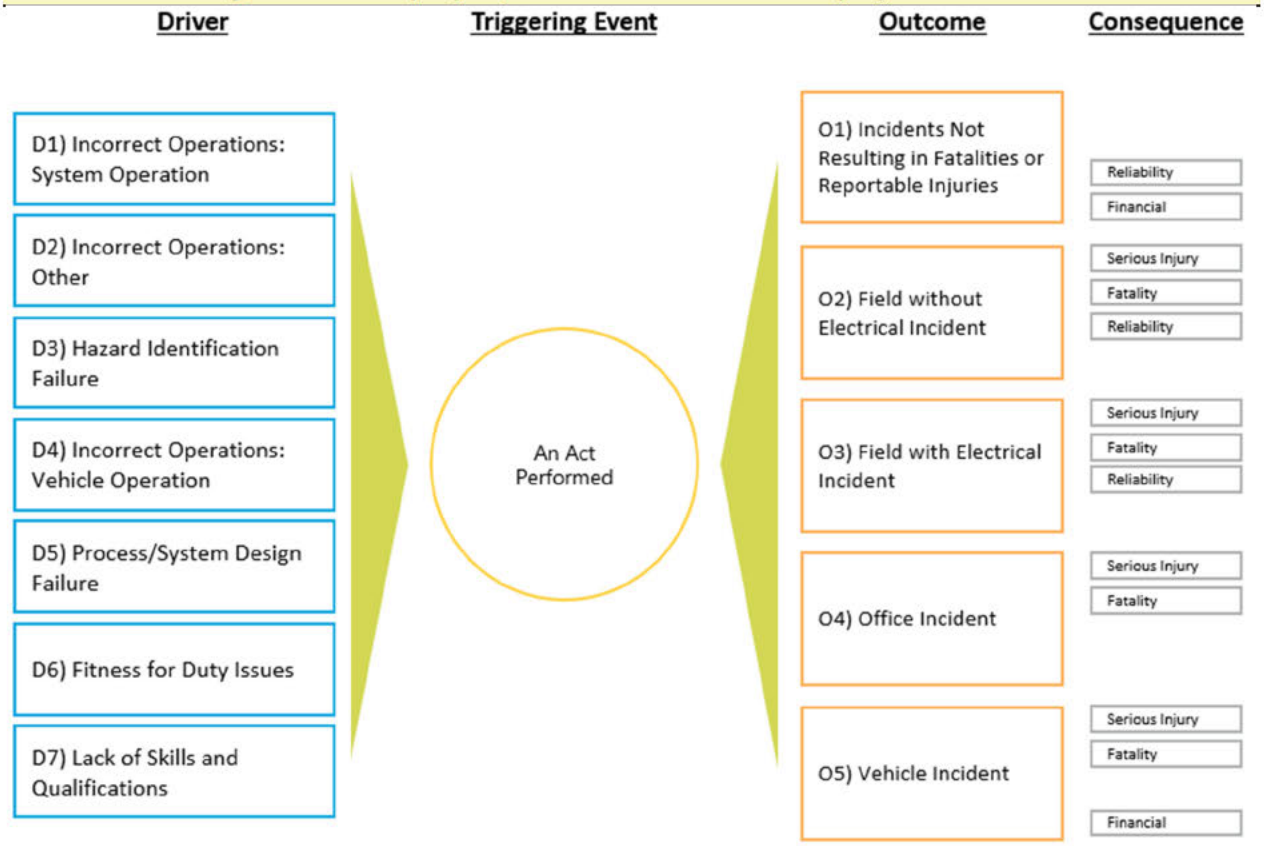
We perform these potentially hazardous tasks in order to provide safe, reliable, affordable, and clean electricity to our customers across a 50,000 square mile service territory.

The number of SCE employees and contractors is a key factor in the exposure that this risk presents. In 2017, SCE's workforce consisted of approximately 21,000 workers (counting both employees and contractors).[7] Approximately half are classified as field workers. SCE defines field workers as SCE employees or SCE-authorized contractors who perform more than 50% of their job responsibilities outside of the office environment, including working on or operating SCE's electrical system. SCE defines office workers as SCE employees or SCE-authorized contractors who perform more than 50% of their job responsibilities inside an office environment. Historically speaking, the majority of incidents that result in serious injuries or fatalities occur in the field.

SCE constructed a risk bowtie, as shown in Figure II-1, to evaluate this risk. Each component of the bowtie represents a critical data point in evaluating this risk.[8]

[7] The number of workers used is based upon actual SCE employee count, plus an estimated count of contract workers. That estimated count is derived from the number of contractor work hours recorded in 2017 (i.e., 2,000 contractor work hours was translated to represent 1 worker). It is difficult to capture total exposure to the public. Exposure is broader than our customer base, and includes any person within SCE's service territory with whom SCE workers come in contact.
[8] Please refer to WP Ch. 7, pp. 7.1 – 7.4 (*Baseline Risk Assessment*).

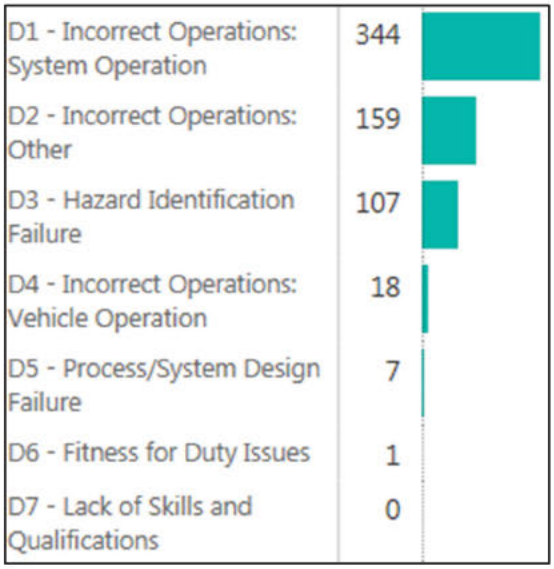
Figure II-1 – Employee, Contractor and Public Safety Risk Bowtie



B. Drivers

SCE identified seven primary drivers. These drivers and their annual frequencies are shown in Figure II-2.

Figure II-2 – 2018 Projected Driver Frequency



1. D1 – Incorrect Operations: System Operation

D1 represents acts performed due to a worker incorrectly executing field work that relates to operating the electrical system. In these events, a worker knowingly or unknowingly violates a procedure, policy, or rule. Examples include improper operation of switches on electrical equipment, or inappropriately energizing or de-energizing a transformer or other electrical equipment. These types of actions can cause an incident such as an arc flash, which could result in a serious injury.

SCE estimated an annual frequency of 344 for this driver based on analyzing historical outage occurrences that were associated with worker actions over the 2014-2017 time period.[9]

2. D2 – Incorrect Operations: Other

D2 represents acts performed due to a worker incorrectly executing work that does not pertain to electrical systems or vehicle operations. In these events, a worker knowingly or unknowingly violates a procedure, policy, or rule. Examples include incorrectly operating tools and equipment, lifting or carrying materials in a way that is ergonomically unsound, or falling from heights due to improper use of fall protection equipment.

SCE estimated an annual frequency of 159 for this driver based on analyzing historical employee and contractor incident and injury data over the 2014-2017 time period.

3. D3 – Hazard Identification Failure

D3 represents acts performed due to a worker failing to identify, correct, and/or account for hazardous conditions in the work environment or work practices. For example, hazardous conditions can include inadvertently positioning oneself in harm's way (e.g., standing beneath a suspended load).

SCE estimated an annual frequency of 107 for this driver based on analyzing historical employee and contractor OSHA data over the 2014-2017 time period.

4. D4 – Incorrect Operations: Vehicle Operation

D4 represents acts performed due to a worker's incorrect operation of a vehicle. In these events, a worker knowingly or unknowingly violates a procedure, policy, or rule.

SCE estimated an annual frequency of 18 for this driver based on analyzing historical employee and contractor incident and injury data over the 2014-2017 time period.

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[9] After every unplanned outage on the SCE distribution system, SCE staff reviews and verifies information on the number of customers affected by the outage, the duration of the outage, the cause of the outage, and the location of the outage. In addition, SCE staff reviews all outages with durations of twenty-four hours or more.

5. D5 – Process/System Design Failure

D5 represents acts performed due to a worker following incorrect processes or system designs. As work environments change and new technologies are used in the workplace, existing processes or system designs may no longer promote the safest work practices.

SCE estimated an annual frequency of 7 for this driver based on analyzing incident cause evaluation data over the 2014-2017 time period.

6. D6 – Fitness for Duty Issues

D6 represents acts performed while a worker is not fit for duty. Workers are expected to come to work fit for duty, meaning they cannot be under the influence of legal or illegal drugs, alcohol, or have physical or mental conditions that prevent them from accomplishing their job functions safely.

SCE estimated an annual frequency of 1 for this driver based on analyzing human resources data and incident cause evaluation data over the 2014-2017 time period. The relatively low frequency here is a reflection that the worker not being fit for duty must actually result in a qualifying triggering event.

7. D7 – Lack of Skills and Qualifications

D7 represents acts performed due to a worker's lack of necessary skills or qualifications. Skills and qualifications include physical and mental aptitude and knowledge gained through training.

SCE estimated an annual frequency of 0.5 for this driver based on analyzing incident cause evaluation data over the 2014-2017 time period. Again, the relatively low frequency is a reflection that the driver must actually result in a triggering event.

C. Triggering Event

The triggering event is defined as an act performed by an SCE worker that leads to an adverse outcome for an SCE employee, contractor, or a member of the public.

The triggering event frequency is composed of the estimated annual frequencies of D1 – D7. As shown in Figure II-3, SCE forecasts a flat growth rate for the drivers and triggering event frequency over the RAMP period. This forecast is based upon SCE's historical safety performance coupled with the observation that current controls on their own have already achieved their anticipated results in reducing incidents. Absent implementing planned mitigations, we would expect comparable safety performance in the foreseeable future.

Figure II-3 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	Total
Employee, Contractor and Public Safety							
Baseline	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**3,824.49**
Driver							
D1 - Incorrect Operations: System Operation	344.17	344.17	344.17	344.17	344.17	344.17	**2,065.03**
D2 - Incorrect Operations: Other	159.32	159.32	159.32	159.32	159.32	159.32	**955.95**
D3 - Hazard Identification Failure	106.56	106.56	106.56	106.56	106.56	106.56	**639.38**
D4 - Incorrect Operations: Vehicle Operation	18.49	18.49	18.49	18.49	18.49	18.49	**110.93**
D5 - Process/System Design Failure	7.38	7.38	7.38	7.38	7.38	7.38	**44.29**
D6 - Fitness for Duty Issues	0.99	0.99	0.99	0.99	0.99	0.99	**5.95**
D7 - Lack of Skills and Qualifications	0.49	0.49	0.49	0.49	0.49	0.49	**2.96**
Total	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**637.41**	**3,824.49**

D. Outcomes

SCE has identified five outcomes, which are described in greater detail below. Figure II-4 indicates the relative likelihood of each outcome should the triggering event occur.

Figure II-4 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Incidents Not Resulting in Fatalities or Reportable Injuries	97.5 %	
O2 - Field without Electrical Incident	1.6 %	
O3 - Field with Electrical Incident	0.8 %	
O4 - Office Incident	0.1 %	
O5 - Vehicle Incident	0.0 %	

Figure II-5 illustrates the composition of the modeled baseline risk in terms of each consequence. The majority of serious injuries and fatalities occur through O2 (Field without Electrical Incident) and O3 (Field with Electrical Incident). In addition, the vast majority of the reliability and financial impacts for this risk occur through O1 (Incidents Not Resulting in Fatalities or Reportable Injuries). The sections that follow detail the inputs used to derive these results.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (Natural Units)

As noted in Chapter I (RAMP Overview), SCE evaluated several potential criteria that could define the serious injury threshold for purposes of this RAMP Report. SCE selected the serious injury definition from the Edison Electric Institute (EEI). While SCE is moving toward the EEI standard for classifying and analyzing internal injury data, the historical data available for this chapter did not always use the EEI criteria in classifying serious and non-serious injuries. For example, SCE's historical safety data from contractors is typically based on classifying an injury as serious if the injury must be reported to the California Division of Occupational Safety and Health (also known as Cal/OSHA).

As explained below, in most cases this chapter used historical data on Cal/OSHA reportable injuries as a proxy for estimating serious injuries on a forward-looking basis under the RAMP framework.

1. O1 – Incidents Not Resulting in Fatalities or Reportable Injuries

This outcome captures incidents in which an injury may have occurred, but the injury did not meet the threshold for reporting to Cal/OSHA. For example, if an incident in the field, in the office, or in a vehicle did not result in a Cal/OSHA reportable injury or fatality, it is included in this outcome. However, if an incident resulted in a Cal/OSHA reportable injury, it would be included in one of the other outcomes (O2 – O5).

This outcome does not include incidents in which a fatality occurred (these incidents would be included in one of the outcomes described below).

Because this outcome excludes fatalities and incidents with injuries that were serious enough to be reported to Cal/OHSA, it is only modeled in terms of the reliability and financial consequences. However, we wish to emphasize that SCE's safety approach is oriented toward reducing all injuries, not just the relatively rare incidents that result in serious injuries.

Potential consequences from O1 are summarized on an annualized basis in Table II-1. Reliability impacts are associated with service interruptions caused by worker error during field incidents. Financial costs are associated with damage due to vehicle incidents. For O1, the estimate of annual impacts is 7.6M customer minutes of interruption (CMI) and $24K of financial harm on a mean basis; and 8.4M CMI and $26K of financial harm on a tail-average basis.

Table II-1 – Outcome 1 (Incidents Not Resulting in Fatalities or Reportable Injuries): Consequence Details

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			Outage impacts associated with worker errors, SCE internal database for years 2014-2017.	Available data was limited to property damage related to vehicle incidents in scope for this outcome for years 2014-2016.
Model Outputs	NU - Mean			7.6M (CMI)	$24K
	NU - Tail Avg			8.4M (CMI)	$26K

NU = Natural Unit

2. O2 – Field without Electrical Incident

This outcome includes incidents involving field workers that do not directly involve SCE electrical assets. Examples include, but are not limited to, an employee fracturing his/her ribs after falling from a ladder, or an employee suffering from heat exhaustion.

Potential consequences from O2 are summarized on an annualized basis in Table II-2. Serious injuries and fatalities are associated with the harm that was caused by the incident. Reliability impacts are associated with service interruptions caused by worker error. For O2, the estimate of annual impacts is 9.51 serious injuries, 0.50 fatalities, and 231K customer minutes of interruption (CMI) on a mean basis; and 17.87 serious injuries, 0.94 fatalities, and 435K customer minutes of interruption (CMI) on a tail-average basis.

Table II-2 – Outcome 2 (Field without Electrical Incident): Consequence Details

Outcome 2		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*	Injuries reported to Cal/OSHA for years 2014-2017.	Fatalities tracked internally by SCE and reported to SCE by SCE contractors for years 2014-2017.	Outage impacts associated with worker errors, SCE internal database for years 2014-2017.	
Model Outputs	NU - Mean	9.51	0.50	231K (CMI)	
	NU - Tail Avg	17.87	0.94	435K (CMI)	

3. O3 – Field with Electrical Incident

This outcome includes incidents involving field workers and SCE electrical assets. Examples include arc flash burns from opening a 12 kV line disconnect in the wrong position, or making contact with energized components while working in an underground structure.

Potential consequences from O3 are summarized on an annualized basis in Table II-3. Serious injuries and fatalities are associated with the harm that was caused by the incident. Reliability impacts are associated with service interruptions caused by worker error. For O3, the estimate of annual impacts is 5.25 serious injuries, 0.50 fatalities, and 121K customer minutes of interruption (CMI) on a mean basis; and 10.39 serious injuries, 1.13 fatalities, and 275K customer minutes of interruption (CMI) on a tail-average basis.

Table II-3 – Outcome 3 (Field with Electrical Incident): Consequence Details

Outcome 3		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*	Injuries reported to Cal/OSHA for years 2014-2017.	Fatalities tracked internally by SCE and reported to SCE by SCE contractors for years 2014-2017.	Outage impacts associated with worker errors, SCE internal database for years 2014-2017.	
Model Outputs	NU - Mean	5.25	0.50	121K (CMI)	
	NU - Tail Avg	10.39	1.13	275K (CMI)	

4. O4 – Office Incident

This outcome includes incidents involving office workers. Examples include a worker slipping and falling while walking and fracturing a bone, or another worker dislocating a joint while walking.

Potential consequences from O4 are summarized on an annualized basis in Table II-4. Serious injuries and fatalities are associated with the harm that was caused by the incident.

For O4, the estimate of annual impacts is 0.36 serious injuries and nearly 0 fatalities on a mean basis; and 1.41 serious injuries and nearly 0 fatalities on a tail-average basis.

Table II-4 – Outcome 4 (Office Incident): Consequence Details

Outcome 4		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	Injuries tracked by SCE that met the EEI definition for years 2014-2017. This criteria was used due to a lack of Cal/OSHA reported incidents during 2014-2017.	Fatalities tracked internally by SCE and reported to SCE by SCE contractors for years 2014-2017.		
Model Outputs	NU - Mean	0.36	0.00		
	NU - Tail Avg	1.41	0.00		

5. O5 – Vehicle Incident

This outcome includes vehicle incidents associated with SCE workers. Examples include a worker striking a streetlight while driving an SCE vehicle, or rear-ending another vehicle. This outcome excludes incidents that occurred outside of the course and/or scope of employment.

Potential consequences from O5 (Vehicle Incident) are summarized on an annualized basis in Table II-5. Serious injuries and fatalities are associated with the harm that was caused by the incident. Financial costs are associated with property damage. For O5, the estimate of annual impacts is 0.25 serious injuries, nearly 0 fatalities, and $0.3K of financial harm on a mean basis; and 2.04 serious injuries, nearly 0 fatalities, and $2.8K of financial harm on a tail-average basis.

Table II-5 – Outcome 5 (Vehicle Incident): Consequence Details

Outcome 5		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	Injuries reported to Cal/OSHA for years 2014-2017.	Fatalities tracked internally by SCE and reported to SCE by SCE contractors for years 2014-2017.		Property damage related to vehicle incidents for years 2014-2016.
Model Outputs	NU - Mean	0.25	0.00		$0.3K
	NU - Tail Avg	2.04	0.00		$2.8K

III. Compliance & Controls

Table III-1 maps controls to drivers, outcomes, and consequences, in addition to showing 2017 recorded costs for both compliance activities and controls.

Table III-1 – Inventory of Compliance & Controls[10]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Costs ($M)	
					Capital	O&M
CM1	Safety Compliance – Standards, Programs & Policies	Not Modeled	Not Modeled	Not Modeled	$0	$11.20
CM2	Safety Compliance – Technical Training	Not Modeled	Not Modeled	Not Modeled	$0	$57.50
C1	Safety Controls	All	-	-	$0	$0.30
C2	Contractor Safety Program	All	-	-	$0	$0.16

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

A. CM1 – Safety Compliance – Standards, Programs & Policies

Title 8 of the California Code of Regulations and Title 29 of the Code of Federal Regulations require that employers maintain safety standards, programs, and policies for the welfare of their employees. Consequently, SCE maintains a number of safety standards, programs and policies. Some examples are listed below:[11]

- Bloodborne Pathogens Exposure Control Standard
- Chemical Management
- Confined Space Program
- Fall Protection Standard
- Hazardous Energy Control
- Hearing Conservation Program
- Heat Illness Prevention Program
- Hot Work Program[12]
- Injury and Illness Prevention Program
- Respiratory Protection Program

[10] Please refer to WP Ch. 7, pp. 7.5 – 7.18 (*RAMP Mitigation Reduction Workpaper*).
[11] Please refer to WP Ch. 7, pp. 7.20 – 7.21 (*Safety Standards, Programs, and Policies*).
[12] Hot work activities include soldering, welding, pipe-cutting, heat-treating, grinding, thawing pipes, hot riveting, torch-applied roofing and any other application involving heat, sparks or flames.

- Safety Incident Management Standard

These requirements and processes are designed to mitigate risk to workers when followed. On a routine basis, SCE reviews its standards, programs and policies to help ensure they are accurate, effective and up-to-date.

B. CM2 – Safety Compliance – Technical Training

This compliance activity focuses primarily on providing training to employees working in the field. Similar to CM1 (Safety Compliance – Standards, Programs & Policies), SCE is required to perform these activities according to Title 8 of the California Code of Regulations and Title 29 of the Code of Federal Regulations, as well as function-specific regulations according to Department of Transportation and Federal Aviation Administration.

Examples of these programs include: Distribution Apprentice Lineman Program, Transmission Groundman and Apprentice Lineman Programs, Distribution Groundman and Lineman Training Programs, Lineman & Electric-Crew Foreman Skills Refresher, Troubleman Skills and Knowledge Training, Transmission Skills, Apparatus Technician, Construction Field Forces (CFF) Electrician, CFF Battery Electrician, and Transmission Estimator.

C. C1 – Safety Controls

SCE maintains safety programs above and beyond federal and state regulations. These programs include the Safety Recognition Program, Injury Assistance Program, and Functional Movement Screening.

The Safety Recognition Program provides a forum to recognize our employees for their commitment to working safely. It enables formal and informal recognition by both managers and employees for various safety behaviors through online thank-you cards and awards.

SCE implemented the Injury Assistance Program (IAP) in August 2014. The IAP is an injury assistance hotline to provide access to trained medical professionals (nurses and/or physicians). These medical professionals can assess non-emergency medical situations over the telephone, and provide care advice. The IAP hotline guides the employee through self-care options (when appropriate), or directs the employee to the nearest available clinic within the SCE Medical Provider Network, and expedites paperwork for quicker appointments. This program is voluntary and can help prevent minor injuries from potentially becoming more serious.

SCE provides the Function Movement Screening (FMS) for T&D field employees. FMS uses a customized stretching and muscle-stabilizing sequence prescribed for each participating employee. FMS improves the physical performance of the employee, assisting them with the

basic movement functions of their job. Quarterly assessments of participants provide individual results and facilitate sustainability of the exercise program.

1. Drivers Impacted

The Safety Recognition Program reduces all drivers, as it reinforces positive behaviors and safe work practices. Notably, FMS reduces driver frequency for D2 (Incorrect Operations: System Operations) and D3 (Hazard Identification Failure) by providing customized assessments for individuals to perform work safely with an improved understanding of their physical abilities.

2. Outcomes and Consequences Impacted

The primary focus of this control is to reduce the drivers of this risk. While there are benefits associated with reducing the severity of minor injuries (e.g. strains, sprains, soft-tissue injuries, etc.), we do not model those benefits in this RAMP as we are only capturing safety consequences related to serious injuries and fatalities.

D. C2 – Contractor Safety Program

This control focuses on the work SCE performs to improve the safety of our contractors. In 2017, SCE reached a Settlement Agreement[13] with the CPUC regarding several contractor safety practices.[14] As SCE is obligated to adhere to the Settlement, it represents a compliance obligation. Because this is SCE's primary program related to contractor safety, and because the Settlement was enacted recently, SCE determined that it was more appropriate to treat these activities as a control. This allows the contractor safety program to be included in the analytical modeling and to be measured in terms of its impact on drivers and/or outcomes.

Key aspects of the program are summarized in Table III-2.

[13] D.17-06-028. Decision Adopting the Settlement Agreement re Investigation 15-11-006, Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Edison Company (U338E); Notice of Opportunity for Hearing; and Order to Show Cause Why the Commission Should not Impose Fines and Sanctions for the September 30, 2013 Incident at a Huntington Beach Underground Vault.
[14] SCE had been performing contractor safety activities in various capacities prior the Settlement Agreement.

Table III-2 – Key Elements of Contractor Safety Program

Retention of a Third Party Administrator	Review and qualify contractors identified as performing higher-risk activities.
Expanded Criteria for Contractor and Subcontractor Qualification	Additional criteria for an entity to become qualified to contract with SCE, such as Occupational Safety and Health Administration (OSHA) citation history, fatality history, and significant public safety events.
Enhanced Field Safety Observations	SCE contractor liaisons conduct regular field safety observations.
Hazard Assessment and Environmental, Health, and Safety Plans	Identifying health and safety issues and verifying that contractors have strong hazard mitigation plans in place.
Quality Assurance Reviews	Detailed on-site assessments of selected high-risk contractors to validate the implementation of written contractual safety commitments.

In addition to the above elements, SCE is also engaging with contractor company leaders to leverage core tenets of safety culture transformation efforts occurring at SCE.

3. Drivers Impacted

All drivers are impacted by this mitigation. Improved processes and controls related to contractor qualification and performance are expected to reduce driver frequencies.

4. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this control.

IV. Mitigations

Beyond the compliance and control activities discussed above, SCE has identified potential new ways to further mitigate this risk. These activities are summarized in Table IV-1, and discussed in more detail below.

Table IV-1 – Inventory of Mitigations[15]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan			RAMP Implementation	
					Proposed	Alt. #1	Alt. #2	Start	End
M1a	Safety Culture Transformation – Core Program	All	-	-	x		x	2018	2021
M1b	Safety Culture Transformation – Expanded Training & Electronic Tailboards	All	-	-		x		2018	2023
M2	Industrial Ergonomics	D2, D3, D5, D7	-	-	x	x	x	2018	2023
M3a	Office Ergonomics – Core Program	D3, D5, D7	-	-	x	x	x	2018	2023
M3b	Office Ergonomics – Additional Software	D3, D5, D7	-	-		x		2018	2023
M4a	Driver Safety Training – Full Training Population	D3, D4, D7	O5	S-I		x		2018	2023
M4b	Driver Safety Training – Limited Training Population	D3, D4, D7	O5	S-I			x	2018	2023

Consequence abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial – F

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report, and are addressed in Section IV.

A. M1a – Safety Culture Transformation – Core Program

SCE implemented the Safety Culture Transformation program in 2018 after completing design and planning work in 2017. While this mitigation is currently scoped to implement through 2021, SCE plans to continually assess our progress, and will augment this approach as necessary to achieve the desired safety culture and associated injury reduction.

M1a (Safety Culture Transformation – Core Program) represents a strategic approach to improving the safety of our workers and the public. This mitigation provides changes needed to improve our safety performance through an improved safety culture. These efforts will focus primarily on SCE employees.

M1a is composed of six focus areas that are represented in Table IV-2 and described in more detail below.

[15] Please refer to WP Ch. 7, pp. 7.5 – 7.18 (*RAMP Mitigation Reduction Workpaper*).

Table IV-2 – Six Focus Areas of Safety Culture Transformation Program

#	Focus Area	Objective
1	Common Understanding of Safety Culture Change	Build a common understanding and vision for our future-state safety culture.
2	Leadership and Talent Management	Implement safety culture training and safety leadership assessments, and incorporate safety into the hiring process.
3	Safety Communications	Align and improve safety communications, processes, and messaging across the company.
4	Hazard Awareness and Risk Management	Provide and enhance tools to improve the ability of employees to identify hazards and make safe decisions for how to proceed.
5	Safety Data Strategy	Improve integrity and integration of safety-related data across the company to enable data-driven insights.
6	Safety Structure, Governance, and Programs	Build foundation for successful safety culture change through organizational structures, safety governance, and refinement of existing safety programs to align with our safety culture vision.

1. Common Understanding of Safety Culture Change

This focus area provides the organization with context for the importance of safety culture change and the means to achieve this change. These efforts began with communications with employees to share the results of our 2017 Safety Culture Assessment,[16] which identified areas for improvement and established a common understanding of where SCE stands today and needs to go in the future.

Next, SCE senior leadership defined the company's future state safety culture; this guides the tone of safety communications, the development of safety training, the enhancement of tools and processes to identify and mitigate risks, and the evolution of safety programs discussed in the following sections.

2. Leadership and Talent Management

The Leadership and Talent Management focus areas addresses three main activities: (a) Training, (b) Assessment for New Leaders & Hiring Practices.

a. Training

Under M1a (Safety Culture Transformation – Core Program), SCE employees will participate in a new safety culture training with three components called *Switch, Engage,*

[16] SCE's 2017 Safety Culture Assessment was conducted to understand the current state of SCE's safety culture and identify areas for reinforcement as well as opportunities for improvement.

and *Connect*. This training provides cognitive-based tools to enable participants to make safer choices by obtaining a deeper understanding of thought processes.

SCE has begun implementing these trainings with field employees, since high-hazard job classifications generally involve higher safety risk. Field employees will experience *Switch* through a two-day, in-person training class.

After attending *Switch,* field leaders will attend *Engage,* a two-day, in-person leadership workshop that provides practical tools for implementing *Switch* concepts, supporting a strong safety culture, and influencing safety behaviors. Three months later, these leaders will meet a third time for a one-day, in-person *Connect* training, which will focus on leading effective teams and creating an environment where safety is physically and psychologically valued.

In 2019, SCE will begin *Switch, Engage* and *Connect* training with the rest of the company. To manage costs and to accelerate adoption, SCE is utilizing a blended roll-out approach for enterprise implementation. This approach proposes initial computer-based training to cover basic *Switch* and *Engage* introductory concepts. The computer-based training will be followed by one-day, in-person classes with activities and discussion of the cognitive-based tools and techniques. *Connect* will be in-person.

b. Assessment for New Leaders & Hiring Practices

The words and actions of leaders can significantly influence the safety choices made by their teams. This component of M1a will roll out a leadership profile assessment to facilitate hiring new leaders who demonstrate the personal attributes necessary to create a safe, supportive, and inclusive work environment. This assessment will be implemented for new leaders, beginning with field functions, and then expanded to the entire enterprise.

This effort also aims to align talent pipeline processes, such as recruiting and selecting candidates, with core safety competencies and values. It implements a more targeted approach to finding and selecting job talent that will align with our evolving safety culture.

3. Safety Communications

Here, we aim to redesign the safety communications structure, processes, and messaging approach so that communications resonate with employees and promote individual ownership of safety.

SCE's 2017 Safety Culture Assessment noted that there is a lot of "noise" around safety. For example, the volume of safety awareness campaigns deployed at the enterprise, organizational, and grassroots levels has led to numerous safety messages. The variation in safety messaging has caused confusion and diluted the impact of safety communications.

We have developed a consistent, enterprise-wide safety communications strategy and voice using the "Own It" theme (i.e., encouraging employees to "own" their personal safety). SCE has, and will continue to, reduce and refine the number of safety-related communications and emails to focus on quality and consistency over quantity.

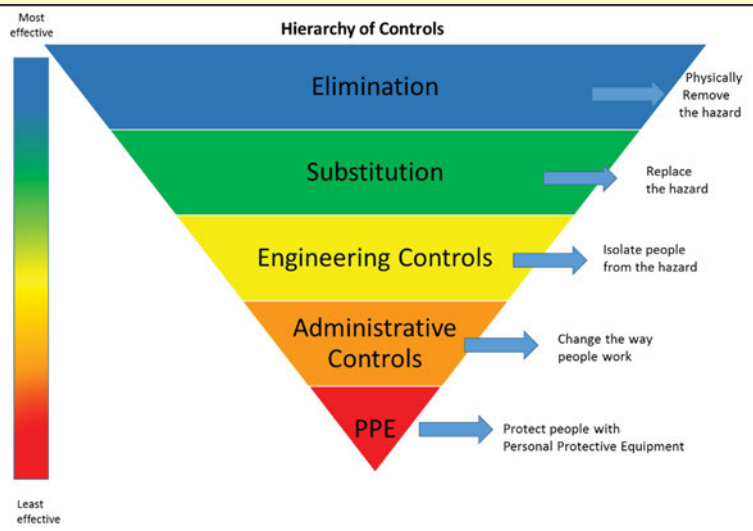
4. Hazard Awareness and Risk Management

This focus area will provide four tools (job hazard analysis, hierarchy of controls, error prevention tools, and tailboards) to improve the ability of employees to identify hazards in the workplace and make safe decisions on how to proceed.

A Job Hazard Analysis (JHA) is a tool used by field employees to identify the hazards associated with performing specific job tasks. It provides actions to reduce the risk of injury before any injury occurs. As part of M1a (Safety Culture Transformation – Core Program), JHAs were created for tasks with high incident or injury rates, as well as those that have potential to cause serious injury.

The Hierarchy of Controls (shown below in Figure IV-1) provides a systematic approach to manage hazards and make safe decisions. Implementing the hierarchy of controls when planning, designing, and performing work guides us in considering controls that range from more effective (removing the hazard) to, in relative terms, less effective (i.e. PPE, which can protect a worker in case of an incident, but does not prevent the incident from occurring in the first place).[17] Put simply, this hierarchy helps reduce the risk of serious injury or fatality by making sure that we utilize the most effective controls first and more frequently.

Figure IV-1 – Hierarchy of Controls



[17] SCE is not suggesting that it is unimportant for front-line workers to wear PPE, or that rules and practices concerning PPE should not be followed.

SCE is expanding the use of error prevention tools and the understanding of human performance principles for all field employees. Human performance principles are based on understanding people and human nature, then finding ways to reduce their chances of making a mistake.[18] This effort will standardize the definition of, and training on, error prevention tools; this should reduce the chance that an incident or injury occurs while employees perform their work.

SCE has utilized tailboards, or pre-job briefings, for many years through structured forms that outline the work to be performed, the processes to be followed, and the potential safety hazards. However, the 2017 Safety Culture Assessment found that SCE's current tailboard process generally leads to a presentation format rather than a group discussion. The revised tailboard will provide the environment necessary to engage in group dialogue, which includes every participant giving input. We believe that by facilitating discussion, we will see greater engagement and greater identification and mitigation of hazards.

5. Safety Data Strategy

SCE does not currently have an integrated and comprehensive safety data architecture. For example, one system captures incidents impacting system reliability, while another system tracks employee safety incidents. This component of M1a (Safety Culture Transformation – Core Program) will develop and implement a comprehensive safety data architecture,[19] an integrated incident management system, a methodology for incident cause evaluations to improve the scope and quality of captured data, and capabilities in areas such as predictive analysis. With mechanisms in place to better collect, analyze and report data, SCE will increase its ability to identify major contributing factors that lead to incidents and close calls.

6. Safety Structure, Governance and Programs

This component of M1a (Safety Culture Transformation – Core Program) focuses on building the foundation for successful safety culture change through organizational structures, safety governance, and refinement of existing safety programs to align with our safety culture vision.

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[18] Three-way communication is an error prevention tool that provides mutual understanding and an opportunity to correct before an action is taken. For example, Worker A says, "I will be disconnecting position 1." Worker B responds, "Understood, you'll be disconnecting position 1." Worker A confirms, "Disconnecting position 1."

[19] This data architecture will align or integrate safety-related data, allowing communication and integration between various data systems.

a. Structure & Governance

As discussed in Chapter III (Safety Culture and Compensation Policies Tied to Safety), SCE has centralized our safety organizations into a single "Edison Safety" organization to allow for better company-wide alignment in our approach to creating a safe workplace. This component of M1a (Safety Culture Transformation – Core Program) will also focus on creating better alignment and communication amongst SCE's safety governance bodies, including the Executive and Senior Safety Councils, and OU Safety Councils.

b. Programs

The safety programs addressed here include the Craft Driven Safety Program, Safety Observation Program, and Safety Recognition Program.

1) Craft Driven Safety Program

This program was created in 2012 to improve safe work practices and enhance overall safety among field workers. This was a joint effort between SCE and IBEW Local 47 that implemented a peer-based safety performance management process. M1a will seek to improve this program by amplifying the transparency of safety-related incidents and communication of lessons learned.

2) Safety Observation Program

SCE's Safety Observation Program enables both manager-to-employee and peer-to-peer safety observations. A safety observation is the action of an individual observing the work of another individual in order to identify recommendations related to safe work performance (either positive or constructive). For example, an employee might submit an observation to recognize a peer for performing safe lifting practices, or an employee might submit an observation indicating that work was stopped at a field site due to the presence of unexpected hazardous conditions.

The data collected from safety observations is now available to all employees in the form of a dashboard, and supervisors are encouraged to utilize trends to take actionable steps to prevent future incidents.[20]

3) Safety Recognition Program

This component builds on the Safety Recognition Program described in C1 (Safety Controls), by rewarding employees who have displayed a continual pattern of safe behaviors and demonstrated that they personally value safety.

[20] For example, if a negative trend in hand injuries is identified, a leader can reinforce work practices that mitigate risk during tailboards and can focus observations on hand protection.

7. Drivers Impacted

M1a will impact all drivers.

- D1 (Incorrect Operations: System), D2 (Incorrect Operations: Other) and D4 (Incorrect Operations: Vehicle): These drivers will be reduced through cognitive-based skills obtained in *Switch* training, effective sharing of lessons learned, use of hazard awareness and error prevention tools, availability of trends and predictive analytics to drive decision-making, and consistent leader reinforcement of safety behaviors, values and attitudes.
- D3 (Hazard Identification Failure): This driver will be reduced through cognitive-based skills obtained in *Switch* training, use of hazard awareness and error prevention tools, effective sharing of lessons learned, and consistent leader reinforcement of safety behaviors, values and attitudes.
- D5 (Process/System Design Failure): This driver will be reduced through a more efficient and aligned safety organizational model, predictive analytics to drive proactive measures, and industrial ergonomics technology to make data-driven decisions and improvements.
- D6 (Fitness for Duty Issues): This driver will be reduced as personal safety ownership is adopted and safety behaviors evolve.
- D7 (Lack of Skills and Qualifications): This driver will be reduced through skills obtained in *Switch, Engage* and *Connect* trainings, identifying leadership skills through profile assessments, and identifying and hiring top talent aligned with our safety culture.

8. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation. While some aspects of this mitigation (e.g., emphasizing PPE rather than leveraging the hierarchy of controls) may influence outcomes, we did not model these potential benefits, as such indirect impacts are likely not material to this program's primary benefits.

B. M1b – Safety Culture Transformation – Expanded Training & Electronic Tailboards

This mitigation, which is included in Alternative Plan #1, implements the same scope of work as M1a (Safety Culture Transformation – Core Program), but delivers two-day, in-person safety training to all employees, and supplies electronic tablets to field supervisors enabling easy access to hazard awareness tools.

Providing two-day, in-person safety training to all employees, rather than blending e-learning and in-person training for non-T&D employees, allows more time for interactive discussion with facilitators and peers.

Purchasing electronic tablets for field supervisors builds on the tools and processes discussed in M1a. This technology could enhance adoption and availability of hazard awareness tools, as critical documentation such as procedures, manuals, and job hazard analyses will be instantly available through apps at any given time to supervisors and crews anywhere in our service territory.

Most SCE field supervisors currently have Toughbook laptops that they can use for basic functions. Tablets have the potential to supplement the Toughbook by providing additional functionality and information access through apps. While promising, at this time more evaluation is needed for SCE to determine the appropriate extent and scope of integrating tablets into field work activities.

1. Drivers Impacted

Because this implements the same general functionality as M1a, it will impact the same drivers as M1a.

2. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation.

C. M2 – Industrial Ergonomics

This mitigation enhances existing industrial ergonomics programs. Historically, SCE's industrial ergonomics efforts have emphasized injury prevention exercises as a primary hazard control (such as the FMS mentioned in C1 (Safety Controls)), and relied on dedicated field safety specialists to provide ergonomic guidance and employee coaching.

SCE is transitioning to a broader approach for industrial ergonomics, called *Set Up. Perform. Recover.*, which emphasizes three universal phases of work, regardless of the specific work environment. Key aspects of this industrial ergonomics program include:

- Physical Demands Analysis Evaluation: a process for examining postures, body movements, force, and duration.
- Wearable Technology: utilizing technology-embedded clothing that gives feedback, through computer-based systems, on muscle engagement and potential for overexertion injuries when performing certain work tasks.

1. Drivers Impacted

The adoption of the *Set Up. Perform. Recover*. approach by employees will reduce the frequency of D2 (Incorrect Operations: Other) and D3 (Hazard Identification Failure) as they

relate to industrial ergonomics practices. Through workshops and training, employee knowledge of ergonomic risk factors will improve and the frequency of D7 (Lack of Skills and Qualifications) will be reduced. Wearable technology will provide data to inform specific solutions that should reduce the frequency of D5 (Process/System Design Failure).

2. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation.

D. M3a – Office Ergonomics – Core Program

This mitigation enhances existing office ergonomics programs and builds on the *Set Up. Perform. Recover.* concept mentioned in M2 (Industrial Ergonomics). In the office environment, this approach focuses on employee behaviors when interacting with equipment.

Each new office workstation will include a sit-to-stand desk, giving employees the flexibility to change their set-up to fit their ergonomic needs.

1. Drivers Impacted

Self-assessments and ergonomic training will improve employee knowledge of ergonomic risk factors and increase skills around ergonomic hazard identification, which should mitigate strain and sprain risks. Thus, D3 (Hazard Identification Failure) and D7 (Lack of Skills and Qualification) frequencies will be reduced. Sit-to-stand desks will reduce the frequency of D5 (Process/System Design Failure) by enabling employees to adjust their own workstations to their ergonomic needs.

2. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation.

E. M3b – Office Ergonomics – Additional Software

This mitigation, which is included in Alternative Plan #1, provides employees with predictive data on how well they manage computer interactions such as keystrokes, mouse clicks, and regular breaks. The data collected through the software will also benefit SCE's ergonomics program managers by identifying at-risk groups for early intervention and injury prevention, and enabling future program elements to be tailored for maximum effectiveness.

1. Drivers Impacted

Drivers D3 (Hazard Identification Failure), D5 (Process/System Design Failure), and D7 (Lack of Skills and Qualification) will be impacted by this mitigation. This software will complement the overall ergonomics program by providing individual data and trends, reducing the frequency of D3 and D7. At both the individual and aggregate levels, this data and these

trends will enable proactive improvements in processes, communications and behaviors, reducing the frequency of D5.

2. Outcomes and Consequences Impacted

None of the outcomes or consequences are directly impacted by this mitigation.

F. M4a – Driver Safety – Full Training Population

This mitigation, which is included in Alternative Plan #1, would implement a training program for the approximately 4,200 SCE workers who are Class A license holders[21] or who are assigned to SCE vehicles.

1. Drivers Impacted

Drivers D3 (Hazard Identification Failure), D4 (Incorrect Operations: Vehicle), and D7 (Lack of Skills and Qualification) are impacted by this mitigation, as the training is expected to improve driving skills, abilities, and hazard avoidance.

2. Outcomes and Consequences Impacted

Serious Injury consequence of O5 (Vehicle Incident) will be impacted by this mitigation, as the training focuses on driving and vehicle safety, which improves a driver's ability to respond safely should an incident occur.

G. M4b – Driver Safety – Limited Training Population

This mitigation is identical to M4a (Driver Safety – Full Training Population), except the training population would be limited to the approximately 3,900 Class A license holders, in order to better implement and evaluate the training prior to introducing it to a larger population.

1. Drivers Impacted

SCE expects this mitigation to have the same impact at M4a on an individual basis, but its cumulative impact to this risk will be slightly lower due to being applied to a smaller training population.

2. Outcomes and Consequences Impacted

SCE expects this mitigation to have the same impact at M4a on an individual basis, but its cumulative impact to this risk will be slightly lower due to being applied to a smaller training population.

[21] The Class A license is for commercial vehicles with a Gross Vehicle Weight Rating of more than 10,000 pounds.

V. Proposed Plan

SCE has developed a Proposed Plan to mitigate this risk, as shown in Figure V-1 below.

Figure V-1 – Proposed Plan (2018 – 2023 Total Costs and Risk Reduction)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Safety Controls	2018	2023	$ -	$ 14.1	0.43	0.030	0.33	0.024
C2	Contractor Safety Program	2018	2023	$ -	$ 1.1	0.42	0.384	0.33	0.300
M1a	Safety Culture Transformation – Core Program	2018	2021	$ 13.0	$ 33.5	2.06	0.044	1.61	0.035
M2	Industrial Ergonomics	2018	2023	$ -	$ 0.1	0.07	0.769	0.05	0.600
M3a	Office Ergonomics – Core Program	2018	2023	$ 14.6	$ 3.0	0.21	0.012	0.16	0.009
			Total - Proposed Plan	**$ 27.6**	**$ 51.8**	**3.18**	**0.040**	**2.48**	**0.031**

MARS = Multi-Attribute Risk Score
MRR = Mitigated Risk Reduction
RSE = Risk Spend Efficiency

A. Overview

This plan reduces safety risk by implementing programs that are designed to shift the safety attitudes and behaviors of the entire organization. In addition to continuing SCE's existing safety controls, this plan implements the safety culture transformation program and ergonomics programs for industrial and office roles.

B. Execution feasibility

SCE believes that the Proposed Plan is feasible. SCE has the ability to continue the existing efforts within this plan, and the new activities build on existing capabilities and can be informed by historical experience. For example, the training in the safety culture transformation mitigation (M1a) covers a new training subject, but we have experience in the associated work and logistics. As described above, SCE has implemented this training program in 2018, and so far has not experienced issues with execution.

C. Affordability

The Proposed Plan costs $10.9M less than Alternative Plan #1, and $1.7M less than Alternative Plan #2. The RSE of the Proposed Plan (0.040) is higher than Alternative Plan #1 (0.039) and is the same as Alternative Plan #2 (0.040) on a mean basis.

The combination of existing and enhanced activities in the Proposed Plan represents a balance of reducing safety risks at prudent cost.

D. Other Considerations

The pace of organizational and programmatic changes in the safety areas has created a sense of "change fatigue" among SCE workers. SCE developed the Proposed Plan with this in mind. The safety culture transformation effort is intended to address this fatigue by

establishing a stable foundation for future safety efforts. However, SCE appreciates that the sentiment of “change fatigue” may affect the effectiveness of the training found in the Proposed Plan. SCE plans to monitor and adjust implementation accordingly.

VI. Alternative Plan #1

SCE developed Alternative Plan #1 as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Safety Controls	2018	2023	$ -	$ 14.1	0.43	0.030	0.34	0.024
C2	Contractor Safety Program	2018	2023	$ -	$ 1.1	0.42	0.383	0.33	0.301
M1b	Safety Culture Transformation – Expanded Training & Electronic Tailboards	2018	2023	$ 13.0	$ 41.4	2.26	0.042	1.78	0.033
M2	Industrial Ergonomics	2018	2023	$ -	$ 0.1	0.07	0.765	0.05	0.601
M3a	Office Ergonomics – Core Program	2018	2023	$ 14.6	$ 3.0	0.20	0.011	0.16	0.009
M3b	Office Ergonomics – Additional Software	2018	2023	$ 0.8	$ 0.3	0.06	0.060	0.05	0.047
M4a	Driver Safety Training – Full Training Population	2018	2023	$ -	$ 1.7	0.09	0.051	0.13	0.078
			Total - Alternative Plan #1	**$ 28.4**	**$ 61.6**	**3.52**	**0.039**	**2.83**	**0.031**

MARS = Multi-Attribute Risk Score
MRR = Mitigated Risk Reduction
RSE = Risk Spend Efficiency

A. Overview

This plan is premised on the idea of maximizing safety programs, tools, and training. It differs from the Proposed Plan in three ways:

- Replaces the proposed culture transformation program (M1a) with an expanded version that utilizes additional in-person training and electronic tailboards (M1b).
- Supplements the office ergonomics program (M3a) by adding ergonomics software (M3b).
- Adds a new driver safety program (M4a) that would be targeted at drivers with Class A licenses as well as drivers who are assigned to SCE vehicles that do not require a Class A license.

B. Execution feasibility

Because this plan would use more in-person training, logistical considerations are the primary factor affecting feasibility. For example, we may need more meeting rooms, additional qualified external facilitators, and in certain instances may need to rent external space to host the in-person training.

C. Affordability

Alternative Plan #1 is the highest cost option with the lowest RSE. Although this plan maximizes the implementation of potential mitigations that SCE could implement at this time, it does not offer a compelling value proposition. The higher cost of the plan ($10.9M more than the Proposed Plan) does not come with a commensurate risk reduction. Consequently, the RSE of Alternative Plan #1 (0.039) is lower than the Proposed Plan (0.040).

Expanding the Safety Culture Transformation to use more in-person training and electronic tailboards creates additional costs without a commensurate boost in risk reduction. While the ergonomics software would provide value to our overall ergonomic program, we believe the most appropriate approach at this time is to leverage the new ergonomic processes, such as *Set Up. Perform. Recover*. Once a stronger safety culture is established, we can continue to build upon our ergonomics program by implementing the software program, and leverage associated processes and data. Likewise, while driver safety training holds promise, further evaluation is needed as to whether now is the right time to implement.

D. Other Considerations

Due to the increased scope and extent of training and safety programs in this plan, it may exacerbate the "change fatigue" issues described above.

VII. Alternative Plan #2

SCE developed Alternative Plan #2 as shown in Table VII-1.

Table VII-1 – Alternative Plan #2 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan # 2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Safety Controls	2018	2023	$ -	$ 14.1	0.43	0.030	0.34	0.024
C2	Contractor Safety Program	2018	2023	$ -	$ 1.1	0.42	0.383	0.33	0.301
M1a	Safety Culture Transformation – Core Program	2018	2021	$ 13.0	$ 33.5	2.05	0.044	1.61	0.035
M2	Industrial Ergonomics	2018	2023	$ -	$ 0.1	0.07	0.767	0.05	0.602
M3a	Office Ergonomics – Core Program	2018	2023	$ 14.6	$ 3.0	0.20	0.012	0.16	0.009
M4b	Driver Safety Training – Limited Training Population	2018	2023	$ -	$ 1.7	0.07	0.041	0.11	0.068
			Total - Alternative Plan #2	**$ 27.6**	**$ 53.5**	**3.24**	**0.040**	**2.60**	**0.032**

MARS = Multi-Attribute Risk Score
MRR = Mitigated Risk Reduction
RSE = Risk Spend Efficiency

A. Overview

Alternative Plan #2 includes all controls and mitigations as the Proposed Plan. In addition, this plan includes M4b (Driver Safety Training – Limited Training Population), which is the version of the driver safety program that is limited to drivers with Class A licenses.

B. Execution feasibility

Alternative Plan #2 features the same feasibility considerations as the Proposed Plan, with the additional logistical requirements of the driver training program. The limited incremental work would not significantly impact SCE's ability to execute this plan.

C. Affordability

Alternative Plan #2 adds a relatively small incremental cost ($1.7M) due to the addition of M4b, but it provides a commensurate risk reduction, leading to the same RSE value (0.040).

D. Other Considerations

As described in above in the explanations of the Proposed Plan and Alternative Plan #1, SCE is sensitive to "change fatigue" and of overwhelming workers with too many safety initiatives. With that in mind, SCE is evaluating whether the driver safety program for Class A license holders can be implemented in the short term along with the activities in the Proposed Plan. SCE has not made this determination at the time. However, SCE will continue to evaluate driver safety mitigations for potential further inclusion in the 2021 GRC.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

Developing this RAMP chapter highlighted several opportunities to improve the ways we track, measure, and mitigate this risk.

1. The structure of the risk bowtie did not neatly align with how we historically captured safety-related data.

SCE had to use judgment to correlate historical data to specific drivers. Fortunately, improving how we collect, track, and evaluate safety data is an element of the Safety Culture Transformation program. For example, this effort will improve our cause evaluation processes, which will provide detailed information regarding incident causal factors that can better inform elements of the risk bowtie. Additionally, we are improving our contractor incident and injury reporting, which will provide details regarding causal factors and appropriate corrective actions for these incidents.

2. Focusing on serious injuries, and not all injuries, does not fully capture the risk associated with this chapter, as well as the full benefits of controls and mitigations.

For this RAMP report, SCE chose to evaluate four consequences: Serious Injuries, Fatalities, Reliability, and Financial. This approach is challenging, because the vast majority of safety incidents result in injuries are not severe enough to count as serious injuries. SCE takes every safety incident seriously, whether it is minor or serious. In many cases, a non-serious incident could have been serious.

SCE intends to further explore ways to incorporate both serious and non-serious injuries in its subsequent risk analyses. This way, we can evaluate the full benefits of controls and mitigations on reducing serious and non-serious safety outcomes.

3. While the RAMP probabilistic risk model helped us evaluate the effectiveness of our various safety controls and mitigations from a quantitative perspective, SCE expects our ongoing and emerging data collection efforts to further refine these analyses.

Developing this chapter required us to take a quantitative approach to understanding each control or mitigation's effect on drivers, outcomes, and consequences. This was challenging in many cases (e.g., quantifying the impact of cultural change). In these cases,

SCE attempted to use safety industry trends, case studies at other companies, and expert judgment.[22]

B. Data Collection & Availability

While developing this RAMP chapter, SCE identified areas for improvement in the availability and tracking of safety-related data. Some of these areas include capturing more granular information on safety incidents that occur, especially those that do not result in serious injuries or fatalities, and in a form that is more conducive to data analysis. Obtaining data on the financial costs of safety incidents (other than costs linked directly to the injury such as medical and worker's compensation) was also challenging. Much of the data analysis performed for this chapter required manually transposing and interpreting data across several datasets. This consumed substantial time and resources.

By deploying the Safety Data Strategy discussed in M1a (Safety Culture Transformation – Core Program), and expanding the scope and frequency of safety cause evaluations, SCE expects to improve the collection and availability of safety data. We intend to use the data to enhance our predictive modeling efforts and better target our safety analyses and mitigation approaches.

C. Performance Metrics

Table VIII-1 lists metrics that SCE currently tracks related to safety. This table is not an exhaustive listing of all safety metrics within the company. However, it reflects some of the more important metrics used to evaluate the company's safety performance. These metrics align to the drivers, outcomes and consequences of the risk bowtie developed for this chapter. They are the types of metrics that the compliance, controls, and mitigations in the Proposed Plan are intended to address.

[22] Please refer to WP Ch. 7, pp. 7.19 *(Subject Matter Expert Qualifications)*.

Table VIII-1 – Performance Metrics and Targets

Metric	Description
# of Employee Serious Injury	Count of SCE employee serious injuries, as defined by EEI and OSHA classifications
# of Employee Fatality	Count of employee fatalities
Days Away, Restrictions and Transfers (DART) Rate	Frequency measurement of workplace injuries and illnesses that result in time away from work, restricted job duties, or permanent transfers to new positions
Lost Workday Case Rate	Frequency measurement of workplace injuries and illnesses that result in time away from work
OSHA Recordable Injury Rate	Frequency measurement of work-related injuries and illnesses (including DART incidents) that result in loss of consciousness, restricted duty, job transfer, medical treatment beyond first aid, fatality or a significant injury or illness diagnosed by a physician or other licensed health care professional
# of Contractor Serious Injury	Count of contractor serious injuries, as defined by EEI and OSHA classifications, that perform work for SCE
# of Contractor Fatality	Count of contractor fatalities
# of Close Calls	Count of incidents reported by SCE workers where no personal injury was sustained, but where given a slight shift in time or position, injury easily could have occurred
# of Safety Observations	Count of observations submitted by SCE workers related to safety behaviors or hazard identification and mitigation
# of Employees trained in cognitive behavior skills	Count of employees trained through SCE's safety culture transformation program
# of inappropriate actions for vehicular operations	Count of incidents where SCE workers are performing inappropriate actions while operating vehicles

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Hydro Asset Safety

Chapter 8

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

SCE operates a portfolio of 81 hydro dams which support 33 hydroelectric plants that provide a combined 1,153 MW of generating capacity.[1] The dams are typically in remote mountainous areas and situated to capture the energy from high-elevation rain and snowmelt that flows downward. Most dams were constructed in the early 20th century, with the oldest dating to 1893 and the most recent dating to 1986. Approximately 8% of the electricity that SCE delivered to its customers in 2017 was generated by its hydro portfolio.[2] As discussed below, SCE already performs a number of compliance tasks and controls that cost-effectively mitigate the hydroelectric plant risks. Therefore, SCE's Proposed Plan recommends continuing these controls and does not contain incremental activities.

SCE approached its analysis of hydro dam risk by building on its existing Dam Safety Risk Assessment Program. SCE's Dam Safety Risk Assessment Program was initiated in 2008 and modeled after hydro dam risk management best practices established by the U.S. Bureau of Reclamation. The approach is based on identifying the potential ways a specific dam could fail, known as Potential Failure Modes (PFMs), then evaluating the likelihood of occurrence and the consequence of each PFM. SCE's hydro risk analysis presented in this RAMP chapter builds on this work.

SCE defined the risk event (i.e. the center of the bowtie) as the Uncontrolled Rapid Release of Water (URRW).[3] The scope is defined by dams with a hazard classification of "high-hazard" or greater as designated by the California Department of Water Resources Division of Safety of Dams (DSOD) and/or the Federal Energy Regulatory Commission (FERC).[4] For

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[1] SCE also operates two dams on Catalina Island that support its potable water supply.

[2] Edison International and Southern California Edison 2017 Annual Report, p. 120, *available at* https://www.edison.com/content/dam/eix/documents/investors/corporate-governance/2017-eix-sce-annual-report.pdf

[3] Future RAMP filings may expand scope to include appurtenant structures such as tunnels, flumes, flowlines and penstocks.

[4] Hazard classification is based on potential downstream impacts to life and property should the dam fail when operating with a full reservoir, as defined in the Federal Guidelines for Inundation Mapping of Flood Risk Associated with Dam Incidents and Failures (FEMA P-946, July 2013). A classification of "High" is given for a dam where one or more fatalities would be expected. DSOD created an "Extremely High" category in 2017 to identify dams that are expected to cause considerable loss of human life or result in an inundation area with a population of 1,000 persons or more). Five of SCE's 28 high-hazard dams are classified as Extremely High-Hazard.

convenience, SCE will refer to these facilities as high-hazard dams. SCE believes that this is an appropriate scope for the analysis, as the facilities have been identified by the relevant federal and/or state regulators as having the greatest potential to cause loss of human life.

This chapter discusses three drivers that could potentially lead to URRW: seismic events, flooding, and failure under normal operations. Risk outcomes are described in terms of three categories: the facility is inoperable and there is no significant inundation; there is inundation of an unpopulated area; there is inundation of populated and unpopulated areas. The overall likelihood of a catastrophic failure of one of SCE's 28 high-hazard dams is estimated as one failure every 175 years.

This chapter describes four compliance activities:[5]

- Hydro Operations (CM1): This includes monitoring and controlling reservoir levels and flows, routine observation and data collection by trained personnel, and regular testing of critical systems.
- Hydro Maintenance (CM2): This includes repairing minor/localized deterioration and maintaining operability of critical systems.
- Dam Safety Program (CM3): This program utilizes qualified engineers, supported by internal and external Subject Matter Experts, to help ensure compliance with laws and regulations and to identify and prioritize potential issues at dams.
- External Inspections (CM4): Regular regulatory inspections are performed by the FERC and DSOD. Additionally, independent Consultant Safety Inspections are performed at five-year intervals for each dam in accordance with Chapter 18 of the Code of Federal Regulations (18 CFR) Part 12D.

In addition to the compliance activities, this chapter describes six controls:[6]

- Seismic Retrofits (C1): Reinforcing dams to withstand seismic loading and/or making improvements to maintain seismic restrictions on reservoir levels.
- Dam Surface Protection (C2): Protecting upstream dam surfaces with geomembrane liner systems.[7]

[5] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
[6] C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.
[7] A geomembrane liner extends the life of a dam by reducing the degradation that can occur from water entering concrete pores and then freezing.

- Spillway Remediation and Improvement (C3): Repairing and improving structures used to safely pass water flows from flooding events.[8]
- Low-Level Outlet Remediation and Improvement (C4): Repairing and improving systems used to draw down dam reservoir levels in a controlled manner.
- Seepage Mitigation (C5): Repairing or enhancing the structure and/or drainage systems of earthen dams to inhibit the initiation and progression of internal erosion.
- Instrumentation / Communication Improvements (C6): Improving instrumentation and communication systems used to detect conditions that may indicate dam failure.

Finally, this chapter describes three potential mitigations:[9]

- Proactively removing high-hazard dams to proactively reduce risks (M1).
- Relocating campgrounds or campsites within potential inundation zones (M2).
- Purchasing private residences within potential inundation zones (M3).

SCE's has developed three risk mitigation plans for consideration:

- The Proposed Plan consists of continuing all current controls (C1 through C6).
- Alternative Plan #1 adds proactive removal of a small number of dams (M1) to the Proposed Plan.
- Alternative Plan #2 adds relocation of campgrounds and campsites (M2) and purchase of private residences (M3) to the Proposed Plan (but does not add M1).

This chapter also includes a technical appendix that pilots an analytical approach for a longer-term risk analysis. SCE selected Hydro Asset Safety as the pilot for this alternative approach due to the long-lived nature of many of its risk controls and mitigations. The technical appendix uses the same bowtie components, controls, and mitigations that were evaluated in the short-term analysis.

[8] A spillway is a structure that is used to make controlled releases of water flows from a dam into a downstream area, typically the riverbed of the dammed river itself. Water normally flows over a spillway only during flood periods.

[9] M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are addressed in Section IV of this chapter.

B. Scope

The scope of this Chapter is summarized in Table I-1.

Table I-1 – Chapter Scope

In Scope	• URRW due to failure of a high-hazard dam caused natural hazard (e.g., flood, earthquake), deterioration or incorrect operation
Out of Scope[10]	• URRW due to intentional malicious acts performed by an SCE Employee or Contractor • URRW due to an adversary gaining control of a high-hazard dam through physical access • URRW due to an adversary gaining control of a high-hazard dam through cyber access

C. Summary Results

Table I-2 summarizes the baseline risk analysis presented in his chapter, the controls and mitigations contemplated, and the portfolio results over the 2018 – 2023 period. Figure I-1 illustrates the composition of consequences within the baseline risk.

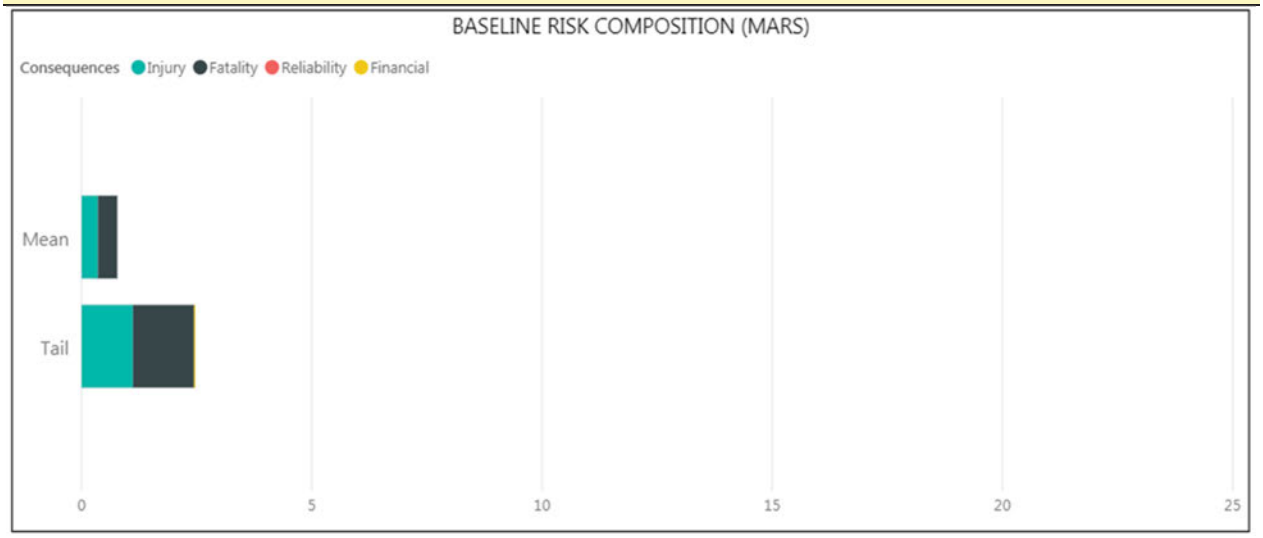
[10] The three scenarios that are classified as out of scope for this chapter are covered within the Employee, Contractor & Public Safety, Physical Security, and Cyber Attack chapters, respectively.

Table I-2 – Summary Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	Name	Proposed	Alternative #1	Alternative #2
C1	Seismic Retrofit	x	x	x
C2	Dam Surface Protection	x	x	x
C3	Spillway Remediation and Improvement	x	x	x
C4	Low Level Outlet Improvement	x	x	x
C5	Seepage Mitigation	x	x	x
C6	Instrumentation and Communication Improvements	x	x	x
M1	Proactive Dam Removal		x	
M2	Relocation of Campgrounds			x
M3	Purchase of Private Residences			x
Mean (MARS)	*Cost Forecast ($ Million)*	$8	$33	$10
	Baseline Risk	0.77	0.77	0.77
	Risk Reduction (MRR)	0.18	0.21	0.19
	Remaining Risk	0.59	0.57	0.59
	Risk Spend Efficiency (RSE)	0.022	0.006	0.019
Tail Average (MARS)	*Cost Forecast ($ Million)*	$8	$33	$10
	Baseline Risk	2.47	2.47	2.47
	Risk Reduction (MRR)	0.58	0.65	0.60
	Remaining Risk	1.88	1.82	1.87
	Risk Spend Efficiency (RSE)	0.069	0.020	0.061

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS score is 100.

II. Risk Assessment

A. Background

Since 2008, SCE has maintained a Dam Safety Risk Assessment program, modeled after the "Risk Management – Best Practices and Risk Methodology," program established by the United States Bureau of Reclamation (USBR) in the mid-1990s.[11] The SCE Dam Safety Risk Assessment Program has been used to help understand, prioritize, and address potential dam safety issues across SCE's portfolio of dams.

The 28 high-hazard dams in scope for RAMP range in age from 32 to 112 years, with an average age of 90, and encompass a wide range of dam types, including:

- Earthfill – Balsam Meadow Dike, Bishop Intake 2 Dam, Lundy Lake Dam, Mammoth Pool Dam, Vermilion Valley Dam, Thompson Dam, and Wrigley Reservoir.
- Rockfill – Balsam Meadow Dam, Hillside Dam, Portal Forebay Dam, Rhinedollar Dam, Sabrina Lake Dam, Saddlebag Dam, and Tioga Lake Dam.
- Concrete Gravity – Big Creek Dam 7, Huntington Lake Dam 1, Huntington Lake Dam 2, Huntington Lake Dam 3, Kern River 1 Diversion, and Shaver Lake Dam.
- Concrete Arch – Big Creek Dam 4, Big Creek Dam 5, Big Creek Dam 6, Rush Meadows Dam, and Tioga Lake Auxiliary Dam.
- Concrete Multiple-Arch – Agnew Lake Dam, Florence Lake Dam, and Gem Lake Dam.

1. Federal Dam Safety Risk Management Practices

The USBR is responsible for overseeing the management of hundreds of high-hazard dams and dikes[12] that comprise a significant portion of the water resources in the western U.S. The USBR developed principles and methods for assessing and managing risk to prioritize investments in dams and make more effective use of their resources. The USBR framework has been updated, adopted and modified by the USBR and other federal dam owners, such as the U.S. Army Corps of Engineers (USACE). It forms the basis of the recently released Federal Emergency Management Agency (FEMA) Guidelines for Dam Safety Risk Management[13] and the

[11] The United States Bureau of Reclamation is a federal agency within the U.S. Department of the Interior. The Bureau of Reclamation oversees water resource management, specifically as it applies to the oversight and operation of the diversion, delivery, and storage projects that it has built throughout the western United States for irrigation, water supply, and attendant hydroelectric power generation.
[12] A long wall or embankment built to prevent flooding.
[13] "Federal Guidelines for Dam Safety Risk Management," Federal Emergency Management Agency, Report P-1025, January 2015.

FERC guidelines for Risk Informed Decision Making (RIDM),[14] which will be referred to as the Federal risk guidelines. Federal risk guidelines are based on two connected concepts:

- Tolerable Risk: A level of risk deemed acceptable by society in order that some particular benefit can be obtained, if that risk is being properly managed by the owner, and is reviewed and reduced as practicable; and,
- A risk has been appropriately reduced if it is As Low as Reasonably Practicable (ALARP).

The federal guidelines employ an f-N chart for evaluating risk at individual dams. The chart included in the FERC RIDM Guidelines is shown in Figure II-1. This chart plots the annual frequency of occurrence for a PFM (f) against the expected loss of life should the PFM occur (N). Four "zones" on the f-N chart are identified by the guidelines:

- Risks are unacceptable except in extraordinary circumstances. This zone is defined by the region where average annual life loss is greater than one fatality per 1,000 years, as indicated by reference line "A" in Figure II-1.
- Risks are generally tolerable, but ALARP considerations should be employed. This zone is defined by the region where average annual life loss is less than one fatality per 100,000 years, indicated by reference line "B" in Figure II-1.
- ALARP region – Risks are intolerable unless ALARP is satisfied. This zone is defined as the region between reference lines "A" and "B" in Figure II-1.
- Special considerations – Risks have extremely high consequences but low probability; a thorough review of the benefits and risk of the project is needed to determine tolerability. This zone is defined as the region bounded by expected fatalities greater than 1,000, but annual probability less than 1 in 1,000,000. This is indicated by reference line "C" in Figure II-1.

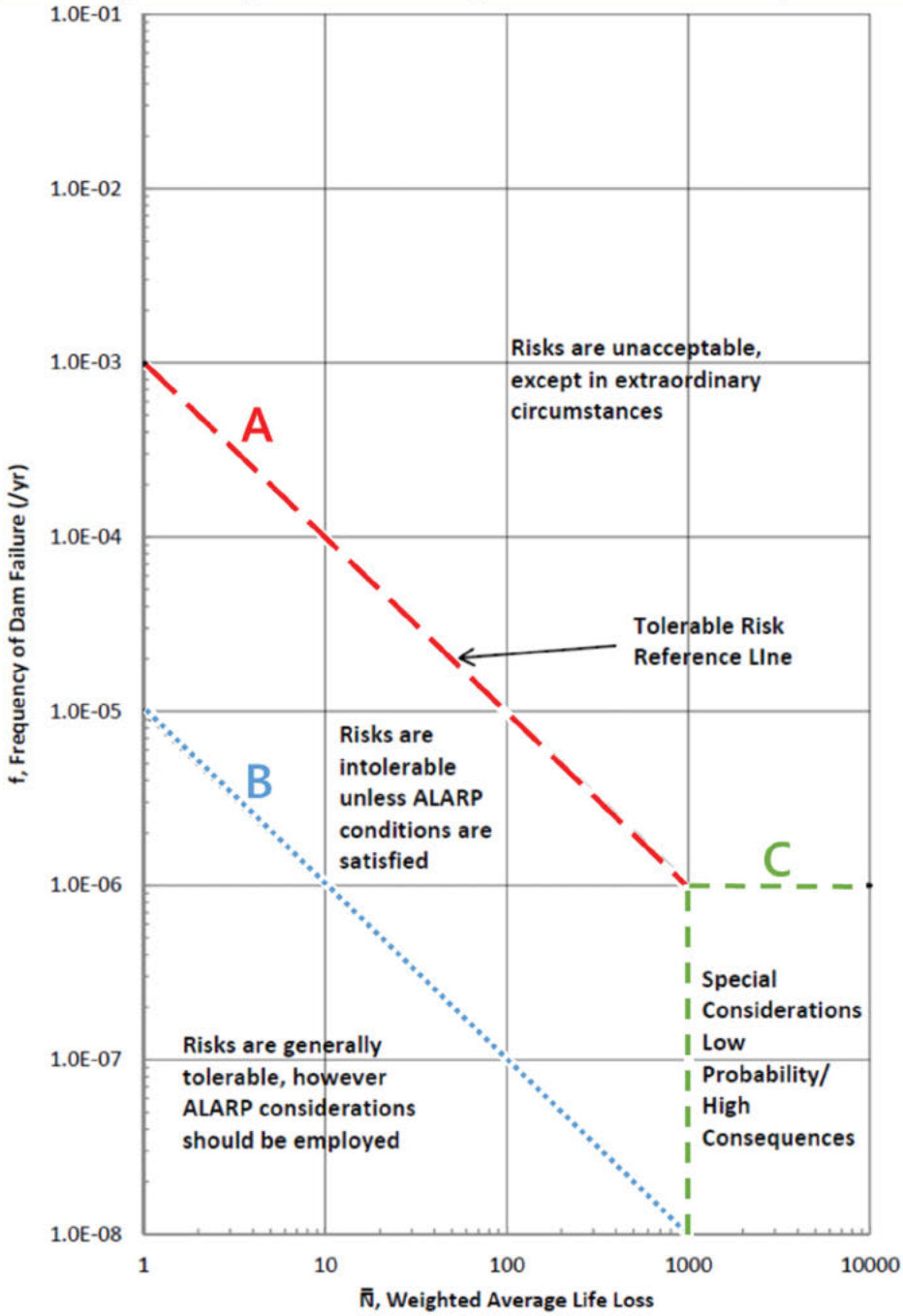
The FERC RIDM guidelines list the following criteria to evaluate if ALARP is satisfied:

- The cost-effectiveness of potential incremental risk reduction measures.
- The level of risk in relation to the tolerable risk reference lines.
- Disproportionality of the proposed investment relative to the benefits.
- Good Practice evidenced by compliance with FERC Engineering Guidelines or other industry-recognized standard or good practice.

[14] "Risk-Informed Decision Making (RIDM) Risk Guidelines for Dam Safety, Version 4.1," Federal Energy Regulatory Commission Division of Dam Safety and Inspections, March 2016.

- Societal concerns as revealed by consultation with the community and other stakeholders.
- Other factors, including duration of the risk, availability of risk reduction options, potential for creation of new risks, adequacy of the PFMA, consideration of standards, and benchmarking with other dam owners.

Figure II-1 – f-N Chart from FERC Risk-Informed Decision-Making Guidelines



Two types of risk analyses are used under FERC RIDM guidelines:

- Semi-Quantitative Risk Analyses (SQRA), where the likelihood and consequences for each PFM are classified into broad bins by teams of SMEs. The primary purpose of SQRA is to determine which PFMs are of most concern for a dam or portfolio of dams and require additional study and evaluation.
- Quantitative Risk Analyses (QRA), where additional field investigations, analyses and study are used to develop quantitative estimates of the probability of failure and the consequences of failure for the most critical PFM(s) of a dam or portfolio of dams. The primary purpose of QRA is to inform decision-making around dam safety investments, and typically involves analyzing both the risk under existing conditions and the risk under a set of proposed mitigations.

The FERC RIDM Guidelines, as well as those used by the USBR and USACE, emphasize that risk analyses are not intended to be used as the sole criteria for judging the safety of a dam. Rather, they are a component of a "Dam Safety Case" that presents the rationale for a proposed course of action to manage risk.

2. State Dam Safety Risk Management

The California DSOD does not have formal guidelines or criteria regarding dam safety risk. However, recent California law has directed DSOD to propose amendments to its dam safety inspection and re-evaluation protocols "to incorporate updated best practices, including risk management, to ensure public safety" by January 1, 2019.[15]

3. SCE Dam Safety Risk Management

SCE applies the principles outlined in the federal guidelines to managing risks identified for its dams. The defined inventory of dam risks is the set of PFMs developed through the FERC-required Potential Failure Modes Analysis (PFMA) process.[16] SCE has assigned likelihood and consequence categories to each of these PFMs through SQRA workshops involving SCE personnel, outside experts and regulators. The current categorization of dam risks resulting from these SQRAs is summarized in Figure II-2, which shows how the 230 PFMs are distributed across the likelihood and consequence categories. These results have been used by SCE to identify and prioritize dam safety projects, and serve as the foundation of the risk model presented in the chapter.

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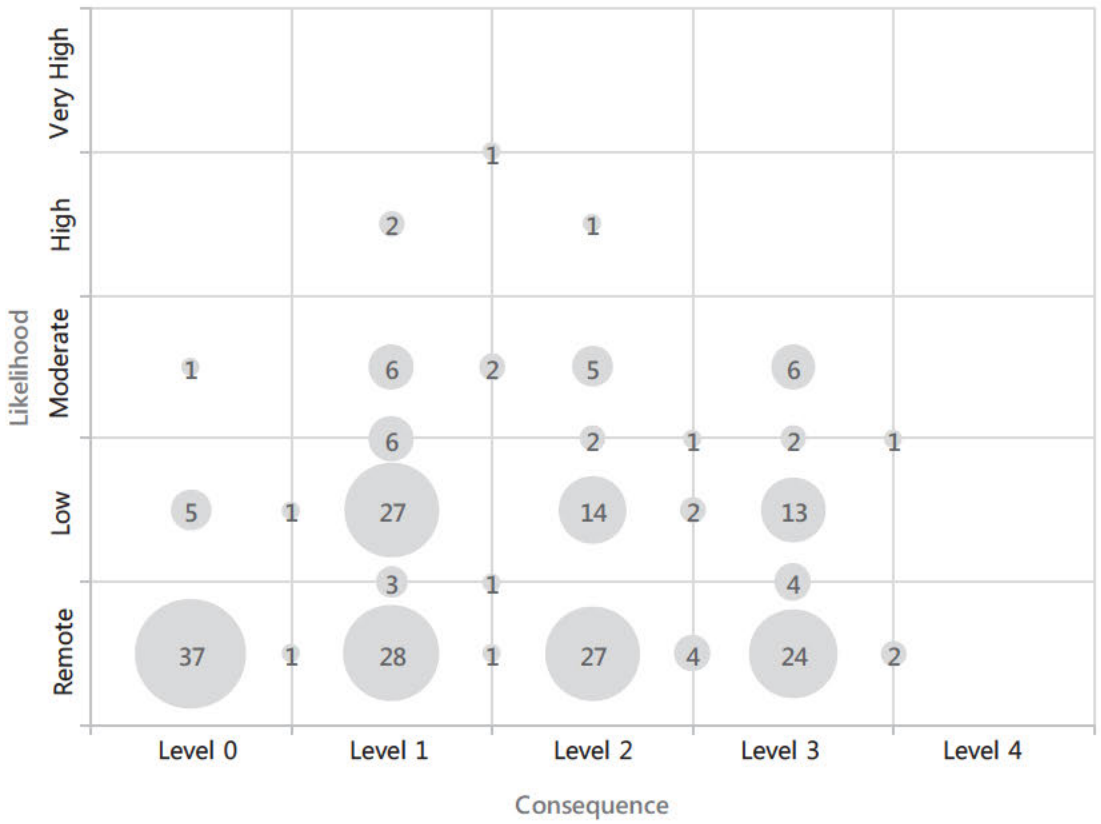
[15] "AB-1270 Dams and Reservoirs: Inspections and Reporting", February 26, 2018. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB1270

[16] Starting in 2002, FERC has required owners of high-hazard dams to perform PFMAs and update them every five years.

Figure II-2 – Risk Categorization of Potential Failure Modes for High-Hazard Dams

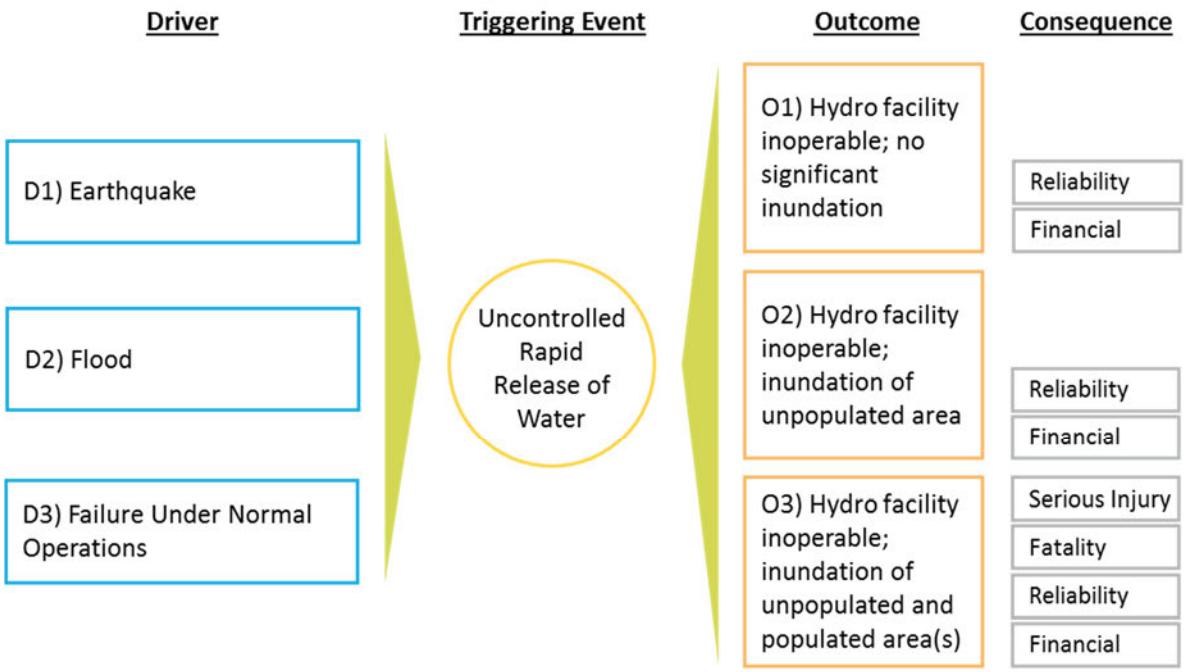


SCE has not previously performed QRA but is currently engaged in a pilot program under the FERC RIDM Guidelines (the second such project in the country) that will include a QRA for a single dam. This project is expected to conclude in 2019.

B. Risk Bowtie

SCE used the bowtie methodology, as shown in Figure II-3, to develop a quantitative risk model specific to SCE's high-hazard dams. This model uses a combination of SCE-specific data, industry data, and guidance from SCE dam safety experts, to gain a better understanding of the risk drivers and consequences for a dam failure. The bowtie presents the risk drivers, outcomes, and consequences; additional details can be found in the sections below.

Figure II-3 – Hydro Asset Safety Risk Bowtie



C. Driver Analysis

SCE has identified three drivers (Earthquake; Flood; Failure under Normal Operations) that could lead to the uncontrolled rapid release of water.

The risk model uses data based on the SCE Dam Safety Risk Register, which tracks the most current assessment of the likelihood and consequence of every identified PFM for each dam.[17] A total of 230 PFMs are associated with the 28 SCE dams evaluated for RAMP. Each PFM is mapped to one of the identified drivers (defined below); the estimated frequencies of all PFMs within a driver category are summed to produce the total driver frequency. Figure II-4 shows the projected 2018 frequency for each of these drivers.

[17] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)* and the supplemental worksheets in its electronic version.

Figure II-4 – 2018 Projected Driver Frequency

Name	Freq	Frequency
D1 - Earthquake	0.0027	
D2 - Flood	0.0024	
D3 - Failure Under Normal Operations	0.0006	

1. D1 – Earthquake

Earthquakes must be taken into account for dams located in California. Several SCE dams, particularly those on the eastern slopes of the Sierra Nevada Mountains, are near known faults. For all dam sites, the possibility of activity on unidentified faults cannot be ruled out. The ground motions caused by earthquakes can negatively impact dams in a variety of ways:

- The material of embankment dams or their foundations may settle or slide such that the crest of the dam falls below the reservoir level. This allows water to spill over and erode the downstream material, leading to a complete breach. This nearly occurred at Lower Van Norman Dam when the 1971 San Fernando earthquake resulted in the loss of the upper 30 feet of the dam. The reservoir was only half-full at the time; had it been at full capacity, the resulting flood would likely have killed tens of thousands in the San Fernando Valley.
- Concrete dams may suffer significant cracking and loss of strength, compromising their ability to hold back the reservoir water. Movement of the rock foundations and abutments can also trigger a loss of support for the structure, leading to dam failure. While there are no recorded cases of concrete dams failing as a result of an earthquake, several have been damaged, such as Koyna Dam (1967) and Pacoima Dam (1971, 1994).

Assessing PFMs related to seismic events occurred in facilitated Risk Assessment Workshops that included SCE Operations and Dam Safety personnel, outside consulting experts, and engineers from FERC and DSOD.[18] Risk Assessment Workshop participants considered all available information, including probabilistic seismic hazard evaluations for each dam site and seismic stability analyses.

A total of 61 PFMs, across the portfolio of high-hazard dams, were mapped to this driver. The combined annual probability[19] of occurrence of these PFMs is estimated at 0.26%,

[18] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)* and the supplemental worksheets in its electronic version.

[19] The likelihood of a given event's occurrence, which is expressed as a number between 1 and 0.

or 1 in 385 years. The seismic driver is attributable to 47% of the overall frequency of triggering events.

2. D2 – Flood

Flooding typically occurs because of heavy precipitation or snowmelt. Weather-related flooding events typically are easier to predict in the short term. SCE manages such events by using reservoir storage, passing water through spillways and outlets, and coordinating high-flow events with upstream and downstream dam operators. However, if water inflows exceed the capacity of the system, then the stability of the dam may be threatened.

- Water that goes over (i.e., overtops) an embankment dam will likely begin to erode and carry away the downstream material, which can progress to a complete breach. This occurred in the 1889 failure of South Fork Dam which claimed 2,209 lives in one of the worst disasters in U.S. history.[20]
- The rock foundations and abutments of concrete dams can also be vulnerable to erosion from extreme flood flows, leading to a loss of support for the dam and failure (Austin Dam 1911, Malpasset Dam 1959).

As indicated above, assessing PFMs related to seismic events occurred in facilitated Risk Assessment Workshops. These workshops included SCE Operations and Dam Safety personnel, outside consulting experts, and engineers from FERC and DSOD. [21] Risk Assessment Workshop participants considered all available information, including evaluating the probable maximum flood for each dam, and evaluating the stability of the dam under the resulting reservoir levels.

A total of 70 PFMs were mapped to this driver. The combined annual probability of occurrence of these PFMS is estimated at 0.24%, or 1 in 417. The flood driver is attributable to 44% of the overall frequency of triggering events.

3. D3 – Failure under Normal Operations

Dam failures have also been observed to occur in the absence of extreme loading events such as flood and seismic events. These types of failures are most common in dams with design or construction flaws, and generally occur within the first few years of operation. Some examples are the failures of St. Francis Dam (1928), Teton Dam (1976) and Camara Dam

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[20] "Case Study: South Fork Dam (Pennsylvania, 1889)" Lessons Learned from Dam Incidents and Failures, Association of State Dam Safety Officials. http://damfailures.org/case-study/south-fork-dam-pennsylvania-1889/

[21] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)*

(2004).[22] Though less common, dams that have functioned safely for decades may also fail due to degradation.

- Embankment dams can experience "piping" failures, where seepage through the dam begins to carry away the material. This creates an expanded cavity that could collapse, lowering the crest of the dam and allowing water to run over the top, thereby eroding the downstream material and progressing into a full breach.
- Concrete dams may experience a loss of strength due to "freeze-thaw" cycling[23] that eventually compromises the ability of the structure to retain the reservoir.
- Dam subsystems such as outlet pipes or spillway gates may also deteriorate over time, leading to failure and uncontrolled releases, such as the Folsom Dam (1995).
- Finally, failure to follow Station Orders and other operating procedures could potentially lead to a dangerous discharge of water. FERC determined that this led to a drowning death at Varick Dam (2010).[24]

In the Risk Assessment Workshops referenced above,[25] participants considered all available information, including design documents, surveillance and monitoring data, and previous repairs and improvements.

A total of 80 PFMs were mapped to this driver. The combined annual probability of occurrence of these PFMs is estimated at 0.05%, or 1 in 2,000. The failure under normal operations driver is attributable to 9% of the overall frequency of triggering events.

D. Triggering Event – Uncontrolled Rapid Release of Water

SCE defines the Triggering Event as the Uncontrolled Rapid Release of Water (URRW) from a Hydro High-Hazard Dam. This definition has been used by SCE's Dam & Public Safety department since 2008 and is consistent with the Federal Guidelines for Dam Safety Glossary of Terms,[26] which defines dam failure as "characterized by the sudden, rapid, and uncontrolled

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[22] The owners of these dams were the City of Los Angeles, The United States Bureau of Reclamation (USBR), and Brazil.

[23] A process where water permeates tiny cavities in concrete and freezes. Since ice occupies approximately 9% more volume than the same amount of liquid water, this stresses the concrete and may result in cracking and expansion of the cavities. When thawing occurs, liquid water fills the expanded cavity and the process repeats.

[24] "Erie Boulevard Hydroelectric, L.P., Order Approving Stipulation and Consent Agreement," Federal Energy Regulatory Commission, Docket No. IN13-12-000. January 15, 2014.

[25] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)*

[26] "Federal Guidelines for Dam Safety Glossary of Terms." Federal Emergency Management Agency, Report 148, April 2004.

release of impounded water." While any type of damage or malfunction that prevents a hydroelectric high-hazard dam from functioning as intended can be considered a failure, SCE has identified uncontrolled, rapidly-occurring discharges as the greatest potential threat to the safety of the downstream population.[27]

E. Outcomes & Consequences

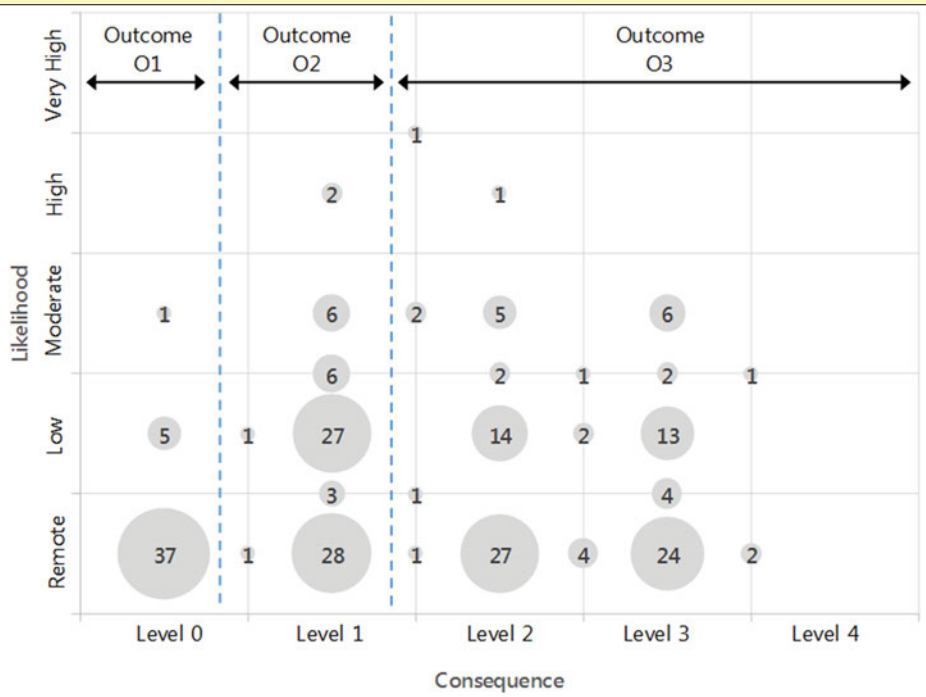
SCE has identified three potential outcomes should URRW occur. Figure II-5 depicts the estimated likelihood of the three outcomes.

Figure II-5 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Hydro Facility Inoperable; No Significant Inundation	2.0 %	
O2 - Hydro Facility Inoperable; Inundation of Unpopulated Area	33.4 %	
O3 - Hydro Facility Inoperable; Inundation of Unpopulated & Populated Area(s)	64.6 %	

Each of the 230 PFMs evaluated in the SCE portfolio is uniquely mapped to one of the three outcomes based on severity as shown in Figure II-6.

Figure II-6 – Mapping of Potential Failure Modes to Outcomes



[27] Controlled discharges afford an opportunity for planning and communication efforts to mitigate the impacts, while a slowly occurring discharge allows for evacuating potentially impacted areas. Hydro Asset failures resulting in URRW have been the focus of SCE's previous risk assessment activities for dams, and will remain the focus in this RAMP chapter.

Figure II-7 illustrates the composition of the modeled baseline risk in terms of each consequence dimension. The sections that follow describe the inputs used to derive these risks.

Figure II-7 – Modeled Baseline Risk Composition by Consequence (Natural Units)

1. O1 – Hydro Facility Inoperable; No Significant Inundation

This outcome is occurs when a dam failure causes URRW, but it does not result in significant downstream inundation (i.e., the water is contained within the normal banks of the stream). If the dam is directly connected to a hydroelectric plant, that plant will be inoperable. If the dam is a storage reservoir, that storage capacity will be unavailable. Hydro facilities will remain unavailable until the damage is repaired. Approval from federal and/or state regulators will also be required to resume operation.

Of the 230 assessed PFMs, 43 have consequences that are mapped to this outcome. The total frequency of these PFMs represents approximately 2% of the overall Triggering Event frequency.[28]

Potential consequences from O1 are summarized on an annualized basis in Table II-1. Reliability consequences are associated with localized areas served by hydroelectric plants that are periodically "islanded" from the grid. Financial consequences are associated with lost generating capability and the need to procure replacement power. For O1, the estimate of annual impacts is 13 customer minutes of interruption (CMI) and $163 of financial harm on a mean basis, and 132 CMI and $1,632 of financial harm and on a tail-average basis.

[28] Please refer to WP Ch. 8, pp. 8.1 – 8.3 *(Baseline Risk)* and the supplemental worksheets in its electronic version.

Table II-1 – Outcome 1 (Hydro Facility Inoperable): Consequence Details

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			SCE used transmission line outage duration data (2005-2016), occurrences of hydro plant "Islanding" (2009-2017), 2010 census household counts to estimate reliability impact of a hydro plant being out of service for a year. Impacts were associated to PFMs for dams supporting potentially islanded hydro plants and averaged over all PFMs mapped to O1.	SCE used annual generation output for hydro plants (1998-2017) to estimate the value of generation lost due to each hydro plant being out of service for a year. Impacts were associated with PFMs for dams supporting each plant and averaged over all PFMs mapped to O1.
Model Outputs	NU - Mean			13 CMI	$163
	NU - Tail Avg			132 CMI	$1,632

2. O2 – Hydro Facility Inoperable; Inundation of Unpopulated Area

This outcome occurs when a dam failure causes URRW, resulting in loss of operability of the associated hydro assets, and the inundation of unpopulated downstream areas. For the dams considered in RAMP, these areas would generally be forested areas that people do not regularly occupy or travel.

Of the 230 assessed PFMs, 74 have consequences that are mapped to this outcome. The total frequency of these PFMs represents approximately 33% of the overall Triggering Event frequency.

Potential consequences from O2 are summarized on an annualized basis in Table II-2. Reliability consequences are associated with localized areas served by hydroelectric plants that are periodically “islanded” from the grid. Financial consequences are associated with lost generating capability and the need to procure replacement power, as well as damage caused by inundation. For O2, the estimate of annual impacts is 65 customer minutes of interruption (CMI) and $30,930 of financial harm on a mean basis, and 648 CMI and $309,299 of financial harm on a tail-average basis.

Table II-2 – Outcome 2 (Inundation of Unpopulated Areas): Consequence Details

Outcome 2		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			SCE used transmission line outage duration data (2005-2016), occurrences of hydro plant "Islanding" (2009-2017), 2010 census household counts to estimate reliability impact of a hydro plant being out of service for a year. Impacts were associated to PFMs for dams supporting potentially islanded hydro plants and averaged over all PFMs mapped to O2.	SCE used annual generation output for hydro plants (1998-2017) to estimate the value of generation lost due to each hydro plant being out of service for a year. SCE used financial impact scoring performed by Dam Safety engineers in 2016 to estimate the costs due to inundation for failure of each dam. The combined impacts were associated with PFMs for dams supporting each plant and averaged over all PFMs mapped to O2.
Model Outputs	NU - Mean			65 CMI	$30,930
	NU - Tail Avg			648 CMI	$309,299

3. O3 – Hydro Facility Inoperable; Inundation of Unpopulated and Populated Area(s)

The worst-case outcome considered is a dam failure resulting in URRW that inundates a populated area. This impact is in addition to the inundation of unpopulated areas and loss of operability for the associated hydro facilities.

Of the 230 assessed PFMs, 113 have consequences that are mapped to this outcome. The total frequency of these PFMs represents approximately 65% of the overall Triggering Event frequency.

Potential consequences from O3 are summarized on an annualized basis in Table II-3. Safety consequences, including serious injuries and fatalities are associated with pedestrians, occupied vehicles, or occupied structures caught by the released water. Reliability consequences are associated with disruption of service to localized areas due to direct damage to the electrical system, as well as periodic disruptions to areas served by hydroelectric plants

that are periodically "islanded" from the grid. Financial consequences are associated with lost generating capability and the need to procure replacement power, as well as damage caused by inundation. For O3, the estimate of annual impacts is 0.10 serious injuries, 0.03 fatalities, 3,252 customer minutes of interruption (CMI) and $454,867 of financial harm on a mean basis, and 1.00 serious injuries, 0.28 fatalities, 32,523 CMI and $4,548,672 of financial harm on a tail-average basis.

Table II-3 – Outcome 3 (Inundation of Populated Areas): Consequence Details

Outcome 3		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE used internal estimates for potential life safety impacts of each PFM developed during Dam Safety Risk Assessments (2009-2018), which are informed by inundation mapping and consequence evaluations. Serious Injuries were estimated for each PFM by scaling Fatalities based on draft FEMA guidance document. Consequences were averaged over all PFMs mapped to O3.	SCE used internal estimates for Fatalities associated with each PFM developed during Dam Safety Risk Assessments (2009-2018), which are informed by inundation mapping and consequence evaluations. Consequences were averaged over all PFMs mapped to O3.	SCE used transmission line outage duration data (2005-2016), occurrences of hydro plant "Islanding" (2009-2017), 2010 census household counts to estimate reliability impact of a hydro plant being out of service for a year. Impacts were associated to PFMs for dams supporting potentially islanded hydro plants. SCE identified areas where URRW could impact electrical assets and estimated impact of a one week outage. Impacts were associated to PFMs for dams capable of causing outages. Combined reliability impacts were averaged over all PFMs mapped to O3.	SCE used annual generation output for hydro plants (1998-2017) to estimate the value of generation lost due to each hydro plant being out of service for a year. SCE used financial impact scoring performed by Dam Safety engineers in 2016 to estimate the costs due to inundation for failure of each dam. The combined impacts were associated with PFMs for dams supporting each plant and averaged over all PFMs mapped to O3.
Model Outputs	NU - Mean	0.10	0.03	3,252 CMI	$454,867
	NU - Tail Avg	1.00	0.28	32,523 CMI	$4,548,672

III. Compliance & Controls

SCE has existing programs and processes in place that serve to reduce the likelihood of the risk materializing, or the impact level of a risk event should it occur. All of these activities are summarized in Table III-1 and discussed in more detail in the sections that follow.

As discussed in Section I, compliance activities (CM1-CM4) are required to adhere to laws and regulations governing dam safety. Electing not to perform this work for a dam would likely result in an order from the FERC to cease generation, and possibly revocation of the associated FERC license (as was recently issued to Boyce Hydro in 2018).[29] Similarly, DSOD has the authority to impose reservoir restrictions and to revoke the certificate of approval required to operate a dam in California if it determines that there is a danger to life and property. Consequently, SCE did not consider a "baseline" risk that lacked these compliance activities and accordingly did not risk-score compliance activities.

Hydro Capital Maintenance Refurbishment and/or Replacement activities (C1-C6) are controls consisting of capital investments necessary for maintaining dam infrastructure and equipment. Infrastructure work includes projects such as dam improvements needed to address identified areas of concern. SCE considered all work forecast to occur in 2018-2023 for the 28 high-hazard dams and evaluated the work's impact on mitigating the RAMP drivers, outcomes and consequences.[30,31]

[29] "Boyce Hydro Power, LLC; Order Proposing Revocation of License." Federal Energy Regulatory Commission, Document 83 FR 8253. February 26, 2018.
[30] The process used to forecast Hydro capital expenditures begins with staff identifying equipment needing capital replacement or refurbishment, safety concerns or regulatory compliance issues requiring plant additions or modifications (which includes Hydro relicensing), and other site modifications or improvements needed to address operations or maintenance needs.
[31] The risk-reduction achieved by the controls was modeled using input from Subject Matter Experts (SMEs). Please refer to WP Ch. 8, pp. 8.4 – 8.13 *(RAMP Mitigation Reduction Workpaper)* and the supplemental worksheets in its electronic version for details on modeling of controls, and WP Ch. 8, p. 8.14 (Subject Matter Expert Judgement) for qualifications of the participating SMEs.

Table III-1 – Compliance and Control Activities

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Reduced	2017 Recorded Costs ($M)	
					Capital	O&M
CM1	Hydro Operations	Not Modeled	Not Modeled	Not Modeled	$ -	$ 1.2
CM2	Hydro Maintenance	Not Modeled	Not Modeled	Not Modeled	$ -	$ 1.3
CM3	Dam Safety Program	Not Modeled	Not Modeled	Not Modeled	$ -	$ 1.2
CM4	External Inspections	Not Modeled	Not Modeled	Not Modeled	$ -	$ 0.7
C1	Seismic Retrofit	D1	-	-	$ -	$ -
C2	Dam Surface Protection	D3	-	-	$ 5.3	$ -
C3	Spillway Remediation and Improvement	D2	-	-	$ 0.3	$ -
C4	Low Level Outlet Improvements	-	O2, O3	S-I, S-F, F	$ -	$ -
C5	Seepage Mitigation	D3	-	-	$ -	$ -
C6	Instrumentation / Communication Enhancements	-	O3	S-I, S-F	$ 0.7	$ -

Consequences Abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial – F

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

A. CM1 – Hydro Operations

SCE is required to operate its hydroelectric facilities in a safe manner. This includes maintaining situational awareness of the system through inspections and instrumentation, regulating the water flows and reservoir levels, and operating hydroelectric generating units.

SCE's trained hydro operations and maintenance personnel routinely observe dams. These personnel are stationed in the watersheds where the SCE dams are located. During regular visits to the dams, these personnel perform visual observations of the dams, collect monitoring data, and report any changed or unusual conditions that could potentially impact dam safety or SCE's ability to operate the facility's spillways and outlet structures in a safe manner.

Operations personnel regulate water flows to help ensure efficient use of water and maximum generation from resources. This activity includes:

- Regularly inspecting the reservoir facilities;
- Making gate changes to regulate water releases;
- Cleaning the grids at flowline entrances; and
- Removing debris from in and around flowlines, flumes, penstocks and other typical Hydro waterways.

Station Orders are created to help ensure that controlled releases are performed safely. All station personnel are required to follow station orders.

Dispatching work includes directing all O&M activities associated with the powerhouses in the Big Creek and Bishop Creek/Mono Basin areas, and the associated transmission and distribution facilities. The dispatching function is critical to successfully operating these facilities. The Big Creek Control center contains all the supervisory control equipment for the Big Creek facilities, while the Bishop Control substation contains all the supervisory control equipment for the Bishop Creek, Mono Basin, and Kern River facilities.

Unmanned East End and Kaweah facilities have alarms that notify the Bishop Control substation of unusual events through a dial-up system. This 24-hour surveillance of the operating equipment from a central point helps maintain system integrity and operational effectiveness.

B. CM2 – Hydro Maintenance

SCE is required to maintain its hydroelectric facilities, including dams, in a safe operating condition.

This activity includes planning and scheduling equipment maintenance activities at reservoirs, dams, canals, flumes, and other appurtenant hydraulic structures to comply with state and federal regulatory requirements. The activity also encompasses condition analysis, engineering recommendations, and mandated reports. SCE is required to test, inspect, and report to make sure that the physical condition of facilities and equipment is safe for continued operation, through efforts such as:

- Technical inspection
- Electrical and mechanical engineering
- Civil, structural, and geotechnical engineering
- Construction management and cost engineering
- Performance engineering and testing
- Supervising repairs at Hydro production facilities, structures, and equipment,
- Providing engineering support needed to perform tests and inspections, and prepare reports.
- Applying concrete gunite[32] to repair aged and weather-damaged surfaces of dams and intakes;
- Repacking joints and repairing leaks in steel penstock pipes and flumes;
- Maintaining water-diverting equipment such as valves and spillways; and

[32] ”Gunite” is a mixture of cement, sand, and water applied through a high-pressure hose. It produces a dense, hard layer of concrete, and can be used for lining tunnels or making structural repairs.

- Repairing wood-frame structures appurtenant to Hydro facilities, such as flowline trestles, snow shelter survival cabins, gatehouses, and hydraulic equipment shelters.

C. CM3 – Dam Safety Program

SCE is required to maintain a dam safety program to help ensure that its hydroelectric facilities operate safely.

SCE's Dam Safety Program (DSP) aims to protect life, property, and the environment by making sure that all dams are designed, constructed, operated, and maintained as safely and as effectively as reasonably possible. To accomplish this, SCE must continually inspect, evaluate, and document the design, construction, operation, maintenance, rehabilitation, and emergency preparedness of SCE and key downstream stakeholders. SCE also needs to archive documents concerning the inspections and histories of dams, and the training records for personnel who inspect, evaluate, operate, and maintain them.

These activities are governed by SCE's Owner's Dam Safety Program (ODSP). The ODSP is a FERC-required document that established roles and responsibilities regarding dam safety at SCE, up to and including the President and CEO. SCE's Dam & Public Safety (D&PS) Group, led by the Chief Dam Safety Engineer (CDSE) is responsible for overseeing the operations and strategies that help ensure that SCE's hydro generating facilities operate safely and reliably. Responsibilities include:

- Conducting inspections of dams and supporting inspections by FERC, DSOD and the Part 12D Independent Consultants;
- Evaluating field observations and data collected under the Surveillance and Monitoring Program for each dam;
- Identifying and prioritizing key issues for dams through the Risk Assessment Program, and helping ensure that all data and records pertaining to dam safety are appropriately maintained;
- Providing technical leadership and support to help ensure compliance with the FERC and the California DSOD regulations; and
- Helping ensure that Emergency Action Plans (EAPs) for high-hazard dams are supported by appropriate inundation mapping[33] and analysis of potential failure scenarios. Also, assisting in EAP training and exercises.

[33] "Inundation mapping" generally refers to a map that delineates the area that would be flooded by a particular flood event. It includes the ground surfaces downstream of a dam, showing the probable encroachment by water released because of: (a) failure of a dam, or (b) abnormal flood flows released through a dam's spillway and/or other appurtenant pathways for the water.

The expectations of the Dam Safety Program are prescribed by FERC, which requires Owners to undergo an external audit of their ODSP every five years. SCE also goes beyond FERC's expectations for the ODSP by employing an independent panel of experts titled the Dam Safety Advisory Board (DSAB) to review the Dam Safety Program on an annual basis and to advise on dam safety issues as requested. In addition, for complicated dam safety issues, a Board of Consultants may be convened to opine and advise on issues, and help guide SCE's actions to address those issues.

D. CM4 – External Inspections

SCE's dams are routinely inspected and evaluated by external parties. Inspections are performed by:

1. FERC Division of Dam Safety and Inspections (FERC D2SI). As the federal agency responsible for the safety of hydroelectric projects located on federal lands, FERC D2SI inspects all SCE high-hazard dams annually. SCE personnel accompany the inspector(s) to help ensure the inspector can safely access and observe all relevant features of the dams. The SCE personnel also respond to any questions the inspector may have. Following the inspection, FERC issues a letter documenting the inspection findings, which may include recommending specific repairs, actions or studies. SCE is required by FERC to file a plan and provide a schedule to address these recommendations.
2. California Department of Water Resources, Division of Safety of Dams (DSOD). As the state agency responsible for maintaining the safety of dams in California, DSOD inspects all SCE high-hazard dams annually. SCE personnel accompany the inspector(s) to help ensure they can safely access and observe all relevant features of the dams. The SCE personnel also respond to any questions the inspectors may have. Following the inspection, DSOD issues a report that may include recommendations for specific repairs, actions or studies.
3. Part 12 Independent Consultants. Since 1965, FERC has required, under 18 CFR Part 12, that owners of dams designated as high-hazard, or that meet specified criteria for size, must be evaluated by an Independent Consultant every five years. FERC reviews the credentials and approves every Independent Consultant. The Independent Consultant physically inspects the condition of the dam, and comprehensively evaluates the operating procedures, supporting analyses, and other documentation. The Independent consultant also reviews the Potential Failure Modes Analysis to re-evaluate existing PFMs and identify whether any new PFMs are

needed. The Independent Consultant provides written findings to FERC. This includes stating whether the dam is safe for continued operation, and listing recommendations for repairs, actions or studies. SCE must file a plan and provide a schedule to FERC to address these recommendations.

4. Board of Consultants. FERC has the authority to require that a dam owner retain a Board of Consultants to regularly inspect a specific dam. Currently, only Vermilion Valley Dam (SCE's largest embankment dam) has an established Board of Consultants, who perform annual inspections and issue a report on their findings. While not required by FERC, the design engineers of Vermillion Valley Dam have emphasized that the continued safe operation of the dam depends upon the performance (as assessed by the Board of Consultants) of the dam's complicated drainage system.

E. C1 – Seismic Retrofit

SCE retrofits its dams to increase their capability to withstand seismic loads. SCE performs this activity when it identifies deterioration of the structure, a deficiency in the original design, or an increase in the estimated seismic loads that the dam must withstand.

This work may include rehabilitating and/or replacing concrete, re-compacting and/or replacing embankment materials, installing post-tensioned anchors, and constructing reinforcing elements such as steel braces, concrete buttresses or earthen berms. Some of SCE's dams currently operate under restricted intended reservoir levels, due to potential vulnerability to seismic loading. At these dams, seismic retrofit work may also include making modifications to enhance SCE's ability to maintain these restrictions. Specifically, the work can include lowering the spillway elevation or improving the capacity and/or reliability of the low level outlet works (further discussed in below).

1. Drivers Impacted

This control impacts D1 (Earthquake) by reducing the occurrence of failures due to seismic loading. Please note that this control provides benefit not by reducing the frequency of actual seismic events (which, of course, are outside of SCE's control), but by reducing the Triggered Event Frequency number that springs from seismic events.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

F. C2 – Dam Surface Protection

SCE, along with the previous owners of the SCE dams, have consistently attempted to protect these structures against deterioration by waterproofing the upstream surfaces with methods such as grouting or polysulfide coatings. Since 2006, SCE has found that installing a geomembrane liner system significantly reduces leakage in both concrete and embankment dams. These liners have been installed at seven dams. Installation at an eighth dam is in progress. While many of the high-priority dams have been lined, SCE believes two to three more dams may be candidates for this system in 2019-2023.

1. Drivers Impacted

This control impacts D3 (Failure under Normal Operations) by reducing the leakage through the dam, reducing deterioration at concrete structures, and inhibiting flows through embankment dams that could contribute to internal erosion failures.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

G. C3 – Spillway Remediation and Improvement

SCE repairs and improves the spillways at its dams. This work can include refurbishing deteriorated concrete, installing or improving protective measures (such as water-stops between concrete slabs or drains beneath spillway chutes), rehabilitating or improving spillway gate structures, expanding the spillway or armoring embankment dams to allow them to withstand overtopping of water.

1. Drivers Impacted

This control impacts D2 (Flood) by enhancing the capacity and reliability of dams to safely pass inflows from extreme floods.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

H. C4 – Low Level Outlet (LLO) Improvements

SCE performs LLO repair and improvements for dams. LLOs are systems that can be used to lower the reservoir level of a dam in a controlled manner. In addition to managing water levels during normal operations, LLOs can be used in an emergency to empty the reservoir to prevent or reduce the consequences of dam failure. DSOD has specific requirements regarding the capacity and testing of these systems.

This work can include repairing or replacing valves, gates, gate operators, or constructing a replacement LLO system if the original systems is too costly or difficult to repair.

1. Drivers Impacted

This control is not considered to impact drivers for this risk. Although it is possible that low-level outlets could be utilized to drain a reservoir to prevent a slow-developing failure (occurring over multiple days), there was not sufficient information to credibly model how often this might occur.

2. Outcomes and Consequences Impacted

This control impacts the Safety and Financial consequences of O2 (Hydro Facility Inoperable; Inundation of Unpopulated Areas) and O3 (Hydro Facility Inoperable; Inundation of Unpopulated and Populated Areas) by allowing SCE to partially drain reservoirs in a controlled fashion prior to dam failure to reduce the volume of water in the resulting URRW.

I. C5 – Seepage Mitigation

SCE performs seepage mitigations to reduce the likelihood of initiation and progression of internal erosion in embankment dams. This work can include constructing or rehabilitating drains to reduce seepage, constructing filters to mitigate erosion, and filling sinkholes or joints in the foundation on the upstream side of the dam. Please note that in some cases, reducing seepage from the dam could negatively impact downstream wetlands areas. As a result, SCE may be required under the Clean Water Act to perform compensatory mitigation, which could include restoring a previously existing wetland, enhancing/preserving an existing wetland, or establishing a new wetland.[34] This requirement can be met by purchasing credits from an approved "mitigation bank" as proposed by the US Army Corps of Engineers for their Sacramento River Seepage Mitigation Project.[35] Depending on the circumstances, this requirement could represent a significant portion of the costs.

1. Drivers Impacted

This control impacts Driver D3 (Failure under Normal Operations) by reducing the probability that identified PFMs related to internal erosion will progress to failure.

2. Outcomes and Consequences Impacted

This control is not considered to impact outcomes and consequences.

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[34] "Compensatory Mitigation for Losses of Aquatic Resources; Final Rule." Department of Defense 33 CFR Part 325 and 332, Environmental Protection Agency 40 CFR Part 230. April 10, 2008, *available at* https://www.epa.gov/sites/production/files/2015-03/documents/40_cfr_part_230.pdf

[35] "Sacramento River Seepage Mitigation Project", US Army Corps of Engineers website, *available at* http://www.spk.usace.army.mil/Media/Regulatory-Public-Notices/Article/1531315/spk-2018-00139-sacramento-river-seepage-mitigation-project-yolo-county-ca/

J. C6 – Instrumentation and Communication Improvements

Many SCE dams are in remote locations, and none have permanent on-site dam tenders.[36] However, SCE uses instrumentation to monitor the condition of these dams at centralized Hydro Control Rooms, where an operator is present 24 hours a day. SCE performs work to maintain and improve the capability and reliability of dam instrumentation. This work can consist of repairing, replacing, or installing instruments. Such instruments include reservoir level indicators, flow measurement devices, piezometers[37] and surveillance cameras. The work also encompasses repairing and/or improving the systems that transmit the instrument readings via fiber, radio, and/or satellite to Hydro Control Rooms.

1. Drivers Impacted

This control is not considered to impact drivers for this risk. It is possible that detecting potential failure conditions could allow SCE to intervene to prevent a dam failure from occurring. However, after reasonable inquiry there was insufficient information to credibly model how often this might occur.

2. Outcomes and Consequences Impacted

This control impacts the Safety consequences of O3 (Hydro Facility Inoperable; Inundation of Unpopulated and Populated Areas).

[36] A “dam tender” is the person responsible for daily or routinely operating and maintaining a dam and its appurtenant structures. The dam tender often resides at or near the dam.
[37] Generally speaking, a “piezometer” is an instrument for measuring the pressure of a liquid or gas, or something related to pressure (such as the compressibility of liquid). Piezometers are often placed in boreholes to monitor the pressure or depth of groundwater.

IV. Mitigations

In addition to the controls describe above, SCE has identified additional risk mitigations that could be performed over the 2018-2023 RAMP period.[38] These are shown in Table IV-1.

Table IV-1 – Mitigations

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Reduced	Mitigation Plan		
					Proposed	Alt. #1	Alt. #2
M1	Proactive Dam Removal	All	-	-		x	
M2	Relocation of campgrounds	-	O3	S-I, S-F			x
M3	Purchase of Private Residences	-	O3	S-I, S-F			x

Consequences Abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial – F

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk, and which may continue through the RAMP period.

A. M1 – Proactive Dam Removal

The risk of failure for a dam can never be reduced to zero – unless the dam is removed. Currently, when SCE is considering whether to make significant investment in a given dam, decommissioning is considered as an alternative. SCE could, hypothetically, alter its strategy to consider proactively decommissioning dams to reduce risk. Dam removal is an extensive process that involves: (a) developing a detailed construction plan for safely removing the asset; (b) obtaining all necessary regulatory approvals; (c) performing the work while taking appropriate measures to protect the environment and appropriately dispose of the removed material; (d) remediating the area to a "natural" state in consultation with the appropriate state and federal agencies; and (e) mitigating the impact of dam removal on the downstream community in consultation with all public and private stakeholders.

1. Drivers Impacted

This mitigation impacts D1 (Earthquake), D2 (Flood), and D3 (Failure under Normal Operation) by eliminating all PFMs associated with the removed dams.

2. Outcomes and Consequences Impacted

This mitigation is not considered to impact outcomes and consequences.

[38] The risk-reduction achieved by the mitigations was modeled using input from Subject Matter Experts (SMEs). Please refer to WP Ch. 8, pp. 8.4 – 8.13 *(RAMP Mitigation Reduction Workpaper)* and the supplemental worksheets in its electronic version for details on modeling of controls, and WP Ch. 8, p. 8.14 *(Subject Matter Expert Qualifications)* for qualifications of the participating SMEs.

B. M2 – Relocation of Campgrounds

When many of SCE dams were constructed, the downstream areas were relatively undeveloped. The encroachment of inhabited areas into potential inundation zones is an issue many dam owners face. At many SCE dams, a large portion of the population at risk in a dam failure are located in campgrounds. Relocating these sites could potentially reduce risk.

SCE may be able to accomplish this mitigation by working with the U.S. Forest Service to relocate campsites or campgrounds located within inundation zones. While this work has not been performed before by SCE, there are examples of campgrounds relocated out of flood plains that may serve as a precedent.[39]

1. Drivers Impacted

This mitigation is not considered to impact drivers.

2. Outcomes and Consequences Impacted

This mitigation would reduce the Safety consequences for O3 (Hydro Facility Inoperable; Inundation of Populated and Unpopulated Areas), as it effectively reduces the populated area that could potentially be inundated by a dam failure.

C. M3 – Purchase of Private Residences

Similar to relocating campgrounds, purchasing private residences in the potential inundation zone could reduce the consequences of a dam failure. BC Hydro recently used this strategy to reduce risk for a dam identified as vulnerable to failure if a large earthquake occurs.[40,41]

1. Drivers Impacted

This mitigation is not considered to impact drivers.

2. Outcomes and Consequences Impacted

This mitigation would reduce the Safety consequences for O3 (Hydro Facility Inoperable; Inundation of Populated and Unpopulated Areas). The mitigation would reduce the population that could be inundated by a dam failure.

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[39] "Tucannon Lakes and Floodplain Reconfiguration," Washington Department of Fish & Wildlife, *available at* https://wdfw.wa.gov/lands/wildlife_areas/wt_wooten/floodplain_management/TucannonWootenFactSheet_2015_April.pdf

[40] "BC Hydro Buys Out Properties Below Jordan River Dam." CBC News, May 18, 2016, *available at* https://www.cbc.ca/news/canada/british-columbia/b-c-hydro-jordan-river-1.3585351

[41] "Seismic Hazard at Jordan River", BC Hydro website, *available at* https://www.bchydro.com/energy-in-bc/operations/dam-safety/seismic-hazards/jordan-river-options.html

V. Proposed Plan

SCE has evaluated the mitigations and controls in Sections III and IV and developed a proposed plan of risk-reduction activities to pursue, summarized in Table V-1, below.

Table V-1 – Proposed Plan

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Retrofit	2018	2023	$ 7.4	$ -	0.0152	0.0021	0.0496	0.0067
C2	Dam Surface Protection	2018	2023	$ 0.6	$ -	0.0002	0.0004	0.0007	0.0013
C3	Spillway Remediation and Improvement	2018	2022	$ 12.0	$ -	0.4235	0.0353	1.3884	0.1157
C4	Low Level Outlet Improvements	2018	2023	$ 13.4	$ -	0.0150	0.0011	0.0492	0.0037
C5	Seepage Mitigation	2019	2022	$ 10.5	$ -	0.0356	0.0034	0.1173	0.0112
C6	Instrumentation / Communication Enhancements	2018	2021	$ 6.4	$ -	0.6020	0.0937	1.8679	0.2909
			Total - Proposed Plan	**$ 50.2**	**$ -**	**1.0915**	**0.0217**	**3.4732**	**0.0692**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

A. Overview

SCE's proposed plan includes capital maintenance and refurbishment projects including C1 (Seismic Retrofit), C2 (Dam Surface Protection), C3 (Spillway Remediation and Improvement), C4 (Low Level Outlet Improvements), C5 (Seepage Mitigation), and C6 (Instrumentation and Communication Improvements). This work is a continuation of SCE's efforts to responsibly manage the risk associated with its high-hazard dams.

B. Execution Feasibility

Although SCE expects to be able to execute the amount of work contemplated in this Proposed Plan, executing on the proposed capital projects can be impacted by the need to obtain approvals, given the large number of agencies involved. A project may require approvals from FERC, DSOD, U.S. Forest Service, California Department of Fish & Wildlife, California Water Quality Board, regional water quality control boards, California State Historic Preservation Officer, local air quality districts, and/or others. Some of these approvers will have competing requirements and interests.

Another factor that impacts the execution schedule of the projects is the short construction window for many dams. Most construction projects for dams at higher elevations cannot begin until June or July, due to snow conditions. The end of the working season for many sites is typically early November, but early storms can shut down projects as early as October. This can cause projects to extend by one to two years.

C. Affordability

SCE believes the proposed controls are an appropriate investment in maintaining the safety of its dams, many of which have been in operation since the early 20th century. While the baseline risk is the lowest among the nine risks scored for RAMP, the proposed portfolio is estimated to reduce this risk by approximately 23%. This 23% figure is incremental to the risk already reduced through required compliance activities.

This Proposed Plan, especially C3 (Spillway Remediation and Improvement) and C5 (Seepage Mitigation), will address the top risks within SCE's portfolio of dams identified through this RAMP analysis, as well as SCE's existing Dam Safety Risk Assessment Program. By improving the instrumentation and communication systems, including deploying surveillance cameras in C6 (Instrumentation and Communication Improvements), we expect to significantly improve our ability to identify potential dam failures and, where necessary, activate Emergency Activation Plans to notify downstream stakeholders. When the USBR analyzed historical dam failures, the USBR concluded that adequate warnings reduced fatalities by more than ten times compared to cases where no warning was provided.[42]

Some of the proposed controls have relatively low RSE, but are still recommended as they provide other benefits. While C2 (Dam Surface Protection) does not significantly reduce risk, installing these liners slows deterioration and extends the useful life of the dams. Similarly, C4 (Low Level Outlet Improvements) enhances SCEs ability to manage water for normal operation and maintenance activities.

D. Other Considerations

Projects that require draining or substantially lowering the reservoir levels can face challenges with competing water management needs. In high runoff years, it may be difficult to safely release or store the water elsewhere. In low water years, draining a reservoir may negatively impact SCE's ability to meet its obligations to other water users and meet minimum flows required to protect aquatic species and riparian habitats.

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[42] RCEM – Reclamation Consequence Estimating Methodology, Interim Guidelines for Estimating Life Loss for Dam Safety Risk Analysis." U.S. Bureau of Reclamation, July 2015, *available at* http://www.usbr.gov/ssle/damsafety/documents/RCEM-Methodology.pdf

VI. Alternative Plan #1

SCE has evaluated the mitigations and controls in Sections III and IV and developed an alternative plan for reducing risk, as summarized in Table VI-1.

Table VI-1 – Alternative Mitigation Plan #1

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Retrofit	2018	2023	$ 7.4	$ -	0.0147	0.0020	0.0472	0.0064
C2	Dam Surface Protection	2018	2023	$ 0.6	$ -	0.0002	0.0004	0.0007	0.0012
C3	Spillway Remediation and Improvement	2018	2022	$ 12.0	$ -	0.3353	0.0279	1.0691	0.0891
C4	Low Level Outlet Improvements	2018	2023	$ 13.4	$ -	0.0150	0.0011	0.0500	0.0037
C5	Seepage Mitigation	2019	2022	$ 10.5	$ -	0.0317	0.0030	0.1014	0.0097
C6	Instrumentation / Communication Enhancements	2018	2021	$ 6.4	$ -	0.5974	0.0930	1.8842	0.2934
M1	Proactive Dam Removal	2020	2023	$ 145.0	$ -	0.2276	0.0016	0.7393	0.0051
			Total - Alternative Plan #1	**$ 195.2**	**$ -**	**1.2221**	**0.0063**	**3.8919**	**0.0199**

A. Overview

This alternative mitigation plan includes all of the controls contemplated in the Proposed Plan (C1 through C6), and also considers reducing risk associated with specific dams by removing them altogether through M1 (Proactive Dam Removal). The risk of failure for a dam can never be reduced to zero – unless the dam is removed.

B. Execution feasibility

SCE's ability to execute the projects in this plan is subject to the time required to obtain the necessary approvals (e.g., DSOD and FERC permitting approval) to begin the work, particularly for M1 (Proactive Dam Removal).

For the purposes of RAMP, SCE has selected three dams associated with small hydroelectric plants that could, in theory, be decommissioned within the time period 2018-2023.

C. Affordability

Initial estimates show that removing the three dams considered in M1 (Proactive Dam Removal) could potentially cost tens of millions of dollars, when factoring in the remote location and the need to perform environmental restoration activities. Alternative Plan #1 provides 12% greater risk reduction than the Proposed Plan. However, the RSE is significantly less efficient (71% worse) than the Proposed Plan due to the high projected costs of decommissioning. Consequently, SCE believes its current controls represent a more cost-effective method of managing risk.

While decommissioning these three dams does not appear to be a cost-effective tool for managing safety risks, SCE's small hydro facilities are facing other economic challenges. SCE anticipates there will be instances in the foreseeable future where the decommissioning of some small hydro facilities, including removal of the associated dams, may be the best course of action. These challenges include the costs to relicense these assets with FERC (likely including reduced electricity generation and other costs to comply with the new licenses), other regulatory and energy market changes, and long-term shifts in precipitation and snowpack due to climate change.

SCE's hydro fleet includes 22 small hydro powerhouses with a total capacity of 95 MW. These small hydro assets entered service between 1893 and 1929. The FERC licenses for 16 of these small powerhouses expire during 2021 year to 2023 year. While appreciable capital refurbishment and improvement has been made over the assets' lives as necessary, much of this infrastructure is original equipment; significant additional refurbishment would be needed if operations are to continue for several more decades.[43]

It is foreseeable that continued negative changes in powerhouse economics could cause SCE to sell, or retire and decommission, certain of the SCE small Hydro assets, rather than complete their upcoming FERC relicensing and make the associated significant capital investments necessary to continue to operate the assets. The impacts of relicensing on small Hydro powerhouse economics will not be known until further progress is made with relicensing. SCE also continues to assess and quantify capital refurbishment needed to continue asset operation for the assumed 40-year duration of a new license. Once these economic factors are known, SCE will be in a better position to forecast which SCE small Hydro assets (if any) might be sold, or retired and decommissioned, rather than relicensed for continued operation for decades into the future.

Decommissioning any of these assets, including associated dam removal projects, will require a large amount of capital to execute. In our 2021 GRC, SCE may propose initiating base rate recovery of the forecast future costs to decommission a portion of SCE's small hydro assets. This reflects SCE's expectation that decommissioning could help address safety risks and

[43] For example, new licenses might include an increase in the "minimum stream release" required at the stream diversion site for the powerhouse (i.e., the location where water is diverted from the stream for conveyance to the powerhouse). For most powerhouses, the powerhouse water discharge is returned to the native stream-bed several miles downstream from where it was diverted. The minimum stream release establishes the flow rate in the native stream bed between the diversion point and the return point. An increase in "minimum stream release" reduces the amount of stream flow diverted to the powerhouse, and therefore reduces the amount of electricity otherwise generated. Powerhouse economics can be negatively affected as a result.

other challenges impacting the cost-effectiveness of small hydro. Incorporating a reasonable level of small hydro decommissioning costs into our GRC forecast will also help ensure that customers who currently benefit from a hydroelectric asset pay a share of whatever costs will eventually be required to remove that asset.

D. Other Considerations

Removing the dams will require extensive discussion with stakeholders, particularly agencies that hold the land the dams are located on, such US Forest Service and National Park Service). These actions will also require either an amendment or surrender of the FERC license for the project, which will allow other stakeholders to raise their concerns.

Removing a dam can also have indirect impacts, such as loss of recreation areas, impacts to water management, and potential economic impacts to the local community. All of these indirect impacts would need to be considered, and quantified where possible.

VII. Alternative Plan #2

SCE has evaluated the mitigations and controls in Sections III and IV and developed a second alternative plan for risk-reduction activities, summarized in Table VII-1.

Table VII-1 – Alternative Mitigation Plan #2

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Seismic Retrofit	2018	2023	$ 7.4	$ -	0.0152	0.0021	0.0497	0.0067
C2	Dam Surface Protection	2018	2023	$ 0.6	$ -	0.0002	0.0004	0.0007	0.0013
C3	Spillway Remediation and Improvement	2018	2022	$ 12.0	$ -	0.4248	0.0354	1.3935	0.1161
C4	Low Level Outlet Improvements	2018	2023	$ 13.4	$ -	0.0147	0.0011	0.0483	0.0036
C5	Seepage Mitigation	2019	2022	$ 10.5	$ -	0.0357	0.0034	0.1177	0.0112
C6	Instrumentation / Communication Enhancements	2018	2021	$ 6.4	$ -	0.5845	0.0910	1.8162	0.2828
M2	Relocation of campgrounds	2022	2023	$ 5.0	$ -	0.0405	0.0081	0.1243	0.0249
M3	Purchase of Private Residences	2021	2023	$ 3.0	$ -	0.0064	0.0021	0.0195	0.0065
			Total - Alternative Plan #2	**$ 58.2**	**$ -**	**1.1221**	**0.0193**	**3.5699**	**0.0613**

A. Overview

When many of SCE's dams were constructed, the downstream areas were relatively undeveloped. Many dam owners face the issue of inhabited areas expanding into or encroaching upon potential inundation zones.

SCE has identified two potential avenues to mitigate this situation: (1) working with the U.S. Forest Service to relocate campsites or campgrounds located within inundation zones; and (2) directly purchasing private residences located in potential inundation zones.

Under this alternative mitigation plan, SCE would pursue all controls identified under the proposed plan (C1 through C6). In addition, SCE would reduce the exposure of populated areas to Uncontrolled Rapid Release of Water from a dam failure. SCE would do so by pursuing M2 (Relocation of Campgrounds) and M3 (Purchase of Private Residences).

B. Execution Feasibility

SCE is confident in its ability to execute the physical work involved in the proposed capital maintenance projects.

SCE has relatively low confidence in its ability to relocate campgrounds and acquire private residences. Success in these endeavors would largely be outside of SCE's control, and would reside mainly in the hands of outside parties.

There is an upcoming opportunity to discuss relocating campsites and campgrounds, because several SCE projects will be going through relicensing in the near future. The

relicensing process is a natural forum for discussing these issues with the Forest Service and other stakeholders. We do not know whether the Forest Service would be amenable to this proposal; many of the campgrounds and campsites that would be most beneficial to relocate are also among the most popular.

While purchasing private residences is conceptually simple, success is highly dependent on the willingness of individuals to sell. When BC Hydro implemented this mitigation, they were able to acquire 10 of 11 properties in the potential inundation zone, but encountered one owner who was unwilling to sell.[44]

C. Affordability

Initial evaluation shows that if the relocation and acquisition mitigations can be executed, they would have costs similar to those of major capital projects. SCE has often been required to build and/or fund the construction of campsites as part of the terms of its FERC licenses. The cost can be millions of dollars per campground, particularly if new sanitary or parking facilities are required. An initial evaluation of ten houses in the potential inundation zone of one dam found that they had estimated values ranging from $300,000 to $600,000. Assuming that SCE would need to pay above-market value to motivate owners to sell, the cost for a single dam could be in the millions.

The risk reduction for Alternative Plan #2 is 3% greater than the proposed plan. But the RSE for Alternative Plan #2 is 11% lower than the Proposed Plan. While there is not strong justification to include these mitigations in the current proposed plan, there may be situations identified in the future where relocating or acquiring facilities would be the most cost-effective option to mitigate risk. SCE will evaluate these options on a case-by-case basis.

D. Other Constraints

As discussed, these mitigations are almost entirely dependent on the willingness of the parties owning the potentially inundated facilities to engage.

[44] "The Last Man in Jordan River." Times Colonist, February 26, 2017. http://www.timescolonist.com/islander/the-last-man-in-jordan-river-1.10445193

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

SCE has identified capital projects over the 2018-2023 period that will reduce the risk of dam failure. However, the risk reduction potential is small compared to controls and mitigations identified in other RAMP risk chapters. This highlights a challenge many dam owners have experienced when trying to integrate dams into their Enterprise Risk Management programs: balancing management of frequently-occurring risks against very rare risks with catastrophic consequences.

B. Data Collection & Availability

One of the challenges associated with this RAMP chapter is that there is no direct data on failure rates to draw from. This is because SCE has not experienced a dam failure comparable to those discussed in this chapter. SCE's existing Dam Safety Risk Assessment program provided a reasonable starting point for the RAMP risk analysis, given the lack of direct historical data. This assessment is informed by analysis and information obtained to date. The analysis and data are examined in facilitated workshop settings that include SCE Operations and Dam Safety personnel, outside consulting experts, and engineers from FERC and DSOD.

SCE's pilot project currently being performed under the FERC RIDM Guidelines may offer a potential path to improving risk estimates through a combination of field investigations and additional numerical simulations. While this approach is expensive and time-consuming, it could be a viable option for assessing the top dam safety risks.

Additionally, SCE is completing its most recent update of Potential Failure Modes under the Part 12 process in 2018. The new failure modes developed reflect the latest guidance on developing effective PFMS, including lessons learned from the 2017 Oroville Spillway failure. SCE will be re-evaluating its dam safety risks under the new PFMs. The overall portfolio risk is not expected to change substantially, but the new PFMs are more granular and should allow for better mapping to control and mitigation projects to develop better assessments of RSE.

C. Potential Impact of Oroville Spillway Incident in Northern California

In 2017, the failure of the Oroville spillway failure was a highly significant event for the entire dam safety industry. The summary of the Independent Forensic Team (IFT) report concludes by stating:

> *"Although the practice of dam safety has certainly improved since the 1970s, the fact that this incident happened to the owner of the tallest dam in the*

United States, under regulation of a federal agency, with repeated evaluation by reputable outside consultants, in a state with a leading dam safety regulatory program, is a wake-up call for everyone involved in dam safety. Challenging current assumptions on what constitutes 'best practice' in our industry is overdue."[45]

The IFT identified physical factors that contributed to the incident, such as unrecognized design deficiencies, unrecognized poor foundation conditions, and repeated ineffective repairs. SCE personnel involved in dam safety have discussed these factors and used them as a cautionary point of reference when evaluating potential dam safety issues. The IFT also identified contributing organizational factors, such as lack of awareness of dam safety issues at the highest levels of DWR. SCE has implemented measures to foster such awareness, including annual briefings to the President, CEO, and other officers of the Company by the Chief Dam Safety Engineer and the Dam Safety Advisory Board. The first of these briefings occurred in February 2018.

The Oroville incident has resulted in calls for reform of both state and federal dam safety programs. Following this event, the California legislature passed two bills (SB-92 and AB-1270) related to dam safety that Governor Brown signed into law. SB-92 established additional requirements for emergency action plans and inundation mapping for dams. AB-1270 established additional requirements for inspecting dams, and also directed DSOD to "propose amendments to its dam safety inspection and reevaluation protocols to incorporate updated best practices, including risk management, to ensure public safety" by January 1, 2019.

The Oroville incident also led to a request to the Government Accountability Office to perform an audit of FERC Department of Dam Safety and Inspections, and a self-initiated external audit of FERC by a panel of Dam Safety experts. Findings from these audits have not yet been released.

Optimistically, changes to state and federal regulations would incorporate a greater use of risk-informed decision making, so that SCE is better able to prioritize and address dam safety concerns. It is possible that regulations will focus on compliance with standards-based approaches that do not consider risk. This could lead to a substantial increase in dam safety investments without a corresponding significant reduction in risk. It is even possible that risks might increase, because if SCE must undertake a large number of compliance-driven projects

[45] "Independent Forensic Team Report, Oroville Dam Spillway Incident." January 5, 2018, p. S-3, *available at* https://damsafety.org/sites/default/files/files/Independent%20Forensic%20Team%20Report%20Final%2001-05-18.pdf

that address relatively low risk issues, that might hamper SCE's ability to execute projects that actually mitigate its top dam safety risks.

D. Performance Metrics

SCE currently tracks the following metrics related to dam safety:

- Number of high-hazard dam failures
- Number of Emergency Action Plan Activations
- DSOD Dam Condition Ratings (Note: FERC does not share its condition ratings)

SCE also evaluates a number of operational metrics pertaining to normal operations and dam safety, such as reservoir levels, stream flows, leakage measurements, and snowpack. Collectively, these data help us maintain safe and reliable dams. However, no single metric has been identified that provides a concise, meaningful measure of the safety of Hydro Assets. SCE will continue to evaluate and manage risk through our Dam Safety Risk Assessment Program.

Technical Appendix:
Hydro Asset Safety
Long-Term Risk Analysis Pilot

SOUTHERN CALIFORNIA EDISON®
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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Technical Appendix
Hydro Asset Safety – Long-Term Risk Analysis Pilot

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

SCE's RAMP report analyzes key risks from 2018 through 2023. This time period allows for an understanding of how each risk grows, and how each control or mitigation can affect that risk, in the near-term. However, limiting the analysis to this six-year period does not capture the potential costs and benefits of risk controls and mitigations that extend beyond 2023.

SCE has prepared this technical appendix to the Hydro Asset Safety chapter to pilot an analytical approach for a longer-term risk analysis. SCE selected Hydro Asset Safety as the pilot for this alternative approach, due to the long-lived nature of many of its risk controls and mitigations.[1] SCE presents this analysis not to endorse any particular method of analyzing long-term risks, but simply as a means to test and evaluate the application of the concept.[2] In this technical appendix, SCE uses the same bowtie components, controls, and mitigations that were evaluated in the short-term analysis.

In the sections that follow, SCE explains how the drivers and outcomes in the Hydro Asset Safety risk bowtie were revisited to consider their behavior over a 40-year period. We also explain how we revisited the controls and mitigations in Hydro Asset Safety to model a full lifespan of costs and benefits (up to a 40-year maximum).

As described below, taking a longer-term view of risk analysis does not add an unreasonable degree of technical complexity. However, it requires significant judgment to estimate useful lives, forecast asset degradation through decades, estimate driver frequency far into the future, and select (or not select) discount rates to account for uncertainty and to present-value the benefits (financial and otherwise) and costs to the present.[3]

This analysis found that, even under multiple discount rate scenarios, risk reduction activities consistently show higher Risk Spend Efficiency values in this long-term analysis compared to the analysis under the standard RAMP period of 2018-2023. For example, the Proposed Plan in this technical analysis has an RSE of 0.16 (using the 0% discount rate),

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[1] This type of approach could potentially be used for other controls and mitigations in other chapters.

[2] The proposed S-MAP Settlement, includes provisions aimed at considering methodologies for evaluating the full impact of controls and mitigations over their useful lives.

[3] Accordingly, certain dollar figures, estimates of years, and other numbers in our analysis necessarily reflect substantial judgment, and are included for illustrative purposes.

compared to only 0.03 under the standard RAMP period. These results indicate that the full value and benefits of risk controls and mitigations that offer long-lived usefulness may not be captured under the standard RAMP analysis approach.

B. Long-Term Risk Analysis

The RAMP risk evaluation framework used in the nine RAMP chapters can be extended to evaluate effects beyond 2023. The probabilistic risk model can be modified relatively easily from a technical modeling standpoint. But the more challenging aspect of performing this long-term analysis is developing the model input parameters to account for potential changes over long periods of time. These key inputs parameters include:

- Determination of growth of unmitigated risk over time. For example, a driver frequency may be reasonably modeled as constant over a six-year period, but could change substantially over decades.
- Rate of escalation to use for costs and financial consequences;
- Method and discount rate to apply to all risk reduction benefits (safety, reliability, financial);
- Effectiveness of controls / mitigations over time, and incorporation of any associated estimates of asset degradation;
- Changes in uncertainty bounds over time.[4]

Input parameters for the various controls and mitigations must also reflect the expected "durability" of the risk-reduction benefits. That is, over what period of time is an investment considered to be reducing risk. The risk reduction benefit of an inspection might extend for a few years, while the benefit of a structural modification might last decades. In some cases, adjusting operations or removing a particular hazard might reduce risk permanently.

C. Evaluation of Long Term Risk Results

In financial cost-benefit analyses, the common practice is to discount future costs and benefits to reflect the fact that an amount of money invested today could be invested and (on average) earn a rate of return, and would therefore provide higher worth than the same amount of money in the future.

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[4] Uncertainty in this analysis is captured in the probabilistic distributions for consequences (for example, the standard deviation for a normal distribution could increase over time to capture fluctuations in population).

Social discounting[5] is practiced by government agencies such as the EPA,[6] and is also generally applied to financial costs and benefits. There is no established practice for discounting benefits of non-financial metrics, such as injuries or fatalities.

To examine the potential impact of discounting on risk analyses, SCE has evaluated the long-term risk analysis results presented in this chapter considering discount rates of 0%, 5% and 10% to risk reduction benefits expressed in MARS units. This exercise is illustrative, and SCE makes no claim that any of these values are appropriate for use in future RAMP filings. Table I-1 shows summary results on a mean basis.[7]

[5] "Social discounting" takes into account what benefits society as a whole, rather than what benefits an individual, a group of individuals, or an organization.

[6] "Guidelines for Preparing Economic Analyses, Chapter 6: Discounting Future Benefits and Costs." National Center for Environmental Economics, Environmental Protection Agency, December 17, 2010.

[7] SCE shows results on a mean basis in this table solely to simplify the discussion; tail-average results are also considered, but omitted from this table for simplicity.

Table I-1 – Summary of Long-Term Risk Analysis Results

Inventory of Controls & Mitigations			Mitigation Plan		
ID	**Name**		**Proposed**	**Alternative #1**	**Alternative #2**
C1	Seismic Retrofit		x	x	x
C2	Dam Surface Protection		x	x	x
C3	Spillway Remediation and Improvement		x	x	x
C4	Low Level Outlet Improvement		x	x	x
C5	Seepage Mitigation		x	x	x
C6	Instrumentation and Communication Improvements		x	x	x
M1	Proactive Dam Removal			x	
M2	Relocation of Campgrounds				x
M3	Purchase of Private Residences				x
	Cost Forecast ($ Million)		$50.2	$195.2	$58.2
Mean (MARS)	*Baseline*	*6 years*	4.64	4.64	4.64
	Risk	*40 years*	36.27	36.27	36.27
	Risk Reduction (MRR)	*6 years*	1.09	1.22	1.12
		40 years (0% discount)	8.04	14.20	8.94
		40 years (5% discount)	5.07	7.91	5.50
		40 years (10% discount)	3.81	5.48	4.08
	Risk Spend Efficiency (RSE)	*6 years*	0.02	0.01	0.02
		40 years (0% discount)	0.16	0.07	0.15
		40 years (5% discount)	0.10	0.04	0.09
		40 years (10% discount)	0.08	0.03	0.07

6 year period is 2018-2023
40 year period is 2018-2057

II. Long-Term Risk Analysis for Hydro Asset Safety

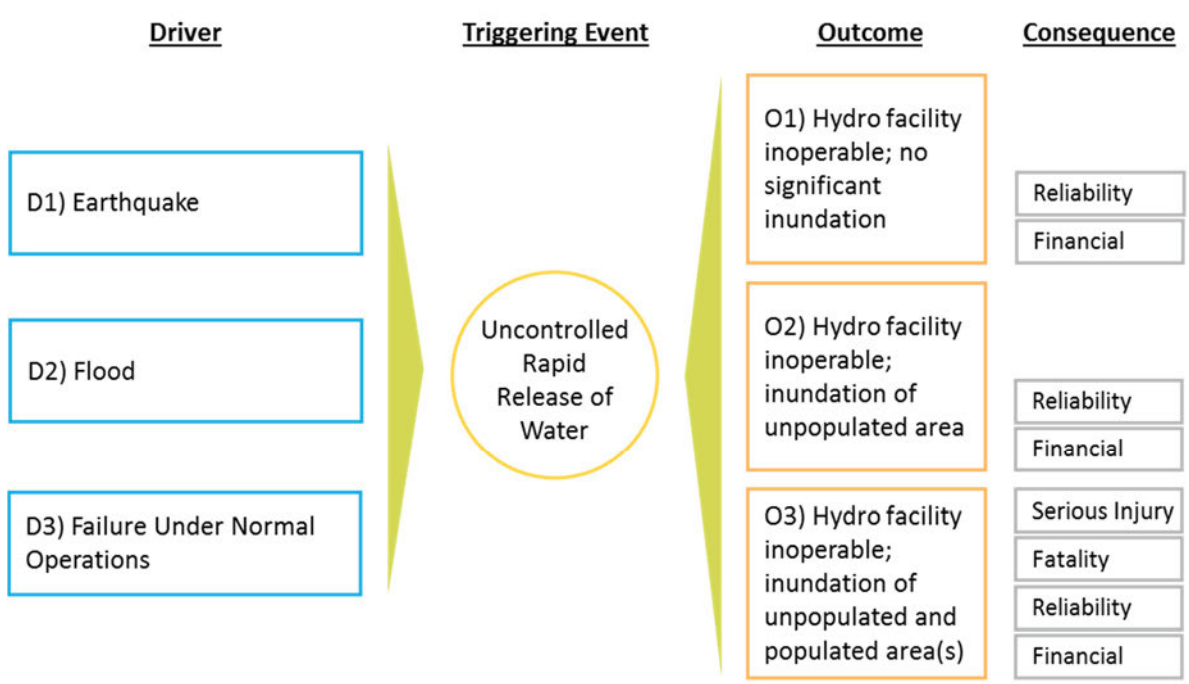
A. Background

Chapter 8 – Hydro Asset Safety analyzes the risk posed by SCE's hydro assets, current actions taken to manage the risk, and mitigation plans to address the risk from 2018-2023. To demonstrate how analysis over a longer time period might be performed, SCE extended the analysis to 2057, for a total duration of 40 years. This section discusses how the inputs to the RAMP model were modified for the long-term analysis.[8]

B. Risk Bowtie

SCE used the Hydro Asset Safety Risk bowtie shown below in Figure II-1. No changes were made to the bowtie for the long-term analysis.

Figure II-1 – Hydro Asset Safety Risk Bowtie



C. Driver Analysis

SCE has identified three drivers (Earthquake; Flood; Failure Under Normal Operations) that could lead to the uncontrolled and rapid release of water. Over the period 2018-2023, the

[8] See Chapter 8, Section II for a detailed discussion of the baseline risk for Hydro Asset Safety.

frequency of these drivers is held constant. SCE believes this is appropriate. However, over a 40-year period, SCE believes it is possible that the driver frequencies may change significantly. The section discusses how these changes were modeled for purposes of the long-term analysis.

1. D1 – Earthquake

Patterns of seismic activity shift over time. But these changes occur over temporal scales of hundreds or thousands of years. However, as dams age they could potentially become more vulnerable to earthquakes. For purposes of this exercise, SCE assumes an exponential annual growth[9] in driver frequency of 2% starting in 2024. The baseline annual frequency of this driver grows from 0.0027 (1 in 370 years) in 2023 to 0.0053 (1 in 189 years) by 2057.

2. D2 – Flood

The frequency and magnitude of extreme floods will be impacted by climate change. SCE has commissioned studies to evaluate the potential impact on its dams and found that under the range of climate scenarios considered,[10] the frequency of floods that could threaten the safety of SCE dams could increase by a factor of 30%, or decrease by a factor of 50%.

Additionally, aging of a dam could potentially increase the vulnerability to failure from severe flooding. For purposes of this exercise, SCE assumes an exponential annual growth in driver frequency of 2%, starting in 2024. The baseline annual frequency of this driver grows from 0.0024 (1 in 416 years) in 2023 to 0.0053 (1 in 213 years) by 2057.

3. D3 – Failure under Normal Operations

The frequency of failures under Normal Operations may increase with age without periodic major capital refurbishment. There is insufficient data to develop a trend. For purposes of this exercise, SCE assumes an exponential annual growth in driver frequency of 2% starting in 2024. The baseline annual frequency of this driver grows from 0.0006 (1 in 1,667 years) in 2023 to 0.0012 (1 in 833 years) by 2057.

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[9] Exponential growth occurs when the rate of change of a value is proportional to that value. Mathematically, if a parameter has a value x_0 in year 0 and grows exponentially with rate r, then the value in year T will be $x_0(1 + r)^T$.

[10] Two scenarios were selected to "bound" a suite of 234 global climate change model projections from the Coupled Model Intercomparison Project Phase 5 (CMIP5) collection. The "hot-dry" scenario uses the 10th-percentile change in precipitation and a 90th percentile change in temperature. The "warm-wet" scenario uses the 90th-percentile change in precipitation and the 10th-percentile change in temperature.

D. Triggering Event - Uncontrolled Rapid Release of Water

SCE defines the Triggering Event as the Uncontrolled Rapid Release of Water (URRW) from a Hydro High-Hazard Dam. No changes to the event definition are required for the long-term analysis.

E. Outcomes

We include the same outcomes and associated probabilities of occurrence in this technical analysis as we presented in Chapter 8. Outcome likelihoods are assumed for this exercise to remain constant over time.[11]

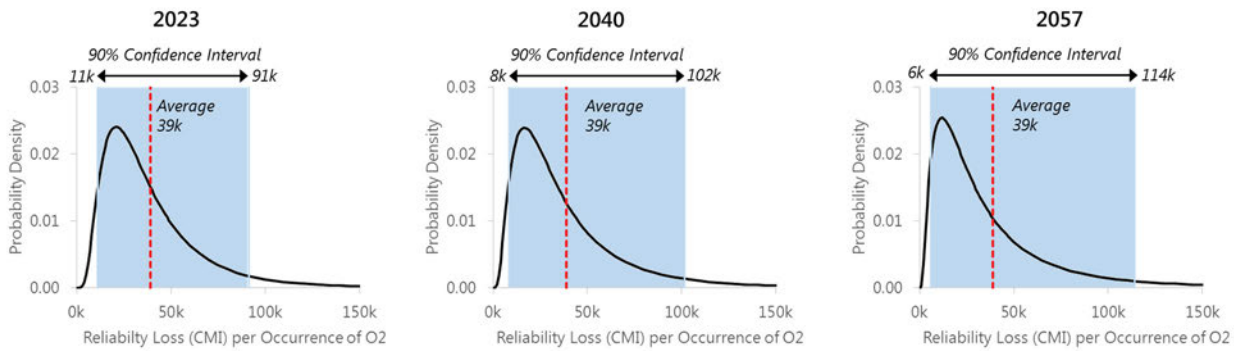
The parameters of the consequence distributions for each outcome are modeled as constant over the 2018-2023 period. Starting in 2024, these parameters are adjusted to reflect possible changes in consequences over time.

In some cases there may be an expectation that the consequences of an outcome will change over time, but there may be insufficient information to determine whether that change will result in an increase or decrease. For example, reliability impacts scale with the local population. It is reasonable to expect that population will change over 40 years, but in some areas it may not be possible to determine if it will grow or shrink. SCE has chosen to model this by holding the average of the distribution constant and increasing the uncertainty of the distribution over time, as shown in Figure II-2. The average of the distribution remains fixed, but the uncertainty, as measured by the 90% confidence interval,[12] increases by approximately 30% from 2023 to 2057.

[11] SCE chose to keep the outcome likelihood percentages constant over time to reduce complexity in this analysis. However, it is plausible, and perhaps likely, that a comprehensive analysis would yield changes in annual outcome likelihood values that would have to be justified and modeled.

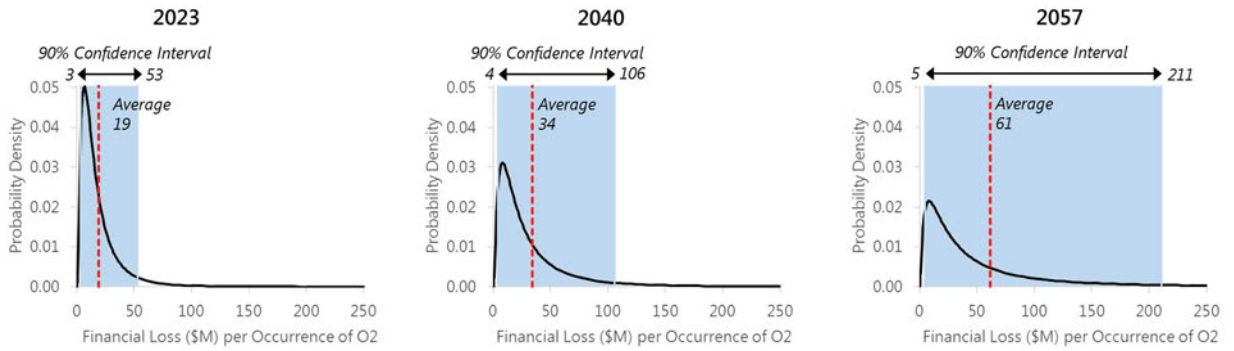
[12] The 90% confidence interval is defined as the range between 5th- and 95th-percentile values of a distribution. It is expected that 90% of the samples drawn from a distribution will fall within this range.

Figure II-2 – Evolution of a Reliability Consequence Distribution over Time



In addition to growing uncertainty over time, there may be baseline trends that will increase or decrease consequences over time. For example, financial losses for an event that occurs 20 years in the future will almost certainly be greater than those for an identical event that occurs today, as cost for materials and labor rise over time. SCE has chosen to model this by increasing both the average and the uncertainty of the distribution, as shown in Figure II-3.

Figure II-3 – Evolution of a Financial Consequence Distribution over Time



1. O1 – Hydro Facility Inoperable; No Significant Inundation

Outcome O1 can result in Reliability consequences due to unavailability of Hydro Plants and Financial consequences due to lost generation. Over time, the population in the areas served by SCE Hydro Plants may increase or decrease, which would result in a corresponding increase or decrease in Reliability impacts. For purposes of this exercise, this is represented by increasing the uncertainty of the consequence distribution over time. Specifically, the standard deviation of the distribution for Reliability consequences is modeled

with exponential annual growth of 1%, starting in 2024. The mean of the distribution is held constant.

Similarly, the value of the generation provided by SCE Hydro Plants may increase or decrease. For purposes of this exercise, the standard deviation of the distribution for Financial consequences is modeled with exponential annual growth of 1%, starting in 2024. The mean of the distribution is held constant.

2. O2 – Hydro Facility Inoperable; Inundation of Unpopulated Area

Outcome O2 can result in Reliability consequences due to unavailability of Hydro Plants and Financial consequences due to lost generation and costs to remediate damage caused by inundation.

As for Outcome O1, the uncertainties of the consequence distributions are modeled as increasing over time. For purposes of this exercise, the standard deviations of the distributions for Reliability and Financial consequences are modeled with exponential annual growth of 1%, starting in 2024.The mean of the distribution for Reliability is held constant, but the cost of construction activities to remediate inundation damage is expected to escalate over time. Consequently, the mean of the distribution for Financial is modeled with exponential annual growth of 3.5%, starting in 2024.

3. O3 – Hydro Facility Inoperable; Inundation of Unpopulated and Populated Area(s)

Outcome O3 can result in Safety consequences due to inundation of populated areas, Reliability consequences due to unavailability of Hydro Plants and possible inundation damage to the local electrical system, and Financial consequences due to lost generation and costs to remediate damage caused by inundation.

Similar to Outcomes O1 and O2, the uncertainties of the consequence distributions are modeled as increasing over time. For purposes of this exercise, the standard deviations of the distributions for Serious Injury, Fatality, Reliability and Financial consequences are modeled with exponential annual growth of 1%, starting in 2024. The means of the distributions for Serious Injury, Fatality and Reliability are held constant. Similar to Outcome O2, the mean of the distribution for Financial is modeled with an exponential annual growth of 3.5%, starting in 2024, to represent the expected escalation in the cost for construction activities needed to remediate inundation damage.

III. Compliance & Controls

This section discusses how the modeling of the controls has been modified for the long-term analysis.[13]

As was done in the Hydro Safety Asset chapter, compliance activities (CM1-CM4) are not risk modeled in this technical appendix. The remaining controls consist of hydro capital maintenance refurbishment and/or replacement activities (C1-C6), all of which are capital investments necessary for maintaining dam infrastructure and equipment.[14] The useful life of the various types of investments may vary. For example, concrete or earth reinforcement of a dam could provide benefit for several decades, while a surveillance camera is likely to need replacement after 10 years.

For this exercise, SCE models each family of controls as having a "design life." A design life is a period over which the investment provides the full intended risk-reduction benefit. Once the age of the control equals the design life, the benefit is modeled as degrading linearly over time until the age of the control reaches twice the design life. At that point, the control is modeled to be fully ineffective. Note that is different from the modeled depreciation of the asset.[15]

To illustrate how this is modeled, please consider a hypothetical control C0 with a total mitigation effectiveness of 30% and a Design Life of 10 years. C0 is implemented in three "phases" over years 1-3, with each phase assumed to provide 10% mitigation effectiveness. As shown in Figure III-1, the full mitigation effectiveness is reached in year 3. The first "phase" reaches the end of its design life at year 11 and begins to degrade starting in year 12, with the second and third phases following, until the control is completely ineffective in year 23.

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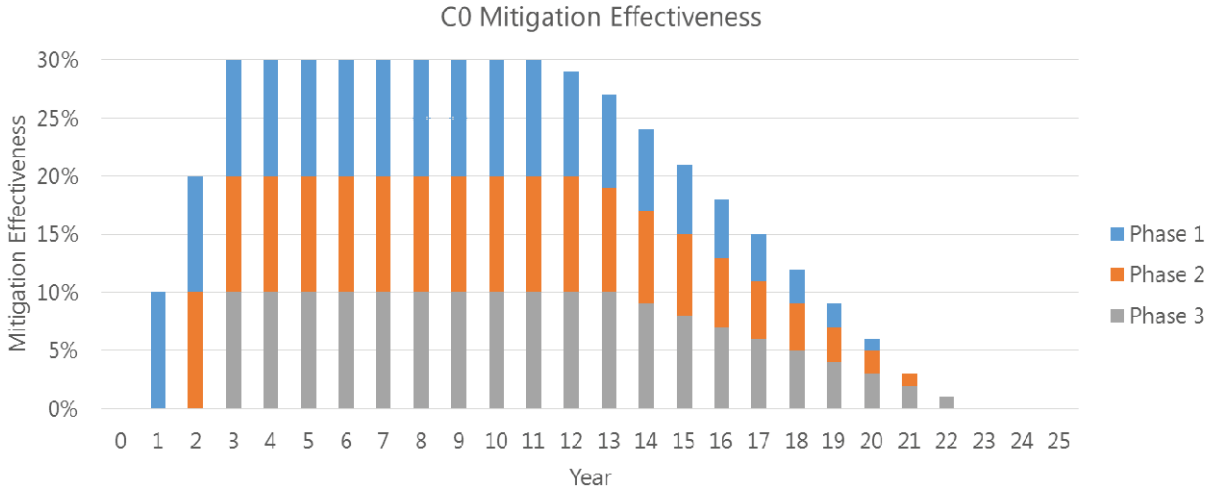
[13] See Chapter 8, Section III for a detailed discussion of Compliance & Control activities for Hydro Asset Safety.

[14] This analysis assumed that ongoing capital-related expenses pertaining to the controls and mitigations evaluated are *de minimis*.

[15] "Design life" is used for purposes of this illustrative analysis. To the extent SCE deploys this long-term risk assessment methodology for broader risk analysis in the future, SCE will need to work with stakeholders to identify the appropriate design life parameters to use. For example, this could mean aligning to asset depreciation schedules or other accounting principles.

Figure III-1 – Long-Term Control Effectiveness Model



A. C1 – Seismic Retrofit

This work may include rehabilitating and/or replacing concrete, re-compacting and/or replacing embankment materials, installing post-tensioned anchors, and constructing reinforcing elements such as steel braces, concrete buttresses or earthen berms.

Due to the durable nature of the materials involved, these modifications are considered to be relatively long-lived. The reductions to D1 (Earthquake) are modeled with a design life of 30 years.

B. C2 – Dam Surface Protection

SCE, along with the previous owners of the SCE dams, have consistently attempted to protect these structures against deterioration by waterproofing the upstream surfaces with methods such as grouting or polysulfide coatings.

The manufacturer of the liner cites cases where installations have been in service for 30 years. However, SCE dams are located in environments that may shorten the effective life-span, due to large swings in temperature between winter and summer, and prolonged periods of direct exposure to sunlight (which degrades the plastic geomembrane). The reductions to D3 (Failure Under Normal Operations) are modeled with a design life of 20 years.

C. C3 – Spillway Remediation and Improvement

SCE repairs and improves the spillways at its dams. This work can include refurbishing deteriorated concrete, installing or improving protective measures (such as water-stops between concrete slabs or drains beneath spillway chutes), rehabilitating or improving spillway gate structures, expanding the spillway, or armoring embankment dams to allow them to withstand overtopping of water.

Due to the durable nature of the materials involved, these modifications are considered to be relatively long-lived. The reductions to D2 (Flood) are modeled with a design life of 30 years.

D. C4 – Low Level Outlet (LLO) Improvements

SCE performs LLO repair and improvements for dams. LLOs are systems that can be used to lower the reservoir level of a dam in a controlled manner. In addition to managing water levels during normal operations, LLOs can be used in an emergency to empty the reservoir to prevent or reduce the consequences of dam failure.

The materials involved (concrete and steel) are durable in nature of the materials involved, but some components of the system (valves, valve operators, seals) may be more vulnerable to deterioration. The reductions to D2 (Flood) are modeled with a design life of 20 years.

E. C5 – Seepage Mitigation

SCE performs seepage mitigations to reduce the likelihood of initiation and progression of internal erosion in embankment dams. This work can include constructing or rehabilitating drains to reduce seepage, constructing filters to mitigate erosion, and filling sinkholes or joints in the foundation on the upstream side of the dam.

The materials involved (earth and rockfill) are durable in nature, but will be likely be continuously subjected to seepage which could degrade the mitigation effectiveness over time. The reductions to D3 (Failure Under Normal Operations) are modeled with a design life of 20 years.

F. C6 – Instrumentation and Communication Improvements

Many SCE dams are in remote locations. SCE uses instrumentation to monitor the condition of these dams at centralized Hydro Control Rooms, where an operator is present 24 hours a day. SCE performs work to maintain and improve the capability and reliability of dam instrumentation. This work can consist of repairing, replacing, or installing instruments. The

work also encompasses repairing and/or improving the systems that transmit the instrument readings via fiber, radio, and/or satellite to Hydro Control Rooms.

The electronic systems involved are designed with consideration of the environmental challenges at SCE dam sites, however, they are likely to be short-lived compared to structural improvements. The reductions to the Safety impacts of Outcome O3 (Hydro facility inoperable; inundation of populated and unpopulated areas) are modeled with a design life of 10 years.

IV. Mitigations

In addition to the controls describe above, SCE identified additional risk mitigations that could be performed over the 2018-2023 RAMP period. This section discusses how the modeling of these programs and processes has been modified for the long-term analysis.[16]

A. M1 – Proactive Dam Removal

During the normal course of managing its portfolio of dams, SCE evaluates situations where decommissioning may be the appropriate *reactive* measure to an emergent dam safety issue. SCE could, hypothetically, alter its strategy to consider *proactively* decommissioning dams to reduce risk. This mitigation contemplates the proactive removal of dams, which includes mitigating the impacts of dam removal on the environment and any additional flooding that might occur downstream due to the removal of a dam.

As this mitigation involves the permanent removal of a dam, the modeled reductions to D1 (Earthquake), D2 (Flood) and D3 (Failure Under Normal Operations) do not degrade with time.

B. M2 – Relocation of Campgrounds

At many SCE dams, a large portion of the population at risk in a dam failure are located in campgrounds. Relocation of these sites could potentially reduce risk. SCE may be able to accomplish this mitigation by working with the U.S. Forest Service to relocate campsites or campgrounds located within inundation zones.

As this mitigation involves the permanent relocation of populated areas, the modeled reductions to the Safety impacts of O3 (Hydro facility inoperable; inundation of populated and unpopulated areas) do not degrade with time.

C. M3 – Purchase of Private Residences

Similar to the relocation of campgrounds, by purchasing private residences in the potential inundation zone, SCE could reduce the consequences of a dam failure.

As this mitigation involves the permanent removal of populated residences, the modeled reductions to the Safety impacts of O3 (Hydro facility inoperable; inundation of populated and unpopulated areas) do not degrade with time.

[16] See Chapter 8, Section IV for a detailed discussion of Mitigation activities for Hydro Asset Safety.

V. Proposed Mitigation Plan

SCE evaluated the Proposed Plan of risk-reduction activities from the Hydro Asset Safety chapter, which consisted of controls C1 through C6. The results of the long-term analysis of the Proposed Plan are shown below in Table V-1 on a mean basis, and in Table V-2 on a tail average basis.

Table V-1 – Proposed Plan Long-Term Analysis Results (Mean)

ID	Name	Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.02	0.18	0.09	0.05	0.00	0.03	0.01	0.01
C2	Dam Surface Protection	0.6	20	0.0002	0.0018	0.0010	0.0006	0.0004	0.0038	0.0022	0.0016
C3	Spillway Remediation and Impovement	12.0	30	0.42	4.13	1.98	1.19	0.04	0.38	0.20	0.13
C4	Low Level Outlet Improvements	13.4	20	0.015	0.111	0.061	0.039	0.001	0.009	0.006	0.004
C5	Seepage Mitigation	10.5	20	0.04	0.32	0.17	0.11	0.00	0.03	0.02	0.01
C6	Instrumentation & Communication Improvements	6.4	10	0.60	2.21	1.68	1.33	0.09	0.44	0.35	0.30
	Total - Proposed Plan	**50.2**	**-**	**1.09**	**6.95**	**3.98**	**2.72**	**0.02**	**0.16**	**0.10**	**0.08**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Table V-2 – Proposed Plan Long-Term Analysis Results (Tail Average)

ID	Name	Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.05	0.60	0.29	0.17	0.01	0.09	0.05	0.03
C2	Dam Surface Protection	0.6	20	0.0007	0.0060	0.0032	0.0021	0.0013	0.0122	0.0072	0.0051
C3	Spillway Remediation and Impovement	12.0	30	1.39	13.47	6.43	3.83	0.12	1.24	0.65	0.44
C4	Low Level Outlet Improvements	13.4	20	0.05	0.36	0.20	0.13	0.00	0.03	0.02	0.01
C5	Seepage Mitigation	10.5	20	0.12	1.04	0.56	0.36	0.01	0.11	0.06	0.05
C6	Instrumentation & Communication Improvements	6.4	10	1.87	6.99	5.30	4.21	0.29	1.38	1.12	0.95
	Total - Proposed Plan	**50.2**	**-**	**3.47**	**22.47**	**12.77**	**8.70**	**0.07**	**0.52**	**0.32**	**0.24**

All of the controls provide greater total risk reduction benefits outside of the RAMP time period (2018-2023) than within it, regardless of discount rate used. This is especially pronounced for controls with longer design lives, such as C3 (Spillway Remediation and Improvement), where the MRR from 2024-2057 (with 0% discount rate) is approximately ten times the MRR over the period from 2018-2023. In contrast, C6 (Instrumentation & Communication Improvements), has the highest MRR over the period from 2018-2023 but captures only four times more benefit over the 2024-2057 (with 0% discount rate). This is because the benefits are less “durable.”

The long-term risk analysis also highlights a change in the RSE scores. For example, the tail average RSE for C6 increases from 0.29 over the 2018-2023 period to 1.38 when measured over 40 years (a factor of 5). In contrast, the RSE for C3 increases from 0.12 to 1.24 (a factor of 10).

In this example, the ranking of mitigations based on RSE does not change between the near-term and long-term analyses. This is partly due to the fact that these controls are asset-based capital programs with longer design lives. As we can see from these results and how the MRR and RSE can change based on the design life of the control, we can envision situations where the relative MRR and RSE of short-term and long-term controls and mitigation may be significantly influenced by the time window of the analysis.

VI. Alternative Mitigation Plan #1

SCE evaluated Alternative Plan #1 as designed in the Hydro Asset Safety chapter, which consists of the control activities of the Proposed Plan (C1 through C6) and adds M1 (Proactive Dam Removal). The results of the long term-analysis of Alternative Plan #1 are shown below in Table VI-1 on a mean basis, and Table VI-2 on a tail-average basis.

Table VI-1 – Alternative Plan #1 Long-Term Analysis Results (Mean)

ID	Name	Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.01	0.17	0.08	0.05	0.00	0.03	0.01	0.01
C2	Dam Surface Protection	0.6	20	0.0002	0.0017	0.0009	0.0006	0.0004	0.0035	0.0020	0.0014
C3	Spillway Remediation and Impovement	12.0	30	0.34	3.83	1.82	1.08	0.03	0.35	0.18	0.12
C4	Low Level Outlet Improvements	13.4	20	0.02	0.10	0.06	0.04	0.00	0.01	0.01	0.00
C5	Seepage Mitigation	10.5	20	0.03	0.29	0.16	0.10	0.00	0.03	0.02	0.01
C6	Instrumentation & Communication Improvements	6.4	10	0.60	2.00	1.51	1.20	0.09	0.40	0.33	0.28
M1	Proactive Dam Removal	145.0	Permanent	0.23	6.58	3.07	1.80	0.00	0.05	0.02	0.01
	Total - Alternative Plan #1	**195.2**	**-**	**1.22**	**12.98**	**6.69**	**4.26**	**0.01**	**0.07**	**0.04**	**0.03**

Table VI-2 – Alternative Plan #1 Long-Term Analysis Results (Tail Average)

ID		Cost ($M)	Design Life (years)	MRR 2018-2023	MRR 2024-2057 w/ Discount Rate: 0%	5%	10%	RSE 2018-2023	RSE 2018-2057 w/ Discount Rate: 0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.05	0.55	0.26	0.15	0.01	0.08	0.04	0.03
C2	Dam Surface Protection	0.6	20	0.0007	0.0055	0.0029	0.0019	0.0012	0.0112	0.0065	0.0046
C3	Spillway Remediation and Impovement	12.0	30	1.07	12.45	5.88	3.48	0.09	1.13	0.58	0.38
C4	Low Level Outlet Improvements	13.4	20	0.05	0.33	0.18	0.11	0.00	0.03	0.02	0.01
C5	Seepage Mitigation	10.5	20	0.10	0.95	0.51	0.32	0.01	0.10	0.06	0.04
C6	Instrumentation & Communication Improvements	6.4	10	1.88	6.31	4.78	3.79	0.29	1.28	1.04	0.88
M1	Proactive Dam Removal	145.0	Permanent	0.74	21.43	9.94	5.82	0.01	0.15	0.07	0.05
	Total - Alternative Plan #1	**195.2**	**-**	**3.89**	**42.04**	**21.55**	**13.69**	**0.02**	**0.24**	**0.13**	**0.09**

The long-term analysis shows that M1 provides large risk-reduction benefits over the period from 2024-2057. This is due in large part because the nature of the mitigation (dam removal) means the risk-reductions are permanent and do not degrade with age. The tail average RSE of M1 jumps from 0.01 over 2018-2023 to 0.15 when considering the period from 2018-2057. This increase in RSE relative to the increases in the controls indicates that capturing the long-term benefits of mitigations could potentially change the mitigations we select.

In this case, even though Alternative Plan #1 (with 0% discount rate) provides nearly twice the tail average MRR of the Proposed Plan over 2018-2057 (45.93 versus 25.94, respectively), the tail average RSE of Alternative Plan #1 (again, with 0% discount rate) is still 54% less than the Proposed Plan (0.24 versus 0.52, respectively). This is largely due to the high cost of M1 (Proactive Dam Removal), which is included in Alternative Plan #1 and not in the Proposed Plan.

Applying a discount rate of 5% reduces the tail average MRR of Alternative Plan #1 over the 2018-2057 period by 45%. The MRR is even further reduced when a discount rate of 10% is applied; however, it still remains many times higher than the MRR of this plan over the 2018-2023 period.

Using a 5% discount rate, the tail average RSE of Alternative Plan #1 is about 59% less than the Proposed Plan. Based on the initial results, using discount rates significantly affects the RSE of all controls and mitigations. These rates affect can have a greater effect on longer-lived activities.

VII. Alternative Mitigation Plan #2

SCE evaluated Alternative Plan #2 as designed in the Hydro Asset Safety chapter, which consists of the control activities of the Proposed Plan (C1 through C6) and adds M2 (Relocation of Campgrounds) and M3 (Purchase of Private Residences). The results of the long term-analysis of Alternative Plan #2 are shown below in Table VII-1 on a mean basis, and in Table VII-2 on a tail average basis.

Table VII-1 – Alternative Plan #2 Long-Term Analysis Results (Mean)

ID	Name	Cost	Design Life	MRR	MRR 2024-2057 w/ Discount Rate:			RSE	RSE 2018-2057 w/ Discount Rate:		
		($M)	(years)	2018-2023	0%	5%	10%	2018-2023	0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.02	0.18	0.08	0.05	0.00	0.03	0.01	0.01
C2	Dam Surface Protection	0.6	20	0.0002	0.0018	0.0010	0.0006	0.0004	0.0036	0.0021	0.0015
C3	Spillway Remediation and Impovement	12.0	30	0.42	3.96	1.90	1.14	0.04	0.37	0.19	0.13
C4	Low Level Outlet Improvements	13.4	20	0.01	0.11	0.06	0.04	0.00	0.01	0.01	0.00
C5	Seepage Mitigation	10.5	20	0.04	0.31	0.17	0.11	0.00	0.03	0.02	0.01
C6	Instrumentation & Communication Improvements	6.4	10	0.58	2.13	1.61	1.28	0.09	0.42	0.34	0.29
M2	Relocation of Campgrounds	5.0	Permanent	0.04	1.03	0.50	0.31	0.01	0.21	0.11	0.07
M3	Purchase of Private Residences	3.0	Permanent	0.01	0.12	0.06	0.04	0.00	0.04	0.02	0.01
	Total - Alternative Plan #2	**58.2**	**-**	**1.12**	**7.82**	**4.38**	**2.96**	**0.02**	**0.15**	**0.09**	**0.07**

Table VII-2 – Alternative Plan #2 Long-Term Analysis Results (Tail Average)

ID		Cost	Design Life	MRR	MRR 2024-2057 w/ Discount Rate:			RSE	RSE 2018-2057 w/ Discount Rate:		
		($M)	(years)	2018-2023	0%	5%	10%	2018-2023	0%	5%	10%
C1	Seismic Retrofit	7.4	30	0.05	0.58	0.27	0.16	0.02	0.08	0.04	0.03
C2	Dam Surface Protection	0.6	20	0.0007	0.0057	0.0031	0.0020	0.0041	0.0118	0.0070	0.0049
C3	Spillway Remediation and Impovement	12.0	30	1.39	12.93	6.17	3.69	0.35	1.19	0.63	0.42
C4	Low Level Outlet Improvements	13.4	20	0.05	0.35	0.19	0.12	0.01	0.03	0.02	0.01
C5	Seepage Mitigation	10.5	20	0.12	1.00	0.54	0.34	0.03	0.11	0.06	0.04
C6	Instrumentation & Communication Improvements	6.4	10	1.82	6.72	5.10	4.05	0.91	1.33	1.08	0.91
M2	Relocation of Campgrounds	5.0	Permanent	0.12	3.85	1.82	1.08	0.08	0.80	0.39	0.24
M3	Purchase of Private Residences	3.0	Permanent	0.02	0.44	0.21	0.13	0.02	0.15	0.08	0.05
	Total - Alternative Plan #2	**58.2**	**-**	**3.57**	**25.87**	**14.30**	**9.58**	**0.06**	**0.51**	**0.31**	**0.23**

The long-term analysis shows that M2 (Relocation of Campgrounds) and M3 (Purchase of Private Residences) provide significant risk-reduction benefits over the period from 2024-2057. By removing population from potentially threatened areas, the risk-reductions become permanent and do not degrade with time. The tail-average RSE (using a 0% discount rate) for M2 and M3 increase by factors of nine and eight, respectively, when considering a 40-year period instead of a 6-year period. Alternative Plan #2 (using a 0% discount rate) provides 13% greater tail average MRR compared to the Proposed Plan over 2018-2057 (29.44 versus 25.94, respectively). The tail average RSE of Alternative Plan #2 over the same period (again, using a 0% discount rate) is only 2% less than the Proposed Plan (0.51 versus 0.52, respectively).

Applying a discount rate of 5% reduces the tail average MRR of Alternative Plan #2 over the 2018-2057 period by 39%. The MRR is even further reduced when a discount rate of 10% is applied; however, it still remains many times higher than the MRR of this plan over the 2018-2023 period.

Consistent with the results from the Proposed Plan and Alternative Plan #2, these preliminary results show that consideration the time period and use of discounting can significantly affect the calculated risk reduction benefits and risk spend efficiency for mitigations. The selected time period and discount rate could potentially alter the relative RSE ranking of short- and long-lived mitigations.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

The long-term analysis demonstrates that, from a technical modeling perspective, the RAMP framework used in SCE's report can be modified to account for longer-time frames. The selection of input parameters for these long-term analyses should consider potential changes in driver frequency, consequences, and the durability or longevity of the risk-reduction benefits from controls and mitigations.

A long-term analysis may significantly change the calculated MRR and RSE for individual mitigations and controls as well as the MRR and RSE for mitigation plans. In the particular example presented here, with the assumptions used in the analysis, the relative "ranking" by RSE of the Proposed and Alternative Plans did not change. However, a different risk or a different set of assumptions could result in a scenario where the ranking of plans differs based on the time period selected for analysis. This is expected to be especially true when evaluating controls and mitigations with shorter design lives.

The use of discounting of future benefits significantly reduces the MRR from long-lived controls and mitigations. However, in this particularly example, the effect of discounting on RSE was relatively small.

This technical analysis evaluated controls that are funded by capital costs. Applying this framework to short-lived O&M-funded mitigations would require the consideration of ongoing O&M costs, and the presumed ongoing execution of those mitigations over the life of the analysis.

B. Next Steps

SCE appreciates the opportunity to present this illustrative longer-term analysis. We look forward to further dialogue with, and feedback from, the Commission and parties on how we can address many of the considerations raised in this technical appendix in future iterations of RAMP.

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Physical Security

Chapter 9

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

SCE's main objective is to safely provide reliable, affordable, and clean electricity to our customers. The physical safety of our workforce, customers, facilities, assets, and equipment is a critical component of this responsibility. The threat landscape that SCE and other electric utilities face is diverse – threats range from simple acts of theft to coordinated attacks on the electric grid.

This chapter evaluates the physical security of our facilities, and the risks posed to the people and assets in those facilities. In this RAMP chapter we define physical security consistent with related Commission efforts: physical security encompasses those elements and strategies directly involved in physical protection, such as implementing perimeter walls and fencing, lighting, cameras, and conducting security patrols.[1]

We build on this basic definition by adding a broader set of activities. These activities (in combination with the right processes, procedures and training) help us deter, monitor, and mitigate attempts to compromise SCE's facilities, equipment, or people in those facilities.

In this chapter SCE quantifies the physical security risk, and assesses how to mitigate physical security threats. SCE identified two primary threats that can compromise SCE's physical security:

- Third party breaching the security perimeter due to security system bypass/breach, human error, or process failure;
- An insider (e.g., an SCE employee or authorized contractor) using their access or knowledge with malicious intent.

[1] Brinkman, Ben; Chen, Connie; O'Donnell, Arthur; Parkes, Chris. (2012, February.) Regulation of Physical Security for the Electric Distribution System. *California Public Utilities Commission.* Retrieved from www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454097 Whitepaper to discuss regulatory framework around electric distribution system physical security, including process and methodology recommendations for CPUC.

This chapter analyzes incidents occurring within the perimeter of our facilities that result in theft, trespassing, workplace violence, or a coordinated attack targeting multiple substations.[2]

SCE identified a number of compliance activities, controls, and new mitigations to address this risk.

- This chapter describes two compliance activities related to the North American Electric Reliability Corporation (NERC):[3] NERC CIP-014 (CM1) and NERC CIP-003-V6 (CM2). These activities protect the bulk electric system (BES) operations from security incidents.

This chapter evaluates four controls:[4]

- Grid Infrastructure Protection Base (C1a) & Enhanced (C1b): This includes activities to protect our electric grid from multiple physical threats;
- Protection of Generation Capabilities (C2): This includes activities to protect our generation facilities;
- Non-Electric Facilities - Protection of Major Business Functions Base (C3a) & Enhanced (C3b): This includes activities to protect our major business functions and administrative facilities;
- Asset Protection (C4): This includes employing security officers at our facilities, performing background checks, and implementing security training to our workers.

Finally, this chapter evaluates five mitigations:[5]

- Insider Threat program enhancements (M1a & M1b): Two options to improve the protection of our assets, our workers, and the public against insider threat.
- Smart Key Program (M2, M3, M4): A phased approach to replace conventional lock-and-key devices with Smart Key technology.
    - Phase 1 (M2): Limited population;
    - Phase 2 (M3): Expanded to remaining electrical facilities;
    - Phase 3 (M4): Expanded to remaining business function facilities.

SCE has developed three risk mitigation plans:

---

[2] All of SCE's facilities are in scope, including, for example: office buildings, substations, switching centers, grid control centers, data centers, electricity generation facilities, IT facilities, warehouses, and service centers.
[3] CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
[4] C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.
[5] M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report, and are addressed in Section IV.

- The Proposed Plan continues existing programs (C2 & C4), proposes the enhanced version of current controls (C1b & C3b), improves our current Insider Threat program (M1a), and rolls out the initial phase of the Smart Key Program (M2).

- Alternative Plan #1 continues existing programs (C2 & C4), proposes the enhanced version of current controls (C1b & C3b), improves our current Insider Threat program with the enhanced version (M1b), and rolls out all three phases of the Smart Key Program (M2, M3, & M4).

- Alternative Plan #2 continues existing programs (C2 & C4), continues existing base level controls (C1a & C3a) and adds the same incremental efforts as the Proposed Plan to improve our current Insider Threat program (M1a).

B. Scope

The scope of this chapter is defined in Table I-1 below.

Table I-1 – Chapter Scope

IN SCOPE	• Acts that occur within the security perimeter of SCE facilities that are protected by physical security measures. Facilities in-scope include office buildings, substations, switching centers, grid control centers, data centers, electricity generation facilities, IT facilities, warehouses, and service centers.
OUT OF SCOPE	• Acts that occur beyond the security perimeter of SCE facilities. Potential examples include: incidents related to power lines, poles and transmission towers; or incidents occurring when SCE field workers perform work on or around a customer's property.[6] • Public safety incidents resulting from criminal activity that occurs as a result of the public's unauthorized interactions with SCE's electric and/or non-electric assets. For example, serious injury to an individual from contacting energized equipment while engaged in attempted theft, whether such attempt occurs inside or outside the physical security perimeter of SCE facilities.

[6] There are no reasonable and substantial physical security measures to protect assets that are located beyond SCE facilities.

C. Summary Results

In this chapter, SCE identifies the primary drivers and outcomes of physical security threats, and outlines the physical security controls and mitigations that are most effective in limiting SCE's exposure to those threats. Table I-2 summarizes this chapter's baseline risk analysis, controls, and contemplated mitigations, and gives portfolio results that we project over the 2018 – 2023 period.

Table I-2 – Summary of Results (Annual Average Over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1a	Grid Infrastructure Protection - Base			X
C1b	Grid Infrastructure Protection - Enhanced	X	X	
C2	Protection of Generation Capabilities	X	X	X
C3a	Non-electric Facilities/Protection of Major Business Functions - Base			X
C3b	Non-Electric Facilities/Protection of Major Business Functions - Enhanced	X	X	
C4	Asset Protection	X	X	X
M1a	Insider Threat Program Enhancement & Information Analysis - Base	X		X
M1b	Insider Threat Program Enhancement & Information Analysis - Enhanced		X	
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	X	X	
M3	Smart Key Program Phase 2 - Electrical Sites		X	
M4	Smart Key Program Phase 3 - Remaining Non Electric Sites		X	
Mean (MARS)	*Cost Forecast ($ Million)*	$64.60	$71.32	$54.70
	Baseline Risk	3.67	3.67	3.67
	Risk Reduction (MRR)	1.77	2.04	1.40
	Residual Risk	1.90	1.64	2.27
	Risk Spend Efficiency (RSE)	0.027	0.029	0.026
Tail Average (MARS)	*Cost Forecast ($ Million)*	$64.60	$71.32	$54.70
	Baseline Risk	14.16	14.16	14.16
	Risk Reduction (MRR)	6.98	8.05	5.52
	Residual Risk	7.19	6.11	8.64
	Risk Spend Efficiency (RSE)	0.108	0.113	0.101

Figures represent 2018 - 2023 annual averages.

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

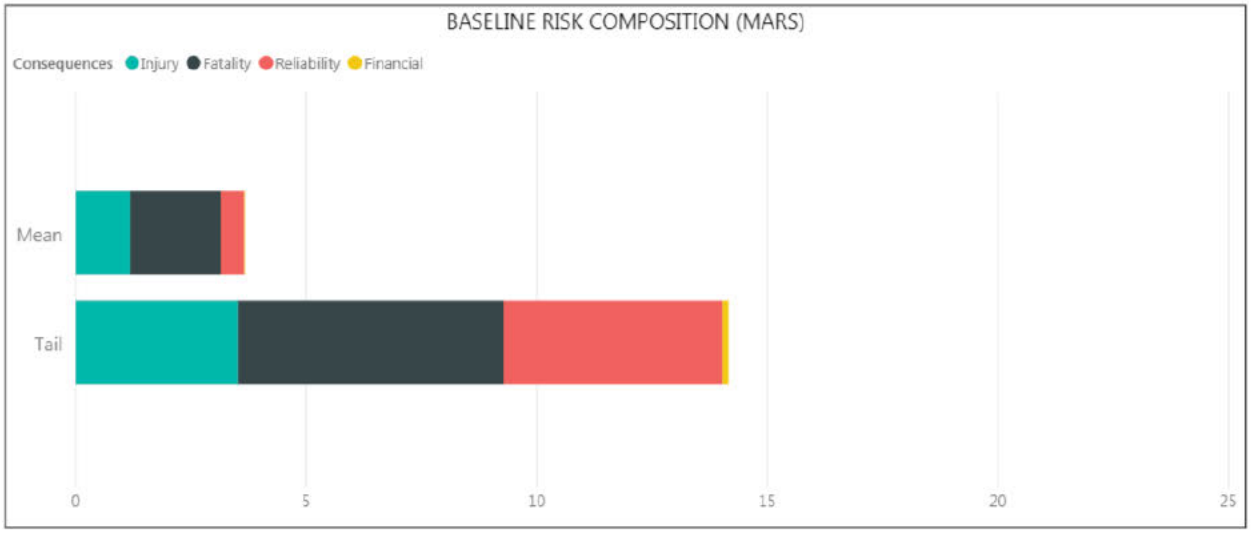
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 illustrates the composition of consequences within the baseline risk. This figure shows that on a mean basis, the majority of risk is associated with safety consequences.

On a tail-average basis, safety still predominates as a consequence for this risk. However, reliability significantly increases in impact. This is due to the low-likelihood, high-consequence impacts of Outcome 4 (Coordinated Attack on Multiple Substations), which results in significant reliability impacts.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS score is 100.

D. Sensitive, Confidential Information Must Be Protected

SCE may be unable to share information beyond a certain level of detail to protect sensitive and confidential security data. Exposing detail about SCE's security protocols could compromise the integrity and secrecy of our physical security approach, and enable an attacker to avoid or defeat the security safeguards.

This chapter discloses information in a manner that does not compromise SCE's physical security. To promote transparency and help stakeholders access additional and sensitive information that might be necessary to answer specific questions, SCE can provide an in-person briefing, or take other reasonable measures to convey information as appropriate.

II. Risk Assessment

A. Background

SCE maintains operations at many different facilities throughout our service territory. Each facility has various assets that require different levels of security protection – e.g., electrical equipment, communication technology, vehicles, workers, etc. The physical security needs of each facility can be unique. For example, a high-impact[7] facility, such as a 500 kV transmission substation, requires aggressive physical security (e.g., gated entry, cameras, gunshot detection, etc.). If SCE's substations and/or their associated primary control centers are rendered inoperable or damaged as the result of a security breach, it will compromise our ability to safely and reliably deliver power to our customers. The National Research Council has noted that a carefully planned and executed attack could "deny large regions of the country access to bulk system power for weeks or even months."[8]

In contrast, a low-impact[9] facility, such as a laydown yard that houses material inventory for ongoing work, may require fewer controls. Moreover, office buildings require different levels of security based on the criticality, occupancy level, and sensitivity of operations that occur at each location.

[7] SCE categorizes SCE's BES facilities under California Independent System Operator (ISO) control as Tier 1, Tier 2, Tier 3 and Tier 4. Each tier has associated physical security requirements based on criticality and impact to the BES. High-impact facilities are those categorized as Tier 1-3 sites, or identified in the annual business impact analysis as being critical to the BES or to primary SCE business functions, or having high impact on the community.

[8] National Research Council (2012). Terrorism and the Electric Power Delivery System. Washington, DC: The National Academies Press. https://doi.org/10.17226/12050, Retrieved from http://www.nap.edu/catalog/12050/terrorism-and-the-electric-power-delivery-system. This is a study completed by several organizations on the impact of coordinated attacks on the power grid. It discusses vulnerability based on several factors, and examines potential effects on the economy and the health/welfare of society.

[9] For physical security purposes, low-impact facilities are simply defined as those not meeting the criteria of a high-impact facility.

B. Physical Security Threats to Electric Utilities

The internal and external threats facing the utility industry continue to evolve. Between 2011 and 2014, electric utilities reported to the U.S. Department of Energy a total of 348 physical attacks that caused outages or other power disturbances.[10]

California has experienced several major incidents in the past, including harm to individuals. A few example are listed below:

- In 1997, insider sabotage[11] resulted in a three-and-a-half hour power outage in San Francisco that affected 126,000 customers.
- In 2011, an SCE employee shot and killed two SCE managers, and wounded an SCE employee and a contract worker before committing suicide. This incident occurred at a secure SCE facility located in a gated complex equipped with card access readers.[12]
- In 2013, unknown attackers unleashed a coordinated attack on PG&E's Metcalf substation in northern California. The attackers severed six underground fiber-optic lines before firing more than 100 rounds of ammunition at the substation's transformers, causing more than $15 million in damage. The intentional act of sabotage, likely involving more than one gunman, differed from any previous attack on the nation's grid in its scale and sophistication.[13] Metcalf substation is located in a highly concentrated area and supplies electricity to Silicon Valley.

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[10] Reilly, Steve. (2015, March 24.) "Bracing for a Big Power Grid Attack: 'One Is Too Many.'" *USA Today*. Retrieved from https://www.usatoday.com/story/news/2015/03/24/power-grid-physical-and-cyber-attacks-concern-security-experts/24892471/ This newspaper article highlights the frequency of attacks on the power grid and potential risks. It documents several specific physical and cyber-attacks.

[11] Egan, Timothy. (1997, October 24.) "Blackout in San Francisco; Sabotage Is Seen." *New York Times.* Retrieved from https://www.nytimes.com/1997/10/25/us/blackout-in-san-francisco-sabotage-is-seen.html This newspaper article reviews the sabotage at a PG&E facility that caused a substantial power outage in San Francisco.

[12] Khan, Irfan and Becerra, Hector. (2011, December 17.) Edison Office Shooting Victims, Killer Identified. *Los Angeles Times.* Retrieved from http://articles.latimes.com/2011/dec/17/local/la-me-shooting-follow-20111218 This newspaper article discusses a workplace violence incident at SCE's Irwindale facility.

[13] Reilly, Steve. (2015, March 24.) "Bracing for a Big Power Grid Attack: 'One is too Many.'" *USA Today*. Retrieved https://www.usatoday.com/story/news/2015/03/24/power-grid-physical-and-cyber-attacks-concern-security-experts/24892471/ This newspaper article highlights the frequency of attacks on the power grid and potential risks. It documents several specific physical and cyber-attacks.

- Between 2015 and 2017, there were two reported safety incidents where intruders either suffered serious injury or fatality within SCE substations.[14]
- Moreover, the former Secretary of the Department of Homeland Security (Michael Chertoff) predicted a future attack in the U.S. that would exceed the sophistication and resulting damage of Metcalf, including the possibility of a combined physical and cyberattack.[15]

These examples illustrate the types of physical security threats this chapter evaluates. We have used the RAMP process as an opportunity to re-examine SCE's security strategy. The complexity and volume of physical threats facing SCE require an array of security mitigation measures to detect, deter, delay, disrupt, and respond to threats and hazards.[16]

Thus, SCE's controls and mitigations provide a layered approach to help ensure the safety and security of SCE workers, visitors, facilities, assets, and equipment. A layered approach refers to multiple security measures implemented at different levels throughout the facility, to help provide "pancaked" layers of protection. In other words, the perimeter is the first line of defense, the exterior of the building is the second line, and the interior of the building is the third line. A layered approach reduces the risk of unauthorized users gaining physical access to restricted areas. We describe this approach in more detail in Section V - Proposed Plan.

C. Risk Bowtie Analysis

To define and evaluate SCE's Physical Security risk, SCE has constructed a risk bowtie, as shown in Figure II-1. Each component of the bowtie represents a critical data point in evaluating this risk. SCE explains these components in detail in the sections that follow.

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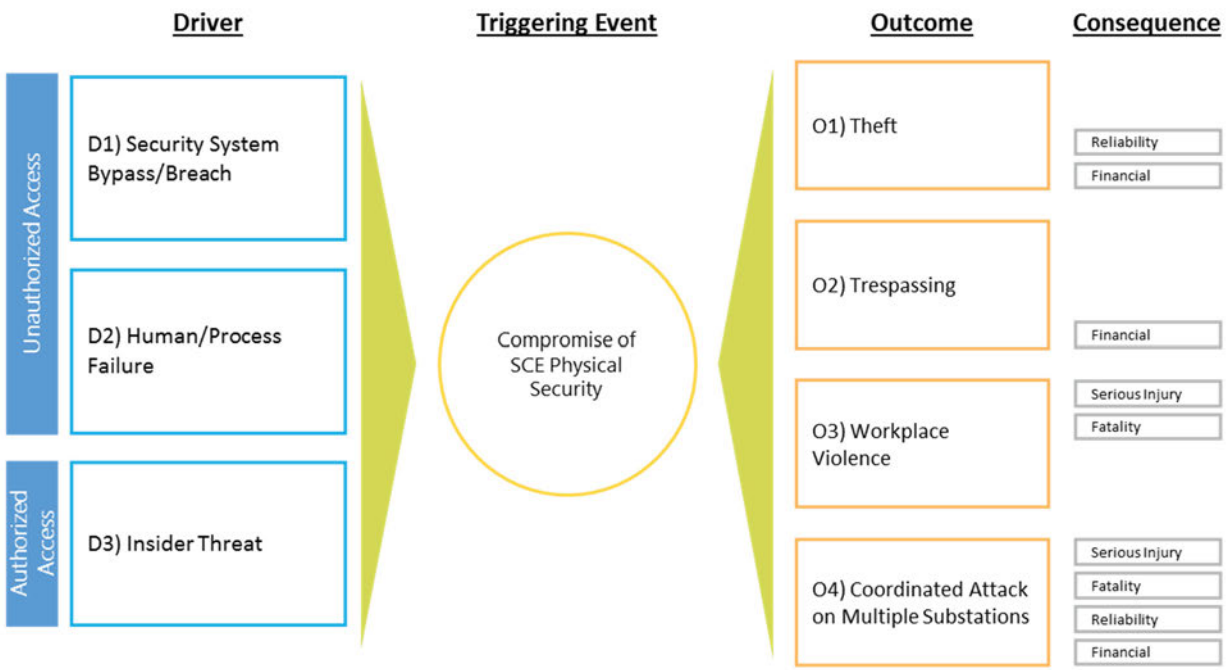
[14] 2017 CPUC Annual Report, Appendix E: 2017 Electrical Safety Incidents. Retrieved: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Annual_Reports/CPUC%20Annual%20Report%20-%20Draft%202-1-18%20-%20FINAL%20v3.pdf

[15] Michael Chertoff, "Building a Resilient Power Grid," *Electric Perspectives*, May/June 2014, p. 35.

[16] The threats that we face as a utility in one of the largest media markets and metropolitan centers in the world are significant, and those threats are continually evolving. To forecast the probability of successful breaches of our system's controls, we must make a series of educated assumptions based on what we know about our existing defenses, the demographics and capabilities of our attackers, and the growth and complexity of the physical security risk events we may face in the future.

Figure II-1 – Physical Security Risk Bowtie



D. Driver Analysis

SCE identified three drivers for this risk: D1 (Security System Bypass/Breach), D2 (Human/Process Failure), and D3 (Insider Threat). Figure II-2 shows the projected 2018 frequency count for each of these drivers.[17]

[17] Please refer to WP Ch. 9, pp. 9.1 – 9.3 *(Baseline Risk Assessment)* for further detail and evaluation of these drivers.

Figure II-2 – 2018 Projected Driver Frequency

Name	Freq	Frequency
D1 - Security System Bypass/Breach	92	
D2 - Human/Process Failure	59	
D3 - Insider Threat	1	

1. D1 – Security System Bypass/Breach

Security System Bypass/Breach is defined as an unauthorized intrusion into a secured location, accomplished by evading the security system or breaching the security perimeter. Some potential examples of Security System Bypass/Breach include:

- Intruder(s) cutting the perimeter fencing, barbed wire, and/or locks to gain entry into SCE substations, laydown yards, and facilities.
- Intruder(s) trespassing onto SCE substations, laydown yards, and facilities by climbing over or crawling under perimeter fencing.

Potential motives for Security System Bypass/Breach generally include:

- Stealing SCE or personal property (e.g. copper, tools, and/or equipment).
- Establishing a homeless encampment.
- Intending to commit acts of sabotage or work place violence.

SCE estimates an annual frequency of 92 incidents related to Security System Bypass/Breach. This estimate was derived by analyzing actual incidents from SCE's internal incident database for 2016-2017, and other external data, such as Federal Bureau of Investigation (FBI) active shooter incident data.[18]

[18] United States FBI File Repository: Active Shooter Incidents 2000-2017. https://www.fbi.gov/file-repository/active-shooter-incidents-2000-2017.pdf. Fortunately, high-impact events such as sabotage and workplace violence are rare events. In order to help predict the probability of occurrence for these events, SCE used FBI data in combination with internal data to create a larger sample size of data to model. Please note that external data was scaled down to SCE population; this allows SCE to develop a distribution based on a higher number of data points.

2. D2 – Human/Process Failure

This driver considers the failure of an SCE worker to follow policies, procedures, or protocols, or the absence of adequate processes in place that address physical security vulnerabilities. Some examples of Human/Process Failure include:

- SCE workers leaving company-issued and/or personal electronic equipment (e.g., laptops and cell phones) unattended and unlocked, resulting in the item being stolen.
- Lack of appropriate countermeasures to prevent person(s) from trespassing in and around substations, service centers, and other facilities, resulting in potential acts of sabotage or workplace violence.
- SCE workers (including security personnel) violating Company policy, leading to unauthorized access into a secure facility (e.g., tailgating[19] and unauthorized visitors).

SCE forecasts approximately 59 Human/Process Failure incidents in 2018. This estimate was based on SCE internal incident data and the FBI's active shooter data, scaled to SCE's service area.

3. D3 – Insider Threat

Insider Threat arises when an SCE worker uses current or previous access to facilities or insider knowledge with malicious intent. Consequently, an actual breach of security may not need to occur to commit the intended crime; the SCE worker may already have access. This driver occurs when there is an overt act that results in a physical security outcome.[20] Some examples of potential incidents that would be considered Insider Threat attacks include:

- A recently terminated employee using status and relationships to access SCE facilities and do physical harm to those inside the facility.

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[19] Tailgating: Following, or allowing someone to follow, into a Physical Security Perimeter (PSP) without appropriate authorization. NERC CIP requires that personnel without authorization into a PSP must be logged in/out and escorted.

[20] Incidents we captured that had no quantifiable outcome were reviewed and subsequently deemed to not be physical security threats within the definition used for RAMP. Accordingly, while these incidents remain as security concerns addressed within our physical security programs, they were excluded from the analysis.

- An employee using access to critical infrastructure to cause reliability incidents or widespread blackouts.
- An employee using their access to physically remove intellectual property or personally-identifying information from SCE facilities.

SCE forecasts approximately one insider threat incident per year. This estimate is based on SCE internal incident data from 2016 - 2017, a 2011 Irwindale workplace violence incident, FBI active shooter data from 2014 – 2017,[21] and publicly available external workplace violence incidents.

4. Driver Frequency Growth

A review of historical SCE data suggests a continued growth in the frequency of the triggering event. Additionally, other factors, such as the nationwide increase in attacks on utilities,[22] the success of attacks on the electrical infrastructure in other countries,[23] the availability of online documentation to support an attack, and the impact that an attack may have on a major media market like Southern California, are all indicators of an increased growth in physical security threats. SCE used internal data from 2013-2017 to determine growth rate.

SCE applied an annualized growth rate (7%) to each driver to illustrate the upward trend of physical security incidents in the utility industry.[24] In addition, SCE forecast growth in driver frequencies absent ongoing maintenance and implementation of current controls. For example, the baseline risk for this chapter contemplates removing fixed security officers at our

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[21] FBI data was scaled down from national scope to the size of the SCE workforce. The scaling factor was determined by dividing the SCE workforce population by the U.S. workforce population of approximately 155 million. (Source: https://data.bls.gov/timeseries/LNS12000000)

[22] Attacks in the United States from 2011-2017 were analyzed by SCE security personnel. This analysis identified a growing trend in attacks over time.

[23] Parfomak, Paul W. (2014, June 17.) "Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations." *Congressional Research Service.* Retrieved from https://fas.org/sgp/crs/homesec/R43604.pdf. This is a Congressional Research paper outlining the risk to HV transformers impacting the power grid, availability of information to execute such an attack, and potential impact.

[24] Please refer to WP Ch. 9, pp. 9.1 – 9.3 *(Baseline Risk Assessment).* This workpaper contains specific details on annualized growth rate calculation.

facilities, not maintaining fences, cameras and alarms any further, and performing no further maintenance on access controls.[25] The aggregate effect of this growth is shown in Table II-1.

Table II-1 – Driver Frequency Growth

Full Name	2018	2019	2020	2021	2022	2023	**Total**
Physical Security							
Baseline	**151.32**	**191.24**	**220.42**	**252.27**	**286.86**	**324.27**	**1,426.38**
Driver							
D1 - Security System Bypass/Breach	92.14	115.08	131.96	150.32	170.20	191.65	**851.34**
D2 - Human/ Process Failure	58.50	75.35	87.55	100.93	115.52	131.35	**569.19**
D3 - Insider Threat	0.68	0.81	0.92	1.03	1.14	1.27	**5.85**
Total	**151.32**	**191.24**	**220.42**	**252.27**	**286.86**	**324.27**	**1,426.38**

E. Triggering Event

The triggering event for this risk bowtie is a "compromise of SCE physical security." This event occurs when the physical security perimeter is compromised by unauthorized access, or when an insider compromises SCE's physical security, resulting in an adverse outcome.

F. Outcomes

SCE identified and evaluated the following outcomes that can occur when SCE physical security has been compromised: (1) Theft, (2) Trespassing, (3) Workplace Violence, and (4) Multiple Substation Attack. The likelihood of each outcome occurring, as shown in Figure II-3, was developed by reviewing internal data (i.e., SCE's investigation database), external data (i.e., FBI data, OSHA reports), and input from experts in physical security.

[25] In order to assess the baseline risk, we assume for the sake of example that all fixed security officers are removed from our facilities, with the exception of those officers directly associated with compliance.

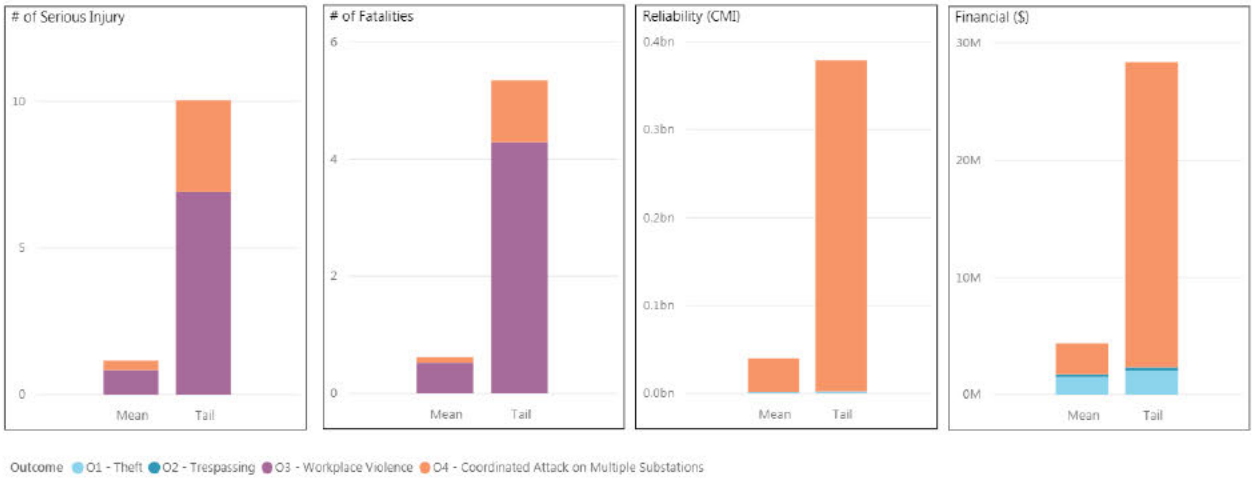
Figure II-3 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Theft	53.0 %	
O2 - Trespassing	46.9 %	
O3 - Workplace Violence	0.1 %	
O4 - Coordinated Attack on Multiple Substations	0.0 %	

Figure II-4 illustrates the composition of the modeled baseline risk in terms of each consequence dimension. This figure shows that the predominant safety impacts result from Outcome 3 (Workplace Violence), with additional safety impacts resulting from Outcome 4 (Coordinated Substation Attack).

Additionally, Outcome 4 results in the largest reliability and financial impacts of all the outcomes. The sections that follow detail the inputs used to derive these results.

Figure II-4 – Estimated Potential Consequences by Outcome



1. O1 – Theft

In this outcome, an individual steals SCE and/or personal property. Some of the most common theft incidents involve metal (copper), tools, and equipment. The most common way that intruders enter a facility is by cutting perimeter fencing or climbing over exterior fencing or walls. A real-life example took place on April 12, 2017 when two intruders cut perimeter

fencing to an SCE substation and removed 15 spools of copper wire valued at $45,000.[26] SCE has experienced an increase in theft incidents from 59 in 2016 to 101 in 2017. This represents a year-over-year increase of 71%.

Metal theft incidents represent 42% of all theft incidents reported in 2017. From 2016 to 2017, SCE experienced a 115% increase in metal theft incidents (i.e., 20 to 43 respectively).

Potential consequences from O1 (Theft) are summarized on an annualized basis in Table II-2. Reliability impacts are associated with service interruptions caused by theft. Financial costs are associated with property loss due to theft. For O1, the estimate of annual impacts is 2 million customer minutes of interruption (CMI) and $1.5 million of financial harm on a mean basis; and 2.5 million CMI and $2.1 million of financial harm on a tail-average basis.

Table II-2 – Outcome 1 (Theft): Consequence Details

Outcome 1		**Consequences**			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*			Outage impacts associated with theft, SCE internal database years 2016-2017.	Financial impacts associated with theft, SCE internal data from 2016-2017.
Model Outputs *(Annual Average)*	NU - Mean			2.0M CMI	$1.5M
	NU - Tail Avg			2.5M CMI	$2.1M

2. O2 – Trespassing

Trespassing occurs when an unauthorized person(s) enters onto SCE facilities without permission. This outcome does not include incidents where the trespasser's intent was to incite one of the other outcomes (theft, workplace violence, or sabotage).

Potential consequences from trespassing are summarized on an annualized basis in Table II-3. Financial costs are associated with damage due to trespassing. For trespassing, the estimate of annual impacts is $244,000 of financial harm on a mean basis; and $306,000 of financial harm on a tail-average basis.

[26] NAVEX Case No. 2017-4-15500. NAVEX is a widely-used software tool that SCE also employs to track and manage investigative efforts and cases.

Table II-3 – Outcome 2 (Trespassing): Consequence Details

Outcome 2		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*				Financial impacts associated with trespassing, SCE internal data from 2016-2017.
Model Outputs *(Annual Average)*	NU - Mean				$244K
	NU - Tail Avg				$306K

3. O3 – Workplace Violence

The scope for the workplace violence outcome includes incidents that could result in a serious injury and/or fatality. The U.S. Department of Labor's Occupational Safety and Health Administration (OSHA) defines workplace violence as any act or threat of physical violence, harassment, intimidation, or other threatening disruptive behavior that occurs at the work site. For purposes of this RAMP analysis, we only captured the threat of cases that resulted in serious injury or fatality.[27]

Potential consequences from workplace violence are summarized on an annualized basis in Table II-4. Serious Injury and Fatality impacts are associated with active shooter incidents. For this outcome, the estimate of annual impacts is 0.84 injuries and 0.52 fatalities on a mean basis; and 6.92 injuries and 4.29 fatalities on a tail-average basis.

[27] https://www.osha.gov/SLTC/workplaceviolence/ This is a Department of Labor summary of workplace violence statistics.

Table II-4 – Outcome 3 (Workplace Violence): Consequence Details

Outcome 3		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	Serious injury associated with active shooter, based on 2011 internal data and 2014-2017 FBI data.	Fatality associated with active shooter, based on 2011 internal data and 2014-2017 FBI data.		
Model Outputs (*Annual Average)*	NU - Mean	0.84	0.52		
	NU - Tail Avg	6.92	4.29		

4. O4 – Coordinated Attack on Multiple Substations

This outcome results in a coordinated attack on multiple substations. This could impact the bulk electric system on a widespread basis, with consequences including serious injuries, fatalities, reliability, and financial. According to the Congressional Research Service,[28] a coordinated and simultaneous attack on substations would be catastrophic, with severe implications over a large geographic area and extended blackouts.[29] Fortunately, such an attack has not occurred in the United States to date. However, an attack is possible in SCE's service territory, given:

- The increased frequency of sabotage attempts in the United States between 2011 and 2017 (e.g., the 2013 Metcalf Substation attack, the 2013 500kV substation attack in Lonoke County, and others);
- The increasing availability of online documentation and information that can aid in planning and supporting an attack;[30]

[28] The Congressional Research Service (CRS) works exclusively for the United States Congress, developing policy and legal analysis to members of the House and Senate, regardless of party affiliation

[29] Parfomak, Paul. "Physical Security of the U.S. Power Grid: High Voltage Transformer Substations." June 17, 2014. Page 6 https://fas.org/sgp/crs/homesec/R43604.pdf This article discusses the implications of an attack on HV transformers and potential catastrophic impacts to the economy and health/welfare of society.

[30] National Academies Press. (2012) Terrorism and the Electric Power Delivery System, "Physical Security Considerations for the Electric Power Systems", Chapter 3, p. 32. Retrieved from https://www.nap.edu/read/12050/chapter/5

- Los Angeles, as a service area, comprises a high density of customers to geographic areas, headquarters a great deal of the media/entertainment industry, and has a very high profile in the news. Thus, an attack in Los Angeles will be a much more reported-upon event and will provide the attackers with relatively higher visibility.

Accordingly, SCE (with support from our SMEs)[31] developed a scenario that is analogous to the scenarios in NERC's 2015 Grid Security Exercise – GridEx III.[32]

The result of this type of coordinated attack on multiple substations would be the loss of critical grid components, unauthorized access to substations, and serious injuries and/or deaths to employees or members of the public.[33]

Potential consequences from this outcome, coordinated attack on multiple substations, are summarized on an annualized basis in Table II-5. Serious Injury, Fatality, Reliability and Financial impacts are associated with this outcome. The estimate of annual impacts includes approximately 0.32 serious injuries, 0.10 fatalities, 37.67 million CMI, and $2.61 million on a mean basis; and 3.13 serious injuries, 1.05 fatalities, 376.11 million CMI, and $26.03 million a tail-average basis.

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[31] Please refer to WP Ch. 9, pp. 9.4 – 9.5 *(Subject Matter Expert Qualifications)*. This workpaper discusses the background and experience of Subject Matter Experts.

[32] (March, 2016.) "Grid Security Exercise GridEx III Report." *North American Reliability Corporation.* Retrieved from https://www.nerc.com/pa/CI/CIPOutreach/GridEX/NERC%20GridEx%20III%20Report.pdf. This is the GridEx III exercise documentation for a multi-substation attack.

[33] As mentioned earlier in this report, we may be unable to share information beyond a certain level of detail, so that we continue to protect sensitive physical security information and protocols.

Table II-5 – Outcome 4 (Coordinated Attack on Multiple Substations): Consequence Details

Outcome 4		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE evaluated a potential physical attack scenario where an adversary obtains control of our grid assets and causes physical damage to, or destruction of, the electrical system. This scenario is a hypothetical scenario of a coordinated attack on multiple substations.			
Model Outputs	NU - Mean	0.32	0.10	37.67M CMI	$2.61M
	NU - Tail Avg	3.13	1.05	376.11M CMI	$26.03M

III. Compliance & Controls

SCE has controls in place to minimize the physical security risk that exists across SCE's facilities. These controls are scoped to protect facility classes within SCE's facility portfolio, including: electric facilities (substations), generation facilities, and non-electric facilities (office buildings, warehouses, service centers, etc.).[34] Because not every facility addressed in these controls will have the same risk exposure, the actual set of physical security measures at each facility may vary. Hence, similar to how we present physical security programs in our GRC, we present our controls on a program basis. SCE has been operating these compliance activities and controls as critical components of our layered defense protection approach for many years.[35]

Table III-1 below maps existing controls to drivers, outcomes, and consequences, in addition to showing 2017 recorded costs for both compliance activities and controls.

Table III-1 – Inventory of Compliance & Controls[36]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	NERC CIP-014	Not Modeled	Not Modeled	Not Modeled	$ 26.54	$ -
CM2	NERC V6 Low BES Sites	Not Modeled	Not Modeled	Not Modeled	$ 3.38	$ -
C1a	Grid Infrastructure Protection - Base	All	All	All	$ 11.62	$ -
C1b	Grid Infrastructure Protection - Enhanced	All	All	All		
C2	Protection of Generation Capabilities	All	All	All		
C3a	Non-Electric Facilities/Protection of Major Business Functions - Base	All	All	All	$ 10.15	$ -
C3b	Non-electric Facilities/Protection of Major Business Functions - Enhanced	All	All	All		
C4	Asset Protection	All	All	All	$ -	$ 25.75

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

[34] Please refer to WP Ch. 9, pp. 9.6 – 9.20 *(Control & Mitigation Risk Reduction Effectiveness Workpaper)*

[35] Please refer to WP Ch. 9, pp. 9.21 – 9.26 *(Control or Mitigation Effectiveness Workpaper)*

[36] Recorded costs for C1 and C2 are provided in aggregate. Prior to 2018, the electric grid and generation protection programs were addressed in one program (the Electric Facilities Blanket in the 2018 GRC).

A. CM1 – NERC CIP-014

NERC CIP-014[37] was established in 2014 by NERC and approved by the Federal Energy Regulatory Commission (FERC) as a standard to protect transmission substations, and their associated primary control centers, against physical attack. NERC CIP-014 has been effective since January 26, 2015 and is a threat and vulnerability analysis to uncover potential threats, weaknesses, and corresponding risks. Under the standard, utilities must perform an initial risk assessment. This assessment must then be reviewed by an independent third party. Utilities subsequently perform a more tailored assessment and evaluation of potential threats and the associated vulnerabilities related to each identified critical location.

Finally, the utility must develop and implement a plan to protect those identified assets from physical threats, and have that plan verified by an independent third party.[38] The costs shown for CM1 represent the costs related to implementing the physical security plan under CIP-014 for that given year.

B. CM2 – NERC CIP-003-v6

On January 21, 2016, in order No. 822, FERC approved NERC CIP-003-v6[39] to establish physical security controls to protect the Low Impact BES Cyber System. These controls require policies for each Responsible Entity (e.g. SCE) to restrict physical access to our BES facilities based on need as determined by the Responsible Entity.

C. C1 – Grid Infrastructure Protection

Grid Infrastructure Protection[40] is an existing program that helps secure SCE's electric facilities against physical threats. These facilities primarily consist of substations and their

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[37] https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-2.pdf. This document defines NERC CIP requirements.

[38] http://www.electricenergyonline.com/energy/magazine/813/article/Utility-Security-Understanding-NERC-CIP-014-Requirements-and-Their-Impact.htm. History of physical protection of power grid and specific NERC-CIP requirements.

[39] https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-003-6.pdf. This is a write up of the specific CIP-003-6 — Cyber Security — Security Management Controls.

[40] This control was presented in SCE's 2018 GRC as part of the "Electric Facilities Blanket." See A.16-09-001, SCE's Test Year 2018 GRC, Exhibit SCE-07, Vol. 5, p. 43.

respective control centers. This control is deployed based on the criticality of need and the potential impact of a breach. Criticality is defined by assessing the amount of load served, the number of network connection points, and other factors for each substation. These factors are then used to tranche the substations into tiers: Tier 1 accounts for the most critical electrical facilities; Tier 4 is the least critical.

Through this control, SCE deploys various physical security measures that combine to actively deter, detect, delay, and deny threats using a layered defense approach. These measures can include a suitable combination of access control, alarms, perimeter protection (e.g., fencing, walls, barbed wire, etc.), video surveillance, and other measures. SCE continuously assesses the threat landscape and modifies the security measures for each substation accordingly. For example, when a facility has been identified as being a prime target of copper thieves, we arrange to install enhanced fencing to deter thieves from cutting or climbing the fencing.

SCE contemplated two options for deploying this control over the 2018-2023 RAMP period:

1. Control Options

a. C1a – Base Option

The Base option (C1a) will continue the deployment, scope, and features of the existing controls in place at electrical facilities. These activities include, but are not limited to, the following:

- Upgrading fencing;
- Improving lighting;
- Updating the processes to identify facilities requiring improved monitoring by a combination of security cameras and other technology;
- Detecting criminal activity that results in deploying uniformed security officers; and,
- Improving access management and control processes.

b. C1b – Enhanced Option

The Enhanced option (C1b) includes all measures identified in the Base option (C1a), but also includes improvements in managing and controlling access. These enhancements include tamper-resistant gate motors and hardware, and perimeter video analytics. The enhancements also encompass enhanced visitor/access management technology

that replaces rudimentary paper logs with an automated system that efficiently logs, tracks, and manages visitors.

2. Drivers Impacted

Both options for this control (C1a and C1b) will impact all drivers. For example, physical barriers such as walls and gates, as well as video surveillance and/or improved lighting, can reduce the frequency of D1 (System Security Breach/Bypass). Updating security processes and access management systems can reduce the frequency of D2 (Human/Process Failure). Access restrictions for employees can reduce the frequency of D3 (Insider Threat) by granting access to only those areas where the employee specifically needs access to accomplish job duties.

3. Outcomes and Consequences Impacted

Both options for this control (C1a and C1b) will impact all outcomes. For example, the early detection and mitigation of suspicious and criminal activity in and around facilities is improved with security cameras and other technology (e.g., gunshot detection). This aids in rapidly deploying security officers and law enforcement, thereby reducing the consequences associated with all outcomes. Both control options allow SCE to respond to incidents more rapidly and effectively. Furthermore, this control helps conceal the most critical assets within substations to reduce injury, theft, or damage (to the assets or associated assets).

D. C2 – Protection of Generation Capabilities

Protection of Generation Capabilities[41] is an existing control that aims to protect SCE's generation facilities against physical threats. This control implements most of the security measures used in the Grid Infrastructure Protection control; such as access control, alarms, perimeter protection such as block wall and steel gates, and video surveillance. However, C2 tailors these measures to fit the specific generation assets' environment and landscape.[42] For example, our hydro facilities are often located in rural or remote areas, and the hydro

[41] This control was presented in SCE's 2018 GRC as the part of the "Electric Facilities Blanket." See A.16-09-001, Exhibit SCE-07, Vol. 5, p. 43. Moving forward, it will be presented as a separate control.

[42] SCE's Generation Portfolio includes 78 facilities.

complex[43] may cover a vast amount of territory. This control can also include enhanced security measures to meet the specific and unique needs of the generation facility being protected.

1. Drivers Impacted

The physical security measures used in this control will impact all drivers. For example, this control will reduce the frequency of D1 (System Security Breach/Bypass) by making it more difficult to penetrate our security perimeter. For instance, barbed wire fencing could deter individuals from entering a hydro facility. In addition, this control reduces the frequency of D2 (Human/Process Failure) by implementing access control, which will prevent and reduce the frequency of unauthorized access. Similarly, access control also reduces the frequency of D3 (Insider Threat) by restricting access to only those employees who should have it.

2. Outcomes and Consequences Impacted

As this control deploys similar measures as C1 (Grid Infrastructure Protection), it similarly affects each outcome and consequence. The physical security measures in C2 are tailored to the needs of each generation facility, and reduce the magnitude of impact associated with each outcome by deploying early detection technologies and faster response techniques.

E. C3 – Non-Electric Facilities - Protection of Major Business Functions

This control protects SCE's non-electric facilities against physical threats.[44] Non-electric SCE facilities include the corporate general offices, service centers, business offices, call centers, data centers, and warehouses. Security fencing and gates similar to what is used in C1 (Grid Infrastructure Protection) and C2 (Protection of Generation Capabilities) may be used to protect service centers, data centers, and warehouses in industrial environments. A combination of uniformed security staff, access controls, video surveillance, and security alarms are typically used to protect corporate general offices and business offices located in urban

[43] Hydro complexes can include tunnels, penstocks, reservoirs, etc.

[44] This control was presented in SCE's 2018 GRC as the "Non-Electric Facilities Blanket." See A.16-09-001, SCE-07, Vol. 5. p. 37.

environments. The mix of security measures deployed to each location is uniquely tailored to the functions, criticality, and security risks of each facility.

1. Control Options

a. C3a – Base Option

The Base option (C3a) is an ongoing effort to protect SCE's assets at non-electric facilities in response to rising incidents of theft, trespassing, and workplace violence. Security control measures within this base option include, but are not limited to, a maintenance program,[45] a refresh program,[46] and associated process and procedures to improve how we identify and respond to threats. This control combines physical security technologies such as access controls based on corporate identification badges, video surveillance, and security alarms.

c. C3b – Enhanced Option

The Enhanced option (C3b) includes measures identified in the Base option (C3a). But it also includes improvements to how we manage and control access, so that we can further mitigate risks to assets and personnel at non-electric facilities. A new technology for managing and controlling access would replace rudimentary paper logs with an automated system that tracks visitors and enhances access management. This would increase control and accountability in managing access for our non-electric facilities. Deploying these enhancements would first target facilities that have the highest identified risks and criticality to our service obligations.

2. Drivers Impacted

Both options for this control (C3a and C3b) will impact all drivers. For example, access control affected through uniformed security officers can reduce the frequency of D1 (Security System Bypass/Breach). Updating security processes and access management systems can reduce the frequency of D2 (Human/Process Failure). Access restrictions for employees can

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[45] The maintenance program establishes a preventive maintenance schedule for continuity of security equipment capabilities.

[46] The refresh program establishes a prudent schedule to replace security equipment.

reduce the frequency of D3 (Insider Threat) by only granting employees access to authorized and as-needed areas.

3. Outcomes and Consequences Impacted

Both options for this control (C3a and C3b) will impact all outcomes. For example, uniformed security patrols are likely to deter individuals from stealing company assets, thereby we assumed reduction in the financial consequences associated with O1 (Theft). Access control (such as using badge readers) reduces the number of unauthorized accesses; this reduction in turn reduces the number of O2 events (Trespassing). Early detection of suspicious and criminal activity in and around non-electrical facilities is improved with video surveillance and duress alarms. This aids in rapidly deploying security officers and law enforcement, thereby reducing the consequences associated with O3 (Workplace Violence) and O4 (Coordinated Attack on Multiple Substations).

F. C4 – Asset Protection - O&M

Asset Protection is an existing control that helps protect SCE workers against physical threats.

With this control, SCE is able to: 1) properly vet SCE workers before hiring via a background investigation; 2) investigate security incidents and concerns; 3) train employees on preventing workplace violence and responding safely and appropriately to active shooter incidents; 4) deploy the Threat Management Team (TMT) to assess threats to SCE workers; and, 5) employ security officers to protect facilities and respond to security threats and incidents.

1. Drivers Impacted

The physical security measures in this control are designed to impact all drivers. The frequency of drivers D1 (Security System Bypass/Breach) and D2 (Human/Process Failure) are reduced by deploying security officers to deter violence and property crimes, observe and report security incidents, control access to facilities, and provide immediate response capability. The Insider Threat program reduces the frequency of D3 (Insider Threat) by identifying potential threats before they materialize.

2. Outcomes and Consequences Impacted

The physical security measures implemented in this control will impact all outcomes and their associated consequences. By implementing the principal components of the program

as outlined above SCE can respond to risks and incidents more rapidly and effectively. Safety, reliability, and financial consequences will be reduced when each outcome occurs.

IV. Mitigations

Beyond the compliance and control activities described in Section III, SCE monitors and evaluates more effective ways to respond to and mitigate evolving security threats. These efforts are summarized in Table IV-1.

Table IV-1 – Inventory of Mitigations

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Proposed	Alt. #1	Alt. #2
M1a	Insider Threat Program Enhancement & Information Analysis - Base	All	All	All	X		X
M1b	Insider Threat Program Enhancement & Information Analysis - Enhanced	All	All	All		X	
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	All	All	All	X	X	
M3	Smart Key Program Phase 2 - Electrical Sites	All	All	All		X	
M4	Smart Key Program Phase 3 - Remaining Non Electric Sites	All	All	All		X	

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report.

A. M1 – Insider Threat Program Enhancement & Information Analysis

This mitigation will improve SCE's ability to identify and respond to insider threats by implementing new processes to collect and analyze data. This program will be implemented from 2019-2023, and include the following primary components: 1) Expand the background investigation process described in C4 (Asset Protection) to include a process for evaluating SCE applicants' and contractors' online presences, including social media, as part of the selection process; and 2) Create a new internal threat intelligence, data, and analytics program to proactively mitigate insider threat against SCE workers, the Company, and/or assets.

This mitigation will include qualitatively and quantitatively analyzing potential threat events. Once identified, threats will be assessed and safeguarded against. To continuously improve, we will refine our insider threat security processes, deploy appropriate resources, and enact adequate protections to minimize any future unexpected threats.

1. Mitigation Options

SCE contemplated two options for implementing this mitigation: a Base option M1a (Insider Threat Program), and an Enhanced option M1b (Insider Threat Program).

a. M1a – Base Option

This mitigation implements a comprehensive, enterprise-wide program to protect against insider threats that could lead to: workplace violence, intellectual property theft, compromise of grid control, exposure of critical electrical infrastructure information, and physical-cyber joint vulnerabilities.

The mitigation includes the development of a new training program for all employees, risk identification and analysis, enterprise data analytics, and joint physical-cyber security measures. This program will centralize various insider threat reduction efforts from across the company to standardize efforts, reduce gaps, and improve effectiveness.

Implementing a comprehensive enterprise Insider Threat program allows us to enhance identity management, and fosters improvement in:

- Evaluating employee risk probability;
- Identifying high-risk employees;
- Developing Insider Threat metrics;
- Proactively identifying insider threats using internal resources; and,
- Strengthening employee awareness of security protocols through training and internal communications.

b. M1b – Enhanced Option

This mitigation option implements an enhanced and accelerated version of the Insider Threat program presented above (M1a). This mitigation option will primarily utilize external experts to analyze unusual behaviors or patterns that may present risks. This should allow us to reduce risks and vulnerabilities faster and more comprehensively than what our current capabilities and processes can do. Moreover, using external resources can be expanded or reduced as needed to implement this mitigation option faster than the base option.

2. Drivers Impacted

The physical security measures used for M1a and M1b will impact D3 (Insider Threat) by preventing high-risk individuals from joining the SCE workforce, and identifying and addressing existing high-risk workers before they can commit malicious acts against SCE. In addition, M1a and M1b (Insider Threat Program – Base & Enhanced) will impact drivers D1 (Security System Bypass/Breach) and D2 (Human/Process Failure) by conducting awareness training that will help employees reduce the frequency of incidents by:

- Being alert to detect suspicious behavior from internal or external actors;
- Adopting best practices for maintaining security protections; and
- Having ongoing awareness training so that physical security procedures are reinforced on an annual basis.

3. Outcomes and Consequences Impacted

M1a and M1b will impact all outcomes. O1 (Theft) is reduced when unusual behavior patterns from internal actors are identified, investigated and ended. Financial and reliability consequences associated with O2 (Trespassing) and O4 (Coordinated Attack on Multiple Substations) events are reduced when employees are trained to detect and report suspicious behavior from potential intruders. O3 (Workplace violence) is reduced as SCE hires lower-risk workers.

B. M2, M3, M4 – Smart Key Program: Phases 1, 2, and 3

Mitigations M2, M3, and M4 implement Smart Key technology to different facilities. Smart Key technology replaces conventional locks and keys, such as those found at electric facilities, generation facilities, office buildings, etc. Smart Keys include both mechanical and electronic features, and integrate with SCE's access control system. Smart Keys[47] allow different access authorizations to be assigned to specific individuals. They are configured to have a set expiration period. This reduces the possibility of, and consequences of, unauthorized use when a key is lost or stolen.

The benefits of Smart Keys also include greater effectiveness in controlling access with a time-and-date stamped record of every use, reduced perimeter security vulnerabilities, reduced consequences of lost or stolen keys, and greater employee accountability in managing keys.

SCE considered implementing Smart Keys through three phases over the RAMP period:

- Phase 1 (M2): Approximately 130 of SCE's most critical facilities.[48]

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[47] Smart Key locks are wire-free. However, door hardware mechanisms must be compatible to be able to function. Similarly, Smart Key activation devices require IT infrastructure such as LAN connectivity and POE.

[48] Facility criticality is determined by internal business impact analyses that consider regulatory requirements, critical business functions, and impact to the bulk electric system.

- Phase 2 (M3): Approximately 800 of the remaining SCE electrical facilities are captured by this phase.
- Phase 3 (M4): Approximately 300 of SCE's non-electric facilities.

1. Drivers Impacted

The Smart Key Program (M2, M3, and M4) will impact D1 (Security System Bypass/Breach) and D2 (Human/Process Failure) by helping prevent unauthorized access and providing greater accountability for the use of keys.

In addition, Smart Keys reduce the frequency of D3 (Insider Threat) events by limiting access permissions to only those individuals who have a justified business need. Smart keys can also detect unauthorized access attempts; such detection can alert SCE to concerning behavior that is subject to investigation and disciplinary action.

2. Outcomes and Consequences Impacted

M2, M3, and M4 will impact all outcomes and associated consequences. For example, traditional keys turn into unrestrained keys once they are reported as lost or stolen. However, Smart Keys allow us to track and control keys efficiently and effectively by disabling them or promptly removing associated access permissions.

Smart Key technology reduces potential O1 (Theft) events. It prevents and reduces O2 (Trespassing) events because access permissions are only assigned to authorized users that have a legitimate work reason for possessing access. The use of Smart Key technology reduces events related to O3 (Workplace Violence) and O4 (Coordinated Attack at Multiple Substations). This technology helps identify unusual behavior patterns in use of the Smart Key, so that SCE can investigate and end threats.

V. Proposed Plan

SCE has evaluated the risk controls and mitigations discussed in Sections III and IV, and we have developed a Proposed Plan. The controls and mitigations included in this plan are shown in Table V-1 – Proposed Plan below.

The Proposed Plan best positions SCE to address both the low-probability, high-impact physical attack risks, and the more frequent, lower-impact physical security risk events.

Table V-1 – Proposed Plan (2018-2023 Totals)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1b	Grid Infrastructure Protection - Enhanced	2018	2023	$ 144.66	$ 0.79	2.10	0.014	8.25	0.057
C2	Protection of Generation Capabilities	2018	2023	$ 22.63	$ 0.70	1.66	0.071	6.53	0.280
C3b	Non-electric Facilities/Protection of Major Business Functions - Enhanced	2018	2023	$ 74.02	$ 0.94	2.14	0.029	8.39	0.112
C4	Asset Protection	2018	2023	$ 9.90	$ 123.22	1.88	0.014	7.39	0.056
M1a	Insider Threat Program Enhancement & Information Analysis - Base	2019	2023	$ -	$ 1.47	1.17	0.795	4.75	3.227
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	2019	2022	$ 9.04	$ 0.23	1.65	0.178	6.55	0.707
			Total - Proposed Plan	**$ 260.24**	**$ 127.35**	**10.60**	**0.027**	**41.86**	**0.108**

MARS = Multi-Attribute Risk Score
MRR = Mitigated Risk Reduction
RSE = Risk Spend Efficiency

A. Overview

As discussed in Section III, SCE has designed location-specific and enterprise-wide physical security controls, and is in the process of implementing these controls at our facilities in a manner that prudently addresses current risk exposure and safeguards critical facilities. These security standards and controls were developed based on: 1) examining best practices, 2) analyzing incident and industry trends, 3) obtaining input from SMEs across the company, and 4) using security risk assessments that SCE and qualified vendors performed on Company facilities. These standards, controls, and associated procedures, are deployed as part of a layered strategy to detect, deter, delay, disrupt, and respond to the threats that exist today while taking into account constraints in authorized spending.

However, SCE faces escalating threats of theft, sabotage, and workplace violence risks in the future. As such, in the Proposed Plan, SCE strengthens and expands existing physical security practices by implementing Grid Infrastructure Protection – Enhanced (C1b), Protection of Generation Capabilities (C2), Non-Electrical Facilities/Protection of Major Business Function– Enhanced (C3b), and Asset Protection (C4). In addition, SCE supplements this work with enhanced capabilities, tools, and resources to, address the potentials for low-probability / high-impact physical attacks by implementing the Insider Threat Program – Base (M1a) and Phase 1 of the Smart Key Program (M2).

B. Execution Feasibility

SCE evaluated the feasibility of executing the Proposed Plan based on current organizational capabilities, security technology, and ongoing work. The controls chosen for the Proposed Plan either continue or enhance existing work, which SCE has been able to execute. As such, SCE believes that the Proposed Plan can feasibly be executed.

C. Affordability

The Proposed Plan costs less than Alternative Plan #1, but more than Alternative Plan #2. The Proposed Plan strikes a balance between reducing risk and increasing cost. SCE is accepting a certain level of risk by: (a) not pursuing Mitigation M1b (Insider Threat Program – Enhanced) to counteract an evolving insider threat risk, and (b) partially limiting the implementation of the Smart Key program. However, SCE believes that the Proposed Plan will adequately address the balance of physical security threats.

The Proposed Plan delivers the second highest RSE of the three mitigations plans. Alternative Plan #1 provides the highest RSE (on both a mean and tail-average basis), but costs significantly more than the Proposed Plan. SCE considered whether additional mitigation investment would yield commensurate risk reduction. We determined that the increased risk reduction came at a relatively higher cost, and that at this time the Proposed Plan as structured is the most effective and balanced plan to address this risk.

D. Other Considerations

Advances in the sophistication of physical attack threats and development of new attack methods may render current risk mitigation activities less effective. SCE will continue to proactively monitor the emergence of future threats. If we have not anticipated the evolving threat correctly, the mitigations laid out in the Proposed Plan may not be sufficient. In addition,

global politics and conflict can potentially lead to increased volume and sophistication of attacks on our electric system.

VI. Alternative Plan #1

SCE evaluated alternative options to address this physical security risk and developed an Alternative Plan #1 as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018-2023 Totals)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1b	Grid Infrastructure Protection - Enhanced	2018	2023	$ 144.66	$ 0.79	1.92	0.013	7.55	0.052
C2	Protection of Generation Capabilities	2018	2023	$ 22.63	$ 0.70	1.51	0.065	5.97	0.256
C3b	Non-electric Facilities/Protection of Major Business Functions - Enhanced	2018	2023	$ 74.02	$ 0.94	1.95	0.026	7.68	0.102
C4	Asset Protection	2018	2023	$ 9.90	$ 123.22	1.71	0.013	6.74	0.051
M1b	Insider Threat Program Enhancement & Information Analysis - Enhanced	2019	2023	$ 0.70	$ 1.49	1.42	0.649	5.72	2.614
M2	Smart Key Program Phase 1 - Listed BR/BIA Critical Sites and CS Tier Sites	2019	2022	$ 9.04	$ 0.23	1.50	0.162	5.97	0.645
M3	Smart Key Program Phase 2 - Electrical Sites	2019	2023	$ 30.97	$ 0.11	1.16	0.037	4.70	0.151
M4	Smart Key Program Phase 3 - Remaining Non Electric Sites	2022	2023	$ 8.43	$ 0.13	1.04	0.121	3.98	0.465
		Total - Alternative Plan #1		**$300.34**	**$127.60**	**12.21**	**0.029**	**48.31**	**0.113**

MARS = Multi-Attribute Risk Score
MRR = Mitigated Risk Reduction
RSE = Risk Spend Efficiency

A. Overview

Similar to the Proposed Plan, Alternative Plan #1 continues to deploy SCE's layered physical security approach. This plan then adds significant incremental resources to protect against Insider Threats and accelerates deploying Smart Keys and visitor access controls across the enterprise.

B. Execution feasibility

This plan would be more difficult than the Proposed Plan to implement due to the amount of resources required to rapidly deploy Smart Key technology to approximately 1,230 facilities over a shorter period of time. This deployment plan not only requires incremental resources to perform the Smart Key retrofits, but also a coordinated team of internal resources to integrate the new data and processes into our back-office systems, train personnel across all of these locations, and implement new processes and procedures for the use and disposition of Smart Keys.

Due to the aggressive scope and pace of this deployment, our ability to do a scaled field placement to test the technology and the business response to it would be limited. At this time, SCE believes that a more balanced approach for deploying this technology would allow benefits to be achieved at our more critical locations in short order, while permitting us to further evaluate this technology and deploy it to the balance of our locations over time.

C. Affordability

This plan presents the largest scope of work to increase our physical security protection. Not surprisingly it appears that it would reduce the most risk of the three mitigation plans. However, this is also the most expensive plan of the three.

Alternative Plan #1 has the highest RSE of the three plans. After further considering the various operational factors and cost implications of this plan, we determined that a more balanced approach to rolling out the new Smart Key technology would provide near-term benefits at a pace that would not unduly constrain the limited financial and human resources available.

D. Other Considerations

The same additional considerations raised in the Proposed Plan apply to Alternative Plan #1.

VII. Alternative Plan #2

SCE evaluated another alternative option to address this physical security risk, as shown in Table VII-1.

Table VII-1 – Alternative Plan 2 (2018-2023 Totals)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1a	Grid Infrastructure Protection - Base	2018	2023	$ 109.67	$ 0.60	1.62	0.015	6.34	0.057
C2	Protection of Generation Capabilities	2018	2023	$ 22.63	$ 0.70	1.84	0.079	7.24	0.310
C3a	Non-Electric Facilities/Protection of Major Business Functions - Base	2018	2023	$ 59.37	$ 0.60	1.56	0.026	6.08	0.101
C4	Asset Protection	2018	2023	$ 9.90	$ 123.22	2.08	0.016	8.22	0.062
M1a	Insider Threat Program Enhancement & Information Analysis - Base	2019	2023	$ -	$ 1.47	1.29	0.876	5.26	3.573
			Total - Alternative #2	**$201.57**	**$126.60**	**8.39**	**0.026**	**33.14**	**0.101**

A. Overview

Alternative Plan #2 continues to deploy SCE's layered physical security strategy, albeit at a less expansive level than the Proposed Plan. This plan maintains the pace of deploying existing controls by implementing Grid Infrastructure Protection – Base (C1a), Protection of Generation Capabilities (C2), Non-Electrical Facilities/Protection of Major Business Function – Base (C3a), and Asset Protection (C4). Alternative Plan #2 will address fewer facilities over the RAMP period, relative to the Proposed Plan. Alternative Plan #2 also adds modest incremental resources to protect against insider threat risk, Insider Threat Program – Base (M1a).

Contrary to the Proposed and Alternative Plan #1, this plan does not mitigate any risk associated with lost or stolen keys, nor the security perimeter vulnerabilities related to traditional locks and keys. Furthermore, Alternative Plan #2 does not prepare SCE for a low-probability, but high-impact attack as effectively as the Proposed Plan or the Alternate Plan #1. Alternative Plan #2 addresses risks at a slower pace compared to the Proposed Plan; this will potentially expose SCE to a larger number of outcomes and associated consequences.

B. Execution Feasibility

Alternative Plan #2 represents a reduced scope of work for three major control and mitigation programs (C1a, C3a, M1a) relative to the Proposed Plan. Accordingly, as SCE believes the Proposed Plan is fully executable, this plan should likewise be feasible to execute.

C. Affordability

This plan is the least-cost option. However, it provides the lowest RSE of the three mitigation plans.

D. Other Considerations

The same additional considerations raised in the Proposed Plan apply to Alternative Plan #2.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

This first RAMP report gave us valuable insight into how we track data to quantify the physical security risk bowtie. Existing systems to track incident data meet our current operational needs. However, SCE learned that the existing systems did not entirely support how SCE modeled the physical security risk in this RAMP report. As such, SCE will consider modifying or augmenting the tracking and reporting capabilities of current systems so that we can continue to improve and refine our evaluation of this RAMP risk. This may involve developing a more centralized, cross-functional incident management database. Such a database would allow future quantitative risk analyses to comprehensively view SCE's physical security landscape, tie risk drivers to risk outcomes, and examine the associated safety, reliability, and financial consequences. A comprehensive database will allow SCE to better use a probabilistic/predictive approach to identify potential threats and obtain a greater understanding of potential trends or areas that we must focus on.

In addition to the fundamental physical security measures employed by SCE (e.g., fencing, lighting, security officers, etc.), the RAMP risk analysis helped confirm that the Company should diligently consider new mitigation options as technology improves and evolves to best address this risk (e.g. facial recognition software, personal identification technology, systems to identify gunshots and their direction of travel, etc.).

B. Data Collection & Availability

Obtaining data to quantify the risk bowtie elements was time-consuming because of the way that we track incidents currently. Further, some elements of the bowtie have very limited historical data, and we had to rely on industry and government data (scaled to SCE's level of exposure).

Ideally, a standard security report management system could be created that gives SCE a comprehensive view of our physical security landscape and risk. This would allow us to more efficiently evaluate physical security risks, and let us more quickly quantify risk drivers, risk events, risk outcomes, and associated consequences.

Further, while low-probability, high-impact incidents (e.g., sabotage and workplace violence) are fortunately limited, these are some of the higher-priority physical security concerns. Historical data related to these events is limited. The limited data set presents a

challenge when populating inputs to probabilistic risk models, such as the one used for this RAMP risk analysis.

Accordingly, while the data we used in this RAMP report is the best information reasonably available, SCE will examine ways to modify existing tracking systems and reports to better inform future risk analyses.

C. Performance Metrics

SCE continues to collaborate with other utilities, industry organizations, and government entities to identify metrics that can be used to measure our physical security efforts. Internally, SCE utilizes a number of different performance metrics, including:

Table VIII-1 – Physical Security Performance Metrics

Metric	Description
Cold-Start Response Time	Cold starts are requests for security guard coverage that require immediate attention. This metric tracks the percentage of times security officers respond to (planned & immediate) cold start requests within a 4 hour timeframe.
Initial Incident Report	Short Messaging Service (SMS) is used for critical notifications and submitted to Corporate Security management for resolution. This metric tracks the percentage of initial notifications resolved within the 5 minutes of first reporting.
Security Project Milestone Adherence	Tracks project performance against scope, schedule, and cost.
Break/Fix Work Orders for Critical Facilities	Tracks the completion of break/fix notifications for critical facilities within the established period of time.

SCE will continue to use these performance metrics to mitigate physical security threats. Additional metrics we are considering for implementing in the future are:

- Electrical service interruption: cumulative customer-minutes interruption (CMI) caused by physical security incidents
- Time of recovery from outages caused by physical security incidents
- Cost of recovery from outages caused by physical security incidents
- Number of incidents associated with copper theft by geographic area
- Number of false or nuisance alarms

- Number of malfunctions of security equipment
- Number of incidents associated to vandalism, graffiti, or homelessness by geographic area

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Wildfire

Chapter 10

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

Southern California Edison (SCE) provides electric service to over five million customers in a 50,000 square-mile service area. Approximately 35% of this service territory is in High Fire Risk Areas (HFRA).[1] This chapter will address the risk of wildfire ignitions associated with SCE workers and assets. To perform this risk analysis, SCE developed a risk bowtie that includes risk drivers, triggering events, outcomes, and consequences. SCE also quantified the potential safety, reliability, and financial impacts resulting from this risk.

Wildfire mitigation measures have long been integral to our operational practices. SCE has several current controls in place that include, but are not limited to: our Vegetation Management Program, our Overhead Conductor Program (OCP), operational procedures (such as recloser blocking), and the recently introduced ester fluid-insulated Overhead Transformers. These programs help reduce the frequency or the impacts of wildfires.

SCE has evaluated existing controls and potential new mitigations to address this risk, and we have developed a Proposed Plan and two Alternative Plans. The Proposed Plan includes a portfolio of work that balances risk mitigation, execution feasibility, and cost-effectiveness. The plan leverages our existing controls, and includes new and expanded mitigations designed to reduce the risk of wildfires. Finally, as discussed throughout this chapter, this Proposed Plan aligns with SCE's Grid Safety and Resiliency Program (GS&RP) Application, A.18-09-002.

B. Scope

The scope of this chapter is defined in Table I-1.

Table I-1 – Scope of Chapter

In Scope	Ignition associated with SCE Overhead Distribution Equipment
Out of Scope	Ignition associated with SCE Transmission/Substation Equipment,[2] Ignitions not associated with SCE.

[1] The term "High Fire Risk Areas" refers to the locations in SCE's service territory that have been given a Tier 2 or Tier 3 designation in the most recent CPUC High Fire Threat District maps (CPUC Fire Maps). See D.17-12-024. The term also encompasses any additional locations that SCE had previously identified in its service area as high fire risk areas prior to the release of the most recent CPUC Fire Maps.

[2] In this chapter, SCE focuses on risks associated with SCE's distribution equipment because approximately 90 percent of all of the fires associated with electrical equipment in SCE's service area are related to distribution level voltages (33kV and below). However, some of the mitigation measures

C. Summary Results

Table I-2 summarizes the controls and mitigations included in this chapter, as well as the results of SCE's risk evaluation using SCE's Multi Attribute Risk Scoring (MARS) framework. As discussed in more detail below, the table shows that the MRR and RSE of the Proposed Plan is comparable to Alternative Plan #1 when examined in terms of mean results. The Proposed Plan has a higher MRR and a lower RSE than Alternative Plan #1 when examined in terms of tail average results.

This table also shows that the Proposed Plan has a lower MRR and a higher RSE than Alternative Plan #2 in terms of both mean and tail average results.

SCE discusses in detail in Sections V, VI, and VII the reasons why we recommend the Proposed Plan at this time, rather than Alternative Plan #1 or Alternative Plan #2.

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discussed in this Chapter will reduce fire risk for transmission facilities as well. These include, for example, situational awareness mitigation measures including HD cameras, weather stations, and advanced weather models (M7). SCE qualitatively discusses some direct safety risks associated with transmission and substation facilities in Appendix B of the RAMP Report. Going forward, SCE intends to perform more detailed quantitative analysis of transmission-related wildfire risks in future analyses.

Table I-2 – Summary Results (Annual Average over 2018-2023)[3]

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Overhead Conductor Program (Bare + Covered)	x		x
C1a	Overhead Conductor Program - (Bare Only)		x	
C2	FR3 Overhead Distribution Transformer	x	x	x
M1	Wildfire Covered Conductor Program	x		
M1a	Wildfire Covered Conductor Program (including covered and bare sections)		x	
M1b	Underground Conversion			x
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	x	x	x
M3	PSPS Protocol and Support Functions	x	x	x
M4	Infrared Inspection Program	x	x	x
M5	Expanded Vegetation Management	x	x	x
M6	Microgrids			x
M7	Enhanced Situational Awareness	x	x	x
M8	Fusing Mitigation	x	x	x
M9	Fire Resistant Poles (M1 Scope)	x		
M9a	Fire Resistant Poles (M1a Scope)		x	
M9b	Fire Resistant Poles (M1b Scope)			x
Mean (MARS)	*Cost Forecast ($ Million)*	$343	$303	$1,037
	Baseline Risk	6.9	6.9	6.9
	Risk Reduction (MRR)	1.3	1.2	1.3
	Remaining Risk	5.6	5.7	5.6
	Risk Spend Efficiency (RSE)	0.0037	0.0039	0.0013
Tail Average (MARS)	*Cost Forecast ($ Million)*	$343	$303	$1,037
	Baseline Risk	24.0	24.0	24.0
	Risk Reduction (MRR)	4.3	4.1	4.3
	Remaining Risk	19.7	19.9	19.7
	Risk Spend Efficiency (RSE)	0.0126	0.0134	0.0042

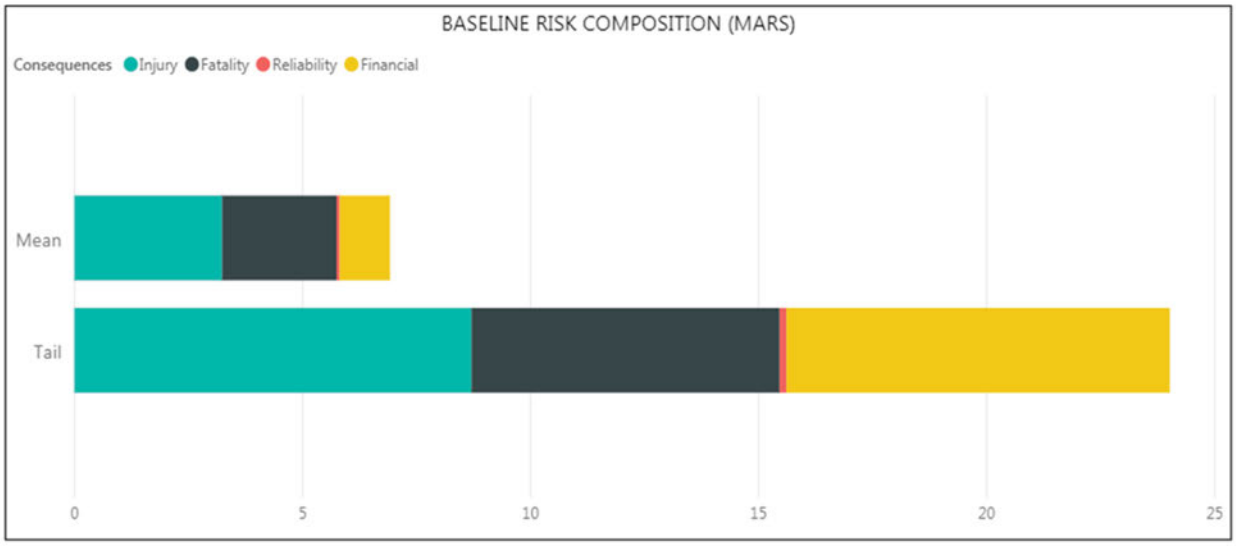
CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.
M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled this report, and are addressed in Section IV.
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

[3] The OCP controls (C1 and C1a) represent a small share of the conductor-related controls in the HFRA when considering the Wildfire Covered Conductor Program mitigations (M1, M1a and, M1b). In all three of the portfolios, the control is 9% of the total conductor-related scope.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-1 illustrates the baseline risk associated with Wildfire. The mean result is the average result across all simulations. The tail result is the average of the most extreme ten percent of simulations. In other words, the tail indicates lower-probability, higher-impact events. The color coding represents the contribution from each of the risk attributes analyzed in this RAMP report. This figure shows that safety (serious injuries and fatalities) constitutes the largest impact on both a mean and a tail-average basis. However, financial impacts become considerably more significant when evaluating this risk on a tail-average basis.

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS is 100.

II. Risk Assessment

A. Background

California is experiencing a sharp increase in the size of wildfires and the damage they cause. Unfortunately, 2017 was an historic year for wildfires in our state. Within SCE's service area, the Thomas Fire,[4] which occurred in December 2017, became the eighth most destructive wildfire in California since the early 1900s. Outside of SCE's service area, the Tubbs Fire[5] in October 2017 was notable for the number of fatalities and the time of year. As we moved into 2018, the Mendocino Complex fire,[6] which began in July of 2018, became the largest fire in California's history.

These three fires are examples of the increasing size and devastation of wildfires in California. In addition, the wildfire season has expanded to be a "year-round" fire season in California, constituting a "new normal."[7, 8]

Several factors contribute to the risk of wildfire and its consequences, including but not limited to an increase in construction in California's wilderness-urban interface areas, and the effects of climate change. The construction increase, primarily residential, expands the potential damage to property and loss of life due to wildfires. Nearly 35% of wildfires begin in this high-risk wildland-urban interface[9] where the risk of property damage and fatalities is greatest.

California's weather conditions are changing. Drought conditions have become more severe, and their durations are getting longer;[10] non-drought conditions are becoming shorter.

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[4] The Thomas Fire burned 281,893 acres between December 4, 2017 and January 12, 2018 destroying 1,063 structures, damaging 280 structures, injuring two firefighters, and causing two fatalities.
[5] The Tubbs Fire burned 36,807 acres between October 8, 2017 and October 31, 2017 destroying 5,643 structures, injuring one individual and causing 22 fatalities.
[6] As of September 5, 2018, the Mendocino Complex fire burned 459,123 acres, destroyed 280 structures, and caused 3 injuries and 1 fatality, in Northern California.
[7] Quote from Governor Edmund G. Brown's news conference on December 9, 2017 at the Ventura County Fairgrounds, after his tour of the fire areas.
[8] Marissa Clifford, *In California, It's Always Fire Season Now*, LA CURBED (June, 2018), *available at* https://la.curbed.com/2018/6/5/17428734/wildfires-calfornia-risk-prediction .
[9] Article gives further insight into wildfires started in the Wildland-urban interface. Schoennagel, Tania; Balch, Jennifer K.; Brenkert-Smith, Hannah; Dennison, Philip E.; Harvey, Brian J.; Krawchuk, Meg A.; Mietkiewicz, Nathan; Morgan, Penelope; Moritz, Max A. (2017-05-02). "Adapt to more wildfire in western North American forests as climate changes." *Proceedings of the National Academy of Sciences*. **114** (18): 4582–4590. http://www.pnas.org/content/114/18/4582.
[10] Scott Stephens et al., Drought, Tree Mortality, and Wildfire in Forests Adapted to Frequent Fire, 68

For example, severe drought conditions led to Governor Brown proclaiming a State of Emergency on January 17, 2014; Governor Brown "directed state officials to take all necessary actions to prepare for the drought conditions."[11] On April 25, 2015, Governor Brown issued Executive Order B-29-15 that proclaimed a Continued State of Emergency and, among other things, ordered significant water conservation measures. Weather conditions, such as those that propagate drought conditions, are contributing to the increase in the number of days California is under extreme fire danger and to our state facing a year-round fire season with constant wildfire risk.[12]

The Commission has addressed wildfire risk, and the risks from wildfires associated with utility infrastructure, in Rulemaking R.15-05-006. The Commission has approved revised fire threat maps and increased inspection and vegetation management requirements in these areas. Beyond these efforts, SCE is proposing additional measures to harden and upgrade our system to further prevent utility-associated wildfires and to further mitigate system impacts when a fire occurs. These measures are included in SCE's GS&RP Application.

The risk analysis presented in this chapter aligns with the GS&RP filing.[13] Both filings utilize similar underlying data and assumptions regarding risk drivers and mitigation effectiveness. This RAMP chapter quantifies the risk reduction benefits of mitigations in the GS&RP portfolio. However, there are necessarily certain inherent differences in analysis methodologies. Generally speaking, these differences occur because:

- Costs in RAMP are represented in nominal dollars, while the costs in the GS&RP filing are represented in 2018 constant dollars. This will create a variance in total forecast. However, the underlying scope identified for the various mitigations for specific time periods will be the same.
- RAMP requires considering the forecast period of 2018-2023. The GS&RP application is intended to justify the program from the filing date of 9/10/2018 through year-

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BIOSCIENCE 77, 78 (Feb. 2018), available at https://www.fs.fed.us/psw/publications/fettig/psw_2018_fettig002_stephens.pdf

[11] Governor Brown's State of Emergency Proclamation, January 17, 2014, *available at* https://www.gov.ca.gov/2014/01/17/news18368/.
[12] See Chapter 12, Climate Change for more details.
[13] For a detailed discussion on the alignment between RAMP and the GS&RP riling, please refer to WP Ch. 10, pp. 10.47-10.51 *(RAMP to GSRP Comparison Workpaper).*

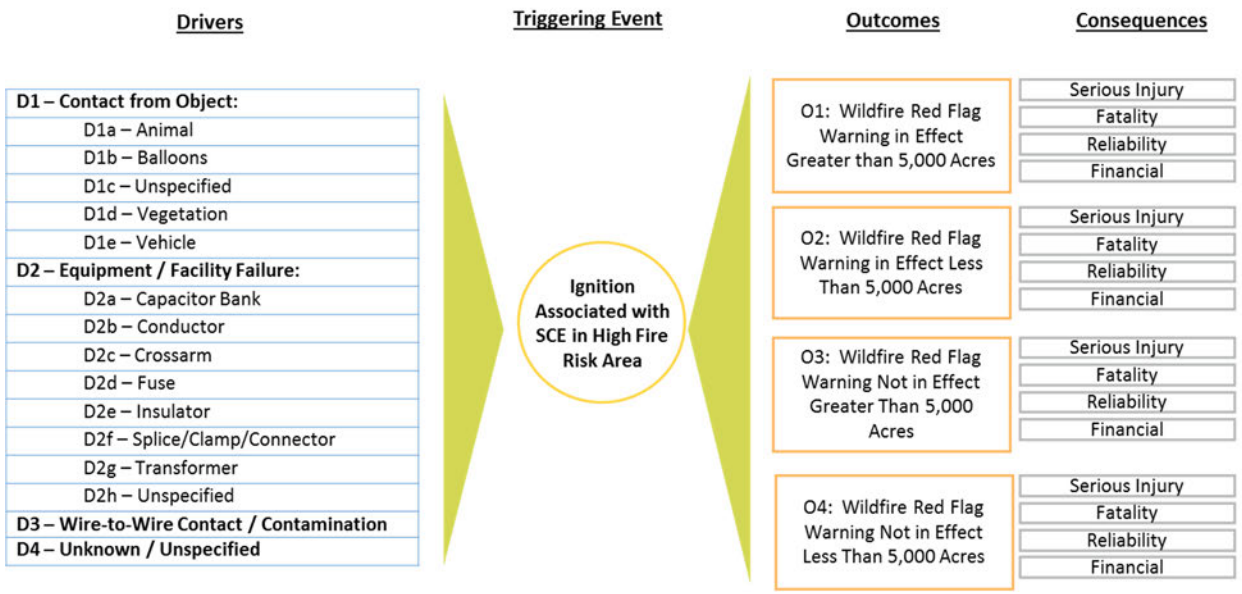
end 2020. This drives a difference in start and end dates for both filings, and necessarily causes the forecasts to vary.

- The RAMP analysis only counts benefits that occur during 2018-2023, while GS&RP considers benefits for all future years. In section V below, we discuss in greater detail the difference in benefits when the long-term benefits are included, compared to restricting the benefits period to years 2018-2023.
- The proposed RAMP portfolio excludes Wildfire Mitigation Program Study Costs. These costs are intended to allow SCE to explore new technologies to reduce future risk.
- The wildfire risk model SCE developed for RAMP evaluates wildfire events based on size ("more than" or "less than or equal to" 5,000 acres) and whether the wildfire event occurs on days when a Red Flag Warning[14] was either "in effect" or "not in effect." The GS&RP conductor-based comparative analysis does not distinguish between these differences.

Figure II-1 below summarizes the risk bowtie that SCE used to model wildfire risk in this chapter.

[14] Red Flag Warning is a term used by fire-weather forecasters to call attention to limited weather conditions of particular importance that may result in extreme burning conditions. It is issued when it is an ongoing event, or when the fire weather forecaster has a high degree of confidence that Red Flag criteria will occur within 24 hours of issuance. Red Flag criteria occurs whenever a geographical area has been in a dry spell for a week or two, or for a shorter period, if before spring green-up or after fall color, and the National Fire Danger Rating System (NFRDS) is high to extreme and the following forecast weather parameters are forecast to be met: 1) a sustained wind average 15 mph or greater; 2) relative humidity less than or equal to 25 percent; and 3) a temperature of greater than 75 degrees F. In some states, dry lightning and unstable air are criteria. A Fire Weather Watch, for conditions that may exist within 12-72 hours, may be issued prior to the Red Flag Warning.

Figure II-1 – Risk Bowtie



B. Driver Analysis

To identify the drivers that caused the triggering event (ignition associated with SCE in High Fire Risk Area), SCE analyzed the fires that occurred in SCE's service area between 2015 and 2017 that were reportable to the CPUC.[15] This analysis yielded four major categories of drivers:

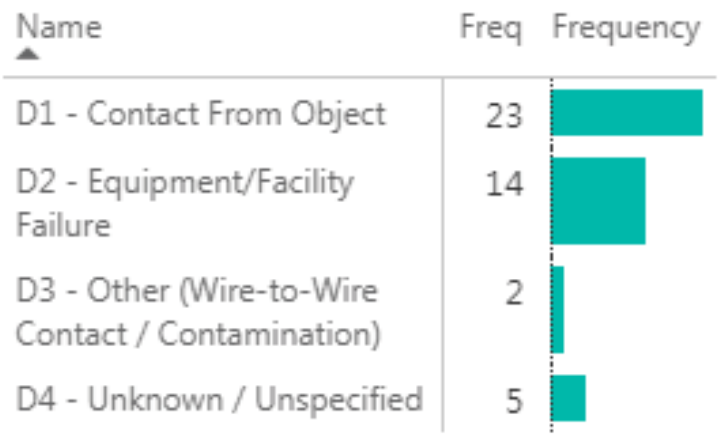
1. D1 - Contact From Object, which includes external factors that cause SCE's equipment to fail, or to function as an ignition source to foreign material;
2. D2 - Equipment/Facility Failure, which includes events caused by failure of SCE equipment, independent of events listed in D1;
3. D3 - Wire-to-Wire Contact/Contamination; and,
4. D4 – Unknown/Unspecified.

To develop the number of events for each driver, SCE analyzed the ignition events identified above to exclude events that did not occur in HFRA. For purposes of risk modeling, SCE rounded the three-year averages for each driver to the nearest whole number. This rounding resulted in some low-frequency drivers having a three-year average of zero, and does not impact the risk analysis results. SCE identified four drivers, as shown in Figure II-2 below. As detailed below, we

[15] Per D.14-02-015, reportable fire events are any events where utility facilities are associated with the following conditions: (a) a self-propagating fire of material other than electrical and/or communication facilities; (b) the resulting fire traveled greater than one linear meter from the ignition point; and (c) the utility has knowledge that the fire occurred.

were able to subdivide two of these drivers (D1 and D2). This greater granularity helped us better understand the causes of this risk.

Figure II-2 – 2018 Projected Driver Frequency[16]



SCE performed analyses that correlated fire events to faults on SCE's distribution system. These faults, which have historically occurred from all drivers and sub-drivers shown in Figure II-1, can result in arcing during the fault event. When this arcing contains sufficient energy—given local conditions such as temperature, humidity, and nearby fuel source—ignition can result and lead to a wildfire.[17] Figure II-3 illustrates how the two most prevalent categories of faults can lead to wildfires.

[16] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).
[17] The concept of fault energy can be described as the electric system's natural reaction to fault conditions. Dominant factors for fault energy are the duration and the magnitude of electrical current during a fault. In essence, reducing fault energy helps reduce the probability of ignition.

Figure II-3 – Illustrative Event Diagram for Wildfire Ignitions Originating from Faults on Overhead Circuits

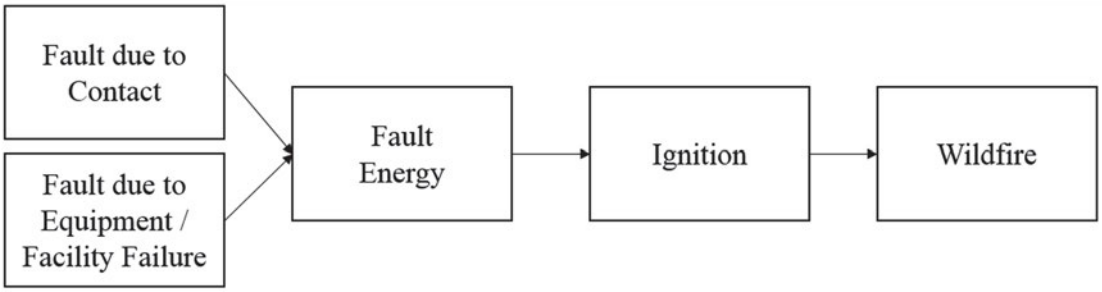


Table II-1 breaks down the different driver categories used within our risk modeling efforts. Table II-2 and Table II-3 break down the sub-drivers of Contact from Object and Equipment/Facility Failure, respectively.

Table II-1 – Driver by General Category

	Annual Count				
Suspected Initiating Event	**2015**	**2016**	**2017**	**3 Year Average (Rounded)**	**% Total of All Drivers**
D1 - Contact From Object	23	21	26	23	52%
D2 - Equipment / Facility Failure	10	21	9	14	32%
D3 - Other (Wire to Wire Contact / Contamination)	4	0	2	2	5%
D4 - Unknown / Unspecified	7	2	7	5	12%
Total	**44**	**44**	**44**	**44**	**100%**

Table II-2 – D1 (Contact from Object) Sub-Driver Statistics

	Annual Count				
D1 - Contact From Object	**2015**	**2016**	**2017**	**3 Year Average (Rounded)**	**% Total of All Drivers**
D1a - Animal	7	5	3	5	11%
D1b - Balloons	2	3	9	5	11%
D1c - Other	2	5	3	3	7%
D1d - Vegetation	8	6	8	7	16%
D1e - Vehicle	4	2	3	3	7%
Total	**23**	**21**	**26**	**23**	**52%**

Table II-3 – D2 (Equipment/Facility Failure) Sub-Driver Statistics

	Annual Count				
D2 - Equipment / Facility Failure	**2015**	**2016**	**2017**	**3 Year Average (Rounded)**	**% Total of All Drivers**
D2a - Capacitor Bank	0	1	1	1	2%
D2b - Conductor	2	8	2	4	9%
D2c - Crossarm	0	0	1	0	0%
D2d - Fuse	0	1	0	0	0%
D2e - Insulator	1	2	2	2	5%
D2f - Splice/Clamp/Connector	3	4	1	3	7%
D2g - Transformer	1	1	1	1	2%
D2h - Other	3	4	1	3	7%
Total	**10**	**21**	**9**	**14**	**32%**

As we described above in section II-B, SCE ascertained the drivers (i.e., the causes of the fire events) by analyzing the fires that occurred between 2015 and 2017 in SCE's service territory that were reportable to the Commission. The drivers and sub-drivers presented in these tables are described below.

1. D1 – Contact from Object

a. D1a – Contact from Object – Animal

Many animals come in contact with SCE's distribution facilities on a daily basis. When an animal or bird is sitting or walking on an overhead conductor, its feet are at the same voltage potential[18] and the animal or bird will not be electrocuted. However, electrocution occurs when one of the animal's feet comes into contact with an object at a different potential (such as another conductor or a grounded object like a tree) while the other foot (or feet) remains on the conductor. Electrocution results in severe injury, or death, to the animal and damage to the conductor and other electrical equipment impacted by the fault. Additionally, the remains of the animal itself can ignite and become a fire risk.

b. D1b – Contact from Object - Balloons

Foil-lined or metallic balloons can potentially damage overhead electrical equipment because of their conductivity. Current California law[19] has recognized this concern, and requires that all helium-filled foil balloons be weighted, to prevent escape and potential contact with overhead electrical facilities. When a metallic balloon contacts overhead lines it can create a short circuit. This can cause a large power arc, resulting in circuit damage, overheating, fire, or an explosion.

[18] Voltage potential is a measure of the propensity for electricity to travel from one point to another.
[19] California SB 1990, "Balloon Law."

c. D1c – Contact from Object – Other

Contact from other unspecified objects, or foreign material, include items such as tennis shoes, chains, gunshots, ice, crop dusting and other items. Each object has the potential to cause different types of failures, ranging from a fault to equipment failure, or ignition of the object itself.

d. D1d – Contact from Object – Vegetation

Even with SCE's existing vegetation management programs (see Compliance Control (CM1) – Vegetation Management in Section III), vegetation can still make contact with overhead conductor and cause an ignition and/or a wire down event. Branches or palm fronds can break or come loose from the main tree and fall, or can be blown by wind into overhead conductor. Besides causing faults, these branches and palm fronds can ignite and become additional fire risks.

Branches or palm fronds that blow into overhead conductor can come from trees in excess of 200 feet away depending on the wind and terrain. This distance is well beyond required clearances. Additionally, vegetation growth rates can vary, and trees or other vegetation may grow faster than anticipated between scheduled inspections. Vegetation can grow into lines and make contact, despite SCE's efforts to inspect and maintain clearances throughout our 50,000 square-mile area.

e. D1e – Contact from Object – Vehicle

Vehicles can come into contact with SCE poles and other aboveground equipment, resulting in damage to the pole and/or equipment.[20] Vehicle impact causes SCE's equipment to fail in many ways: conductor or other equipment falling to the ground; conductor slapping together causing a fault; or the pole falling to the ground and taking the conductor with it. Sometimes, the failure can result in a wildfire.

2. D2 – Equipment / Facility Failure

a. D2a – Equipment / Facility Failure – Capacitor Bank

SCE uses capacitor banks to compensate for reactive power losses and to regulate voltages on the distribution system. Approximately 85% of all distribution capacitor banks on the SCE system are installed on overhead circuits. Failing capacitor banks may create

[20] Although not covered in this risk analysis, SCE is sensitive to the fact that there can also be injury to the driver and damage to the vehicle.

arcing from the associated equipment, and the released electrical energy can be enough to ignite fires, either at ground level or at pole-top level.

b. D2b – Equipment/Facility Failure – Conductor

When an energized conductor fails and hits the ground, wildfire ignition can occur. In general, there are two ways overhead conductor can experience failure.

The first is when the system's short circuit duty (SCD) exceeds a conductor's rating. Generally, SCD indicates the relative strength of an electrical system, typically measured by the current (in amps) that the system can supply when fault conditions occur. If, at any given point in the system, fault current exceeds the conductor's ability to withstand it, then fault conditions can damage the conductor and lead to conductor failure. Vintage small conductor is especially vulnerable to damage during fault conditions, because it typically possesses a lower conductor rating, or current carrying capacity, compared to larger conductor.

The second is conductor fatigue. Conductor fatigue refers to the decrease in overhead conductor's ability to withstand forces experienced during operational conditions. For overhead wire, the likelihood of fatigue-related failures tends to increase over time, as the conductor is exposed to longer periods of operational stress. For example, overhead conductors have both a normal long-term thermal rating and a higher short-term emergency thermal rating. Emergency thermal ratings are used to accommodate higher levels of load. These ratings are typically relied on during abnormal operating conditions, such as when transferring customers between adjacent circuits in order to restore service as rapidly as possible during circuit outage conditions.

Beyond the operating conditions described above, the conductors could also be exposed to very high-magnitude short circuit current from time to time when there is a fault condition further downstream in the circuit. Even though these short circuit currents are typically very brief in duration, the extremely high current level can result in a rapid increase in localized temperature of the conductor. This can start to change the molecular structure of the conductor material; the result is a significant and permanent reduction in the mechanical strength of the conductor. When coupled with other induced mechanical loading such as wind, vibration, and other environmental factors, this will contribute to the conductor experiencing fatigue-related failures at some point in its lifetime.

c. D2c – Equipment/Facility Failure – Crossarm

Crossarms are mounted on distribution poles and used to support overhead conductor or other pieces of overhead distribution equipment. As crossarm pieces weaken or

deteriorate over time, either the crossarm can break or the bracket that attaches the crossarm to the pole can fail. In either case, conductor can come into contact with other conductors, the pole, other pieces of electrical equipment, or the ground. This may lead to the causal fault chain shown in Figure II-3 above, with the end result being a wildfire.

d. D2d – Equipment/Facility Failure – Fuse

Fuses are protective devices designed to clear system faults by interrupting fault current and de-energizing circuits downstream of the fuse. Fuses are essentially thermal devices designed to melt at a specified current in a specified time. Fault clearing times, or the time it takes a fuse to activate, generally depend on both current and time. Faster fault clearing typically occurs for higher levels of fault current, while slower fault clearing occurs for lower levels of fault current.

When the fuse element melts, it must be able to do so without causing catastrophic failure of the fuse itself. Such fuse failures can cause prolonged fault conditions, equipment damage, or fire ignition.

e. D2e – Equipment/Facility Failure – Insulator

Insulators provide mechanical support to energized conductors and maintain electrical isolation between energized conductors and grounded structures such as poles.

Insulators can fail in various ways. For example, insulators, especially older glass or porcelain insulators, can be broken by contact from a wide range of foreign objects, from hail storms to gunshots. The mounting part of insulators that connects the insulator to the crossarm can deteriorate over time and break or come loose. The tie that connects the energized conductor to the insulator can also come loose; this can damage the conductor over time or detach completely from the conductor. In any of these cases, the insulator failure leads to loss of mechanical support for the conductor. This causes the conductor to come into prolonged contact with the pole, with other equipment, or with the ground. Any such contact can eventually lead to an ignition.

f. D2f – Equipment/Facility Failure – Splice/Clamp/Connector

Splices, clamps, and connectors are three different devices used to connect overhead conductor. Overhead conductor, or wire, is attached to other equipment with a connector or clamps. Spans of conductors are connected to other spans of conductor with a splice. These devices can degrade due to exposure to the elements, and can be damaged as the result of faults on the circuit. Faults on a circuit and the resulting fault current can cause these devices to overheat and melt, causing the overhead conductor to fall to the ground. Failures of

splices can result in a conductor coming down and faulting due to contact with other equipment, objects, or the ground.

g. D2g – Equipment/Facility Failure – Transformer

Distribution transformers can fail for several reasons. One common reason for transformer failures is heavy transformer loading over extended periods of time. Such conditions cause transformers to heat up. This prolonged loading at or near the transformer's rated loading condition can also shorten the useful life of the insulation material. This increases the probability of failure. This problem is exacerbated during extended heat wave conditions, because the equipment does not have the necessary time to cool.

Historically, SCE has experienced a high number of transformer failures during heat storms. The exterior shell of the transformer can deteriorate over time and leak oil, which can also lead to failure. Moreover, because transformers contain oil, when transformers overheat they can fail violently and cause a fire.

h. D2h – Equipment/Facility Failure - Unspecified

This driver category captures wire-down events where field personnel have attributed the event to equipment failure, but the specific equipment detail is not provided.

3. D3 – Wire-to-Wire Contact / Contamination

Wire-to-wire contact can occur during high winds or during conditions where third parties make contact with poles or conductors. The factors that can contribute to wire-to-wire contact include the phase spacing, pole geometry, and conductor tension on each phase of the circuit. When wire-to-wire contact occurs, fault conditions can damage the conductor and cause conductor failure.

Contamination is a phenomenon typically associated with the insulators that support the conductor in a distribution circuit. Contamination-related flashovers typically begin when some type of airborne contaminant combines with moisture from fog, rain, or dew and collects on the surface of insulators. These contaminants can begin to conduct current across the insulators. Unless corrective action is taken, this current can cause the insulator to not perform as intended, resulting in a "flashover." Such flashovers can cause conductor or insulator damage and can lead to a wire-down.

4. D4 – Unknown / Unspecified

Unknown includes incidents where the cause was not identifiable. An example could be a fault on the system where an object made contact with a line but was subsequently blown or dispersed away from the line before SCE personnel arrived at the location.

C. Triggering Event

SCE utilized one triggering event related to wildfire risk. As shown in Figure II-1, this triggering event is "Ignition Associated with SCE in High Fire Risk Areas." This single triggering event can result from the many drivers discussed above and can lead to the outcomes and consequences described below.

D. Outcomes & Consequences

SCE identified four outcomes for the wildfire triggering event as shown in Figure II-1. These four outcomes are based on Red Flag Warnings and the size of the fire. SCE used the Red Flag Warning days because of the higher fire risk during those events and SCE's operating procedures when a Red Flag Warning is in effect within SCE's service area.

SCE also distinguished between fires greater than 5,000 acres and less than 5,000 acres. SCE used the 5,000 acre cutoff to distinguish between large fires with significant safety, financial, and reliability consequences, and smaller fires with lesser consequences. This size cutoff aligns with the largest size classifications for ignitions reported to the Commission per D.14-02-015. Additionally, SCE observed that all fires recorded by CalFire with a cause of "Electrical Power" from 2007-2017 showed recorded fatalities only for large fires greater than 5,000 acres.[21]

To show the likelihood of each outcome occurring, SCE analyzed the fires that occurred in SCE's HFRA service area between 2015 and 2017 that were reportable to the CPUC. Fire size is tracked as part of this CPUC reporting.[22] SCE analyzed meteorological data to identify which fires occurred during Red Flag Warnings. The results are shown for each individual outcome in Figure II-4 below.

[21] The California Department of Forestry and Fire Protection (CalFire) publishes an annual Wildfire Activity Statistics report, commonly known as the "Redbook."
http://www.fire.ca.gov/fire_protection/fire_protection_fire_info_redbooks

[22] For Outcome O3 – "Wildfire Red Flag Warning Not in Effect Greater than 5,000 Acres," SCE's data reported zero fires with this outcome. For analysis purposes, SCE included a 0.19% probability, based on the ratio of CalFire incidents occurring on Red Flag Days compared to non-Red Flag Days for fires greater than 5,000 acres. Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).

Figure II-4 – 2018 Outcome Likelihood[23]

Name	%	Percent
O1 - Wildfire Red Flag Warning in Effect Greater than 5,000 Acres	0.8 %	
O2 - Wildfire Red Flag Warning in Effect Less Than 5,000 Acres	31.0 %	
O3 - Wildfire Red Flag Warning Not in Effect Greater Than 5,000 Acres	0.2 %	
O4 - Wildfire Red Flag Warning Not in Effect Less Than 5,000	68.1 %	

For each outcome, SCE identified applicable consequences, and modeled these consequences using statistical distributions. For many consequences modeled in this chapter, SCE developed a distribution based on CalFire's published fire statistics, with cause classifications assigned by CalFire as "Electrical Power," which is defined as "Fire ignited by electrical power distribution or transmission."[24]

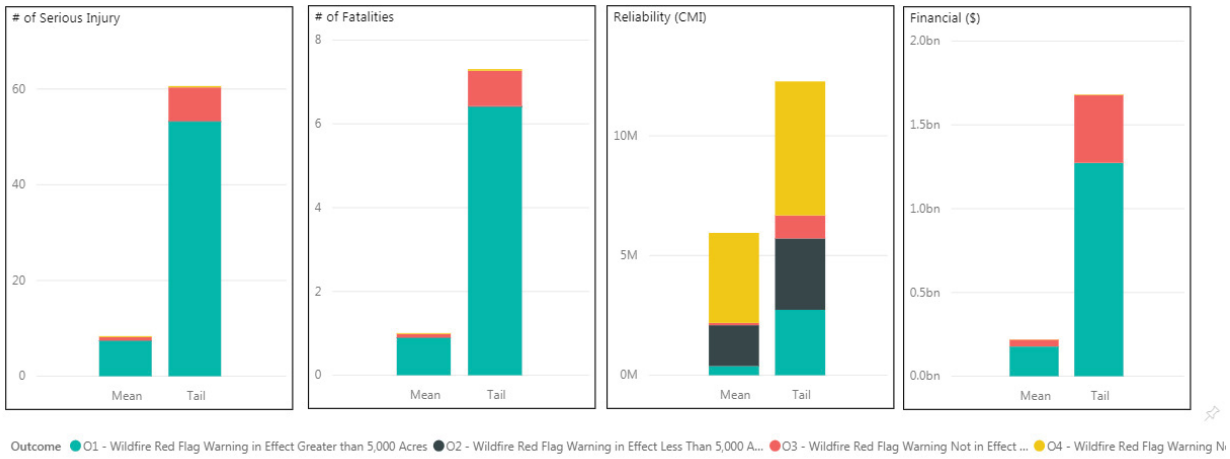
Please see Chapter 2 (Risk Model Overview) for additional detail regarding the outcome and consequence distribution modeling process. The sections that follow detail the data used to inform the development of these distributions.[25]

The wildfire events included within CalFire data encompass events in SCE's service area, as well as a number of events that occurred outside our service area but within California. The CalFire data population of fires associated with Electrical Power in SCE's service is relatively small, especially for fires greater than 5,000 acres. By including events from areas outside of SCE's service area, SCE could provide a more robust wildfire risk analysis. SCE's consequence modeling utilizes this CalFire data for fatalities, structures destroyed, and acres burned.

Figure II-5 illustrates the composition of the modeled baseline risk in terms of each consequence dimension, shown in natural units, on both a mean and tail-average basis. The sections that follow examine the inputs used to derive these results. Figure II-5 shows that O1 (Red Flag Day, >5,000 Acres), accounts for most of the serious injury, fatality, and financial impacts of this risk. Conversely, O4 (Non-Red Flag Day, <5,000 Acres) accounts for the majority of reliability impacts of this risk.

[23] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*).
[24] http://www.fire.ca.gov/downloads/redbooks/2016_Redbook/2016_Redbook_FINAL.PDF
[25] Note that SCE includes wildfire consequences from across California to develop these distributions, due to the relatively low number of large fires in SCE service area.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (Natural Units)



1. O1 – Wildfire Red Flag Warning In Effect Greater Than 5,000 Acres

This outcome includes wildfire events greater than 5,000 acres that occur while a Red Flag Warning is in effect. Approximately 0.8% of wildfire events we evaluated result in this outcome. Wildfires that occur during Red Flag Warnings have the potential to be more aggressive and faster-moving fires. This is due to environmental conditions such as low relative humidity, strong winds, dry fuels, the possibility of dry lightning strikes, or any combination of these factors. These large fires can be more dangerous to people and more destructive to property, vegetation, and wildlife.

We summarize potential consequences from O1 on an annualized basis in Table II-4.[26] Serious injuries and fatalities are associated with firefighters and members of the public that could be physically injured during a wildfire event. Financial costs are associated with property damage, firefighting costs, and land restoration costs. Reliability reflects outage events associated with fires. Consequences are shown in natural units (NU), which are defined as Serious Injuries and Fatalities for Safety, Customer Minutes of Interruption (CMI) for Reliability, and US Dollars for Financial. On a mean basis, this outcome is modeled to result in 7.4 serious injuries, 0.89 fatalities, 380,000 customer minutes of interruption, and $177 million in financial consequences. Similarly, on a tail-average basis, this outcome is modeled to result in 53.2

[26] Please refer to WP Ch. 10, pp. 10.1-10.8 (*Baseline Risk Assessment*), and WP Ch. 10, p. 10.52 *(SME Qualifications)* for additional detail on model inputs and rationale.

serious injuries, 6.4 fatalities, 2.7 million customer minutes of interruption, and $1.3 billion in financial consequences. The similar tables for Outcomes 2 – 4 also display this type of information for their respective consequences.

Table II-4 – Outcome 1 (Wildfire Red Flag Warning In Effect Greater Than 5,000 Acres): Consequence Details[27,28]

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	7.4	0.89	380,083	$177,046,382
	NU - Tail Avg	53.2	6.41	2,731,289	$1,272,262,531

2. O2 – Wildfire Red Flag Warning In Effect Less Than 5,000 Acres

This outcome includes wildfire events less than 5,000 acres that occur while a Red Flag Warning is in effect. Approximately 31.0% of wildfire events evaluated result in this outcome. Table II-5 summarizes the baseline consequences across risk dimensions for this outcome. The table also summarizes the source data used to develop consequence distributions for this outcome.

[27] As of October 19th, 2018, CalFire Redbook data had not been released for 2017. However, several significant 2017 fires have been publically reported by CalFire in news releases to be caused by Electrical Power, and included within this analysis. Please refer to Section VIII-B for additional description of data availability.

[28] http://www.usfa.fema.gov/downloads/xls/statistics/us_fire_loss_data_sets_2006-2015.xlsx

Table II-5 – Outcome 2 (Wildfire Red Flag Warning In Effect Less Than 5,000 Acres): Consequence Details

Outcome 2		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	0.1	0.01	1,709,923	$689,707
	NU - Tail Avg	0.2	0.02	2,983,897	$1,205,427

3. O3 – Wildfire Red Flag Warning Not In Effect Greater Than 5,000 Acres

This outcome includes wildfire events greater than 5,000 acres that occur while a Red Flag Warning is not in effect. Approximately 0.2% of wildfire events evaluated result in this outcome. Table II-6 summarizes the baseline consequences across risk dimensions for this outcome. The table also summarizes the source data used to develop consequence distributions for this outcome.

Table II-6 – Outcome 3 (Wildfire Red Flag Warning Not In Effect Greater Than 5,000 Acres): Consequence Details

Outcome 3		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	0.7	0.09	96,120	$40,484,491
	NU - Tail Avg	7.0	0.84	961,196	$404,844,913

4. O4 – Wildfire Red Flag Warning Not In Effect Less Than 5,000 Acres

This outcome includes wildfire events less than 5,000 acres that occur while a Red Flag Warning is not in effect. Approximately 68.1% of wildfire events evaluated result in this outcome. Table II-7 summarizes the baseline consequences across risk dimensions for this outcome. The table also summarizes the source data used to develop consequence distributions for this outcome.

Table II-7 – Outcome 4 (Wildfire Red Flag Warning Not In Effect Less Than 5,000 Acres): Consequence Details

Outcome 4		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	To estimate serious injuries, a ratio was developed between serious injuries and fatalities. Based on National Fire Protection Association Database from 2010-2014, a ratio of 8.3:1 was used.	Based on Fatalities from Electric Power Fires as reported by Calfire from 2007-2017	From SCE ODRM Database, actual wildfire outage events were analyzed.	Estimated unit costs per structure destroyed and acre burned were developed using national insurance databases, national firefighting cost data, and restoration cost studies. Acreage and structure quantities were based on data as reported by CalFire.
Model Outputs	NU - Mean	0.2	0.02	3,760,369	$1,516,932
	NU - Tail Avg	0.3	0.04	5,596,130	$2,261,676

III. Compliance & Controls

SCE has programs and processes in place today that serve to reduce the frequency of the risk materializing, or the impact level of a risk event should it occur. These activities are summarized in Table III-1, and discussed in more detail thereafter.

Table III-1 – Inventory Compliance & Controls[29,30,31]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Cost ($M)	
					Capital	O&M
CM1	Vegetation Management	Not Modeled	Not Modeled	Not Modeled	$0.0	$84.3
C1	Overhead Conductor Program (Bare + Covered)	D1a, D1b, D1d, D2b, D2f	-	-	$138.7	$0.0
C1a	Overhead Conductor Program - (Bare Only)	D2b, D2f	-	-	$138.7	$0.0
C2	FR3 Overhead Distribution Transformer	D2g	-	-	$0.0	$0.0

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.

A. CM1 – Vegetation Management

Vegetation Management includes pruning and removing trees that are in proximity to transmission and distribution high voltage lines. Vegetation Management also encompasses weed abatement around select overhead structures that may pose a hazard to power lines. These activities are mandated by regulation. This compliance-related work is distinct from the Expanded Vegetation Management mitigation developed and requested in the GS&RP mitigation portfolio, which although absolutely critical, is not expressly required by rule or regulation at this time. This Expanded Vegetation Management is represented in M5.

SCE manages vegetation in accordance with several regulations, including General Order (GO) 95 Rules 35 and 37, Public Resources Code Sections 4292 and 4293, and FERC FAC-003-2. SCE engages approved contractors to trim and remove trees and weeds, and engage in other vegetation management activities that comply with these requirements.

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[29] Within control and mitigation numbering, "a" and "b" designations indicate a change to a subset of overall program configurations. For example, the C1a OCP control explores the reversal of a standards change that is planned for 2020 to utilize covered conductor across all OCP scope in HFRA. M1a and M1b explore covered or bare conductor options in a subset of HFRA. 2017 recorded costs for OCP are duplicated for C1 and C1a as SCE has just one OCP program in the recorded period.
[30] Please refer to WP Ch. 10, pp. 10.9-10.26 (*RAMP Mitigation Reduction*) and WP Ch. 10, pp. 10.27-10.42 (*Mitigation Effectiveness Workpaper*).
[31] Control C2 does not show recorded costs, since it is associated with incremental costs for a change of standard for an existing program.

All of the trees in inventory are inspected annually. During these inspections, any trees or vegetation that need to be remediated to maintain the required distances from high-voltage lines are then scheduled to be pruned or removed. In addition, hazard trees, such as overhangs in HFRA, and damaged or diseased trees are also identified for pruning or removal. Sometimes we must trim trees more frequently to continue to meet the Commission's requirements for tree-to-line clearances between annual trim cycles. Fast-growing species, or trees in areas designated as high-risk for wildfires, may need more frequent pruning to meet the Commission standards.

Besides the vegetation management efforts described above, SCE also removes dead, dying, and diseased trees impacted by Bark Beetle infestation or resulting from California's Drought Order. Because of the drought emergency, SCE increased work activities associated with inspecting and removing dead, dying or diseased trees that could fall on or contact SCE's electrical facilities. Unlike trees located near power lines that must be trimmed to prevent encroachment, large dead or dying trees can be located outside of the right-of-way and still fall into power lines. This significantly increases the number of trees that can pose a hazard to our customers and the communities we serve. The estimated number of dead trees statewide is estimated at over 129 million, with over 14 million dead trees in high-hazard zones.[32]

B. C1 and C1a – Overhead Conductor Program (OCP)

C1 and C1a contemplate the benefit of deploying SCE's OCP program in HFRA. C1 captures the benefit of deploying OCP in HFRA using covered conductor.[33]

C1 will initially leverage bare conductor from 2018-2020 and transition to covered conductor for 2021-2023. SCE implemented a standards change in July 2018 to require new OCP projects in HFRAs to use covered conductor, which will provide additional wildfire risk benefits compared to bare conductor. Standards changes are applied to all new designs initiated after the standard is published. Because standards do not apply retroactively, inflight projects at various stages of completion with operating dates as late as 2020 will be built with bare conductor in HFRAs.

[32] Source: http://calfire.ca.gov/communications/downloads/newsreleases/2017/CAL%20FIREandU.S%20ForestAnnouce129MillionDeadTrees.pdf

[33] Please see Section IV.A for a more detailed description of covered conductor.

C1a captures the benefit of deploying OCP in HFRA using only bare conductor for the entire period 2018-2023. Covered conductor is described in more detail in Section IV – Mitigations.

In SCE's 2018 General Rate Case (GRC),[34] we proposed the OCP as a new program to address the public safety risk associated with wire-down events. SCE's OCP includes both reconductoring and installation of branch line fuses (BLFs). When OCP projects are performed in HFRA, these projects also will have wildfire risk reduction benefits as well.

Reconductoring and branch line fusing are intended to target and remedy overhead conductor susceptible to exceeding its short circuit duty rating.[35] The OCP also addresses damaged conductors using visible corrosion detection, and evaluates splice counts on the line as indicators of prior damage. As part of OCP, we also address crossarms, poles, connection hardware, and other damaged equipment along the path of the conductor being remediated.

Historically, SCE's distribution circuits were designed with larger conductor closer to the substation (feeding the circuit) and progressively smaller conductors as one proceeds further from the substation. This design approach was based on economics principles, and the fact that a circuit carries less current as it moves away from the substation.

The smaller conductor, when installed, was sized appropriately for the load. However, this smaller conductor is also inherently more susceptible damage from contact with metallic balloons, animals, vegetation, and other drivers listed in Table II-2 as the available SCD increased over time due to system upgrades. By replacing this smaller conductor with larger conductor, we reduce the risk of failure.

Installing branch line fuses protects against fault energy-related conductor failure. Fusing a line limits the amount of energy delivered to a fault. It does so by interrupting the current faster than the next upstream device, often the circuit breaker at the substation, keeping the conductor within its SCD rating. SCE's OCP includes fusing tap lines to mitigate the risk of overhead conductor failure.

[34] See SCE's Test Year 2018 GRC, A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 47-51.
[35] When reconductoring, SCE uses a minimum wire size of 1/0 Aluminum Conductor Steel Reinforced (ACSR), with 1/0 ACSR used predominately for tap lines, and 336 ACSR used predominately for main line sections.

1. Drivers Impacted

The OCP (C1) impacts Driver D1 (Contact from Object) with the covered conductor standards change starting in 2021,[36] and also impacts Driver D2 (Equipment Cause) for all years over the 2018-2023 RAMP period.[37] The OCP (C1a) impacts only Driver D2, for all years over the 2018-2023 RAMP period.[38]

Based on engineering analysis and demonstrated material performance, replacing small wire with large wire will increase the conductor's ability to withstand higher short circuit duty. This makes the conductor less susceptible to failure from faults on the line. Similarly, installing BLFs will reduce the risk of failure by quickly interrupting the flow of current when fault conditions are present.

Reconductoring with bare wire *will not* reduce the frequency of contact from object faults. Contact from objects are external, or random, events that will continue to occur regardless. However, reconductoring with covered conductor *will* reduce the frequency of contact from object faults.

2. Outcomes & Consequences Impacted

The OCP (C1 and C1a) will not directly impact outcomes or consequences in the risk model.

C. C2 – Ester Fluid (FR3) Overhead Distribution Transformer

This control will replace existing overhead distribution transformers (which are primarily filled with mineral oil) with overhead distribution transformers filled with ester fluid. Envirotemp FR3 Fluid, or ester fluid, is a derivative of renewable vegetable oil, and has a higher flash point rating than mineral oil.[39] This decreases the likelihood that the fluid and/or fluid vapors will ignite and stay lit during a catastrophic event. This in turn reduces the chance of igniting surrounding brush and/or other flammable material surrounding the pole and transformer.

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[36] The specific sub-drivers impacted include D1a (Contact From Object – Animal), D1b (Contact From Object – Balloons), and D1d (Contact From Object – Vegetation).
[37] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).
[38] The specific sub-drivers impacted include D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).
[39] According to Safety Data Sheets, Petroleum Electrical Insulating Oil (or transformer mineral-oil) has a Cleveland Open-Cup (COC) flashpoint rating of 145°C. Envirotemp FR3 Fluid has a COC flashpoint rating of 310°C.

Also, distribution transformers that are filled with ester fluid can operate at higher temperatures than mineral oil-filled distribution transformers, and still have the same life as the mineral oil-filled transformer. This increases the transformer kVA capacity. This added kVA capacity will prolong the life of the transformer's internal insulation system and improve summer heat storm performance.

As of April 2, 2018, all standard pole-type transformers supplied to SCE are now filled with ester fluid. Ester fluid-filled transformers are currently being installed to support new construction as well as transformer replacements driven by normal work processes (e.g., identified as deteriorated, overloaded, cutover to a higher voltage, etc.). These installations are not occurring on a proactive basis based on oil content alone. The full benefits and reduced risk of fire ignition by distribution transformers across the SCE system is expected to increase over time as the percentage of FR3-filled transformers rises across the system, including in HFRA areas.

1. Drivers Impacted

The use of FR3 transformers (C2) impacts sub-driver D2g (Equipment/Facility Failure – Transformer), as the new transformer fluid, with the higher flash point, will reduce the chance that a catastrophic failure will cause a fire ignition.

2. Outcomes & Consequences Impacted

Using FR3 transformers (C2) will not directly impact outcomes or consequences in the risk model.

D. Additional Controls Discussed in other chapters

In Chapter 12 (Climate Change), SCE models a control that likely also provides certain benefits to this Wildfire chapter. This is C2 – Fire Management Program. Table III-2 describes the interaction of Fire Management Program benefits between the two chapters.

Table III-2 – Control Included in Chapter 12 (Climate Change) with Providing Wildfire Benefit

Chapter 12 - Climate Change Chapter Control	Control Description	Likely Benefits for Wildfire Chapter
C2 – Fire Management Program	SCE maintains a Fire Management Team that includes fire management officers having experience as fire fighters and/or linemen. These fire management officers perform these activities: • Conduct training on electrical safety for first responders. • Proactively monitor fire threats to SCE infrastructure, coordinate with SCE Fire IMTs, and assist in restoration activities involving electrical assets. • Coordinate planning and response operations with external agencies and first responders. • Monitor climate change impacts on hazardous fuel (grass, heavy brush, chaparral, etc.) build-up that increase the severity and duration of wildfire events. Support project teams focus on hardening the grid to accommodate climate change drivers.	These efforts can reduce reliability impacts and increase the safety of our crews, first responders, and customers. For additional detail, please refer to Chapter 12 (Climate Change).

IV. Mitigations

Besides the controls detailed in Section III, SCE has identified potential new and innovative ways to mitigate this risk. These mitigations are summarized in Table IV-1, and discussed in more detail thereafter.

Table IV-1 – Inventory of Mitigations[40]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted
M1	Wildfire Covered Conductor Program	D1a, D1b, D1c, D1d, D2b, D2f	-	-
M1a	Wildfire Covered Conductor Program (including covered and bare sections)	D1a, D1b, D1c, D1d, D2b, D2f	-	-
M1b	Underground Conversion	D1 - All, D2 - All, D3, D4	-	-
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	-	O1, O2	All
M3	PSPS Protocol and Support Functions	-	O1	All
M4	Infrared Inspection Program	D2f	-	-
M5	Expanded Vegetation Management	D1d	-	-
M6	Microgrids	-	All	R
M7	Enhanced Situational Awareness	-	All	All
M8	Fusing Mitigation	D2b, D2d, D2e, D2f	-	-
M9	Fire Resistant Poles (M1 Scope)	-	All	All
M9a	Fire Resistant Poles (M1a Scope)	-	All	All
M9b	Fire Resistant Poles (M1b Scope)	-	All	All

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled in this report, and are addressed in Section IV.

A. M1 and M1a[41] – Wildfire Covered Conductor Program

Installing covered conductor on SCE's system is an enhanced mitigation technique for reducing wildfire ignition risks, as compared to bare conductor. Prior to 2015, there were

[40] Please refer to WP Ch. 10, pp. 10.9-10.26 (*RAMP Mitigation Reduction*) and WP Ch. 10, pp. 10.27-10.42 (*Mitigation Effectiveness Workpaper*).

[41] For RAMP modeling purposes, M1 captures the benefits of the covered conductor under WCCP, while M1a utilizes bare conductor for portions of circuits that meet SCD criteria and covered conductor for portions of circuits that meeting CFO criteria.

limited installations of older vintage covered conductor on SCE's system.[42] These limited installations typically occurred in heavily wooded areas with a history of outages (often related to animals and vegetation) and with limited access for tree pruning.

The covered conductor SCE is proposing to deploy as part of this mitigation utilizes a robust three-layer design. The design can prevent arcing caused by contact with a tree limb, conductor-to-conductor contact, or contact with a metallic balloon. In addition, the covering on the conductor (the "insulation") helps reduce the frequency of contact-related circuit interruptions that can lead to wire-down events. The insulation can also reduce the potential for electrocution in a wire-down event where the conductor remains energized. Finally, covered conductor will be sized to accommodate expected levels of fault current should faults occur, regardless of cause. This will also reduce the likelihood of wire-down events.

SCE's Wildfire Covered Conductor Program (WCCP) includes: (a) deploying covered conductor along with fire-resistant poles[43] when needed to meet loading requirements, and (b) replacing tree attachments with attachments to utility poles.[44] The WCCP is related to, but distinct from, the current OCP. Both programs address some of the same root causes of wire-down events. But OCP addresses safety and reliability at a more general level, while WCCP specifically focuses on enhancing system safety and resiliency in light of wildfire risks.

While both programs will have some related benefits,[45] the programs necessarily differ in priorities and work practices. WCCP seeks to prevent faults that can cause ignitions in HFRA and prioritizes circuits with higher wildfire risk. OCP, on the other hand, aims to prevent wire-down events that create public safety hazards, and focuses on circuits with higher short circuit duty (SCD) values that serve more customers, typically in urban areas.

As part of our WCCP efforts, SCE developed a circuit prioritization methodology to guide the order in which circuits would be hardened with covered conductor.[46] This approach lets SCE

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[42] See A.18-09-002, Prepared Testimony in Support of Southern California Edison Company's Application for Approval of Its Grid Safety and Resiliency Program (Section IV.B.1) for additional details regarding SCE's Wildfire Covered Conductor Program, historical use of covered conductor, and current proposed covered conductor.

[43] WCCP includes deploying covered conductor, installing fire-resistant poles, and remediating tree attachments. For RAMP modeling purposes, fire-resistant poles were modeled as a standalone mitigation.

[44] Older construction in the forested areas of SCE's service area sometimes made use of existing trees to carry conductor rather than a separate utility pole. These are called "tree attachments."

[45] WCCP will have some safety and reliability benefits and OCP will have some wildfire benefits.

[46] Please refer to WP Ch. 10, pp. 10.43-10.46 (*Circuit Deployment Prioritization*)

maximize the risk reduction benefits over time and prioritize those circuits with greater wildfire risk; this includes ignition frequency, ignition consequence, and estimated mitigation effectiveness when covered conductor is installed.

SCE has approximately 4,500 distribution circuits in its service territory. About 1,300 of these circuits traverse HFRA. WCCP will focus on certain spans located in HFRA that pose the greatest risk of fire ignition on these approximately 1,300 circuits. SCE has identified approximately 4,000 circuit miles of bare overhead conductor in HFRA that appear to be best suited for reconductoring with covered conductor[47] to mitigate contact-related faults and alleviate the risk of wire-down events during fault conditions.

These circuit miles encompass three main fire ignition risk areas within HFRA: (1) spans with vintage small conductor at risk of damage during fault conditions; (2) spans with elevated risks of faults caused by contact from object (vegetation-related); and (3) spans with elevated risks of non-vegetation-related contact from object faults.

While M1 involves reconductoring *solely with covered conductor*, M1a is a hybrid mitigation. In M1a, portions of distribution circuits that meet SCD criteria (vintage small conductor as described in item 1 above) will be reconductored *with bare conductor.* Other portions of circuits that meet the CFO criteria (as described in items 2 and 3 above) will be reconductored *with covered conductor*.

Likewise, M1b – discussed in the section below – also involves a hybrid approach. But here, the combination is different. M1b consists of a combination *covered conductor and underground conversion*.

Table IV-2 summarizes the differences in technology used within each of the M1, M1a and M1b mitigations.

Table IV-2 – Mitigation Scope for M1 Options

Mitigation	Short Circuit Duty Scope (945 circuit miles)	Contact From Object Scope (1,481 circuit miles)
M1	Covered Conductor	Covered Conductor
M1a	Bare Conductor	Covered Conductor
M1b	Covered Conductor	Undergrounding

[47] SCE plans to complete deploying covered conductor for approximately 4,000 circuit miles by 2025.

Currently, SCE removes conductor and equipment attached to trees when these items are identified during vegetation clearing or in response to a trouble call. Conductor installed on a tree is vulnerable due to its close contact with the tree and the risk that the tree will die. A dead tree can fall, and is more susceptible to burning. SCE has approximately 1,640 tree attachments currently in service in HFRA as part of its primary overhead distribution system. For both (M1) and (M1a), SCE will replace tree attachments together with deploying covered conductor; the work may include installing new poles.

1. Drivers Impacted

The WCCP (both M1 and M1a) impacts the same drivers addressed by the OCP, namely: D1 – Contact from Object, and D2 – Equipment / Facility Failure.[48]

M1 is modeled with a higher impact on Driver D1 (Contact from Object) than M1a. With M1, we would install more covered conductor, which should reduce the frequency of contact-related faults.

2. Outcomes & Consequences Impacted

The WCCP will not directly impact outcomes or consequences in the risk model.

B. M1b – Underground Conversion

As shown in the Table IV-2 above, M1b modifies M1 by utilizing underground conversion instead of covered conductor for portions of circuits that meet the CFO criteria; portions of circuits that meet the SCD criteria would still be reconductored with covered conductor.

To date, SCE has not performed any overhead to underground conversions to mitigate wildfire risk. SCE currently converts overhead lines to underground in compliance with Tariff Rules 20A, 20B, and 20C.[49] In cities where undergrounding is required, SCE will install all-new construction that complies with the city's requirements. This would be a new mitigation activity for SCE, because currently there are no programs which specifically target converting overhead to underground lines to address wildfire risks.

An overhead to underground conversion involves removing all above-ground equipment, such as poles, conductor, transformers, switches, etc. We then replace the above-ground equipment by installing underground conduit, cable, vaults, manholes, transformers, switches,

[48] Specifically, M1 and M1a affects the following sub-drivers: D1a (Contact from Object – Animal), D1b (Contact from Object – Balloons), D1d (Contact from Object – Vegetation), D2b (Equipment/Facility Failure – Conductor), and D2f (Equipment/Facility Failure – Splice/Clamp/Connector).
[49] See https://www.sce.com/NR/sc3/tm2/pdf/Rule20.pdf.

etc. This mitigation would target circuits, or sections of circuits, where the risk of damage would outweigh the relatively high cost of conversion.

Undergrounding electric facilities can be technically challenging and may require multiple designs based on specific geographic factors. For example, portions of SCE's San Joaquin district are heavily-forested and sparsely populated. These areas have overhead circuits installed away from roadways, and traversing hills and other challenging terrain. This makes access by SCE personnel difficult and time-consuming. In some instances, this type of circuit construction uses trees to carry conductor. As we eliminate circuits with tree attachments, we will rebuild along the road to foster our ability to restore service in snowy conditions. When conditions prevent us from safely placing overhead lines (such as no road shoulder, or sloping or rocky terrain), we would underground in the road.

1. Drivers Impacted

This mitigation impacts all drivers and sub-drivers in the risk model. Since this mitigation would eliminate portions the overhead system, all drivers would be impacted by the undergrounding mitigation.

2. Outcomes & Consequences Impacted

This mitigation will not directly impact outcomes or consequences in the risk model.

C. M2 – Remote-Controlled Automatic Reclosers (RARs) and Fast Curve Settings

M2 will perform two related efforts within HFRA: (1) installing 98 additional RARs with Fast Curve operating setting[50] in HFRA; and (2) updating the relay and/or settings on approximately 930 existing RARs and 1,164 circuit breakers with Fast Curve operating settings.

RARs are protective devices applied to mainline conductor that can automatically interrupt faults. The RARs will provide faster or more selective "fault clearing" to further reduce fire ignition risks and lessen service interruptions for SCE customers. These new RARs will provide fault interrupting capabilities with recloser blocking[51] and Fast Curve settings during Red Flag

[50] Fast Curve Setting modifies the relay fault detection curve, providing faster fault detection and interruption. Once the updated settings are installed, the Fast Curve can be remotely activated or de-activated through SCE's monitoring and control radio network.

[51] Under normal circumstances, SCE automatically recloses its circuits after they are de-energized from a fault interruption. Automatic reclosing is used to allow electric service to be restored quickly following a fault which is momentary or temporary. During Red Flag Warning conditions, SCE's Distribution Control Center remotely blocks the automatic reclosing relay for CBs and RARs within its HFRA. For these circuits, the reclosing relay is disabled and, following a fault, the circuit remains de-energized until a

Warnings. Additionally, they will provide isolation points to help implement Public Safety Power Shutoffs (PSPS). In particular, SCE's PSPS protocols will benefit from additional RARs, because less customers will be impacted if SCE can de-energize a relatively smaller portion of a circuit.

Additionally, during Red Flag Warning conditions, Fast Curve settings will be remotely enabled by SCE's Distribution Control Center operators, resulting in typical faults being cleared more quickly. Fast Curve settings reduce fault energy by increasing the speed with which a relay reacts to most fault currents.[52] Compared to conventional settings, reduced fault durations anticipated with Fast Curve operating settings are expected to reduce heating, arcing, and sparking for many faults.

1. Drivers Impacted

This mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition outcomes (O1 and O2). Given the RAMP model structure, SCE represented this mitigation as not impacting any drivers. See the Outcomes and Consequences section below for additional details.

2. Outcomes & Consequences Impacted

As previously stated, this mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition wildfire outcomes (O1 and O2). For modeling purposes, SCE represented this mitigation as impacting all consequences associated with O1 and O2.

Additionally, SCE notes that reducing wildfire risk by implementing more sensitive protective settings and the blocking of reclosing, will increase reliability consequences associated with faults that do not ignite wildfires. Since non-wildfire related faults are out of scope, the negative reliability impact of M2 is not reflected in the results of this risk analysis.

D. M3 – Public Safety Power Shutoff (PSPS) Protocol and Support Functions

SCE has recently instituted a formalized Public Safety Power Shutoff (PSPS) protocol where it may de-energize selected distribution circuits in HFRA[53] to reduce the chances of fire ignitions during the most extreme and potentially dangerous fire conditions. A PSPS event represents the

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patrol can inspect for sources of the fault. After the patrol inspection occurs, the circuit may then be re-energized and electric service restored.

[52] The Fast Curve reduction in fault energy is dependent on the fault magnitude and existing settings; as a general estimate, the configuration is expected to reduce fault energy by 50 percent.

[53] In rare circumstances, extreme fire conditions could dictate that SCE may need to de-energize a circuit outside the HFRA.

mitigation of last resort in a line of defenses against fire risk. This practice is aimed at keeping the public, SCE customers, and SCE workers safe. SCE currently considers many factors before de-energizing, including:

- Input from in-house meteorologists about current and forecast fire weather conditions;
- Wildfire fuel characteristics, and moisture levels of vegetation surrounding utility infrastructure; and
- Input from first responders and emergency management personnel regarding the potential impacts to ongoing evacuations, essential facilities/services, and at-risk customers.

In addition, SCE will deploy line patrol crews to assess circuit conditions before de-energizing. Prior to restoring service, we will also use these crews to confirm that it is safe to re-energize.

Public outreach is an important component of a utility's pre-emptive power shutoff protocol. SCE will complete outreach efforts with a number of stakeholders, including: state agencies, tribal governments, local agencies, and representatives from local communities. We will do so to help ensure these stakeholders are informed of the protocol and to solicit their feedback. This outreach will primarily be completed by October 2018, but will continue as needed to keep key stakeholders informed of the program. SCE continues to conduct community meetings and workshops to increase stakeholders' awareness and understanding of SCE's PSPS protocol, as well as to obtain feedback.

Additionally, SCE has procured a software solution to enhance its customer notification capabilities in order to more quickly and efficiently deliver notifications to customers before, during and following PSPS events. Specialized capabilities of this solution include:

- Ability to more quickly create and deliver customized outage communications in the customers' digital channel(s) of preference (Smartphone, SMS text, Email, and TTY);
- Bandwidth to deliver up to 1.5 million digital outage communications within one hour; and
- Ability to provide near real-time notifications and access historical records on notifications sent to customers.

To lessen the outage impacts to customers during PSPS events, on a case-by-case basis SCE will consider deploying available temporary mobile generators for Essential Use[54] customers to help maintain electric service for essential life, safety, and public services. Additionally, SCE plans to procure and deploy eight portable community power trailers to augment SCE's current customer outreach efforts during these events. Deploying the trailers will be prioritized based on factors like customer density and outage impact. These trailers can withstand high wind speeds associated with extreme fire conditions. The trailers can also provide local communities with charging stations for their phones, laptops, tablets, and other personal devices they rely upon to receive updates about the outage, monitor public safety broadcasts, and stay in contact with family and friends.

1. Drivers Impacted

This mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition wildfire outcomes (O1 and O2).[55] For modeling, SCE represented this mitigation as not impacting any drivers. See the Outcomes and Consequences section below for additional details.

2. Outcomes & Consequences Impacted

As previously stated, this mitigation is expected to reduce the frequency of only those drivers that lead to Red Flag condition wildfire outcomes (O1 and O2). For modeling, SCE represented this mitigation as impacting all consequences associated with O1.

Additionally, SCE notes that reducing wildfire risk by implementing PSPS will increase reliability consequences associated with those circuit interruption events where a wildfire ignition is not avoided. Since non-wildfire related faults are out of scope, the negative reliability impact of M3 is not reflected in the results of this risk analysis.

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[54] Essential Use customers are defined by the Commission as those that provide essential public health, and safety services. *See* General Order 166. Examples include agencies providing essential fire or police services, hospitals and skilled nursing facilities, communications utilities, facilities supporting fuel and transportation services, and water and sewage treatment utilities.

[55] As previously mentioned, forecast fire weather conditions is a key component in the decision process of executing a PSPS event. Additionally, there may be rare instances where SCE will need to de-energize through PSPS without the presence of a Red Flag Warning event.

E. M4 – Infrared (IR) Inspection Program

1. Description

SCE is developing a biennial Infrared (IR) Inspection Program for overhead distribution lines within HFRA. Inspection findings will be prioritized per SCE's Distribution Inspection Maintenance Program (DIMP) manual and given appropriate system remediation timeframes. The IR program will identify "Hot Spots" on distribution system equipment. Examples of equipment that will be included in the inspection program are splices, connectors, switches, and transformers. Hot Spots are areas where there is a temperature difference between either two phases, or two pieces of metal on one phase. These Hot Spots are not visible to the naked eye, and can only be detected by a trained thermographer using an IR camera. Hot Spots are reliable predictors of future component failures that, if unaddressed, could potentially result in fires and customer outages.

IR inspections will help increase safety by enhancing critical circuit inspections and reducing fire safety hazards caused by potential equipment failures. These IR inspections will also improve reliability.

2. Drivers Impacted

The IR Inspection Program (M4) impacts Driver D2 (Equipment / Facility Failure)[56] by detecting in advance certain types of equipment failure before it occurs.

3. Outcomes & Consequences Impacted

This mitigation will not directly impact outcomes or consequences in the risk model.

F. M5 – Expanded Vegetation Management

M5 expands SCE's vegetation management activities to assess the structural condition of trees in HFRA that are not dead or dying, but could fall into or otherwise impact electrical facilities. These trees may be as far as 200 feet away from SCE's electrical facilities. Trees posing a potential risk to electrical facilities due to their structural or site condition will be removed or otherwise mitigated.

For example, a 75-foot tall palm tree located 50 feet from electrical facilities not only has the potential to fall into these facilities, but its palm fronds can dislodge and blow into electrical facilities, igniting a fire. While this palm tree meets all mandated compliance clearances and is not dead or dying, SCE may still identify it as a potential risk to be mitigated by either removing

[56] Specifically, M4 affects Sub-Driver D2f (Equipment/Facility Failure – Splice/Clamp/Connector).

dead fronds or removing the tree altogether. SCE views this as an important effort in light of increasing winds that have the potential to blow palm fronds and other debris into utility lines from even greater distances.

1. Drivers Impacted

The Expanded Vegetation Management program impacts D1d (Contact From Object – Vegetation) by reducing the frequency of vegetation contact-related faults.

2. Outcomes & Consequences Impacted

The Expanded Vegetation Management program (M5) will not impact outcomes or consequences in the risk model.

G. M6 – Microgrids

A microgrid is a collection of generation sources (including conventional and renewable generators, demand side management, and energy storage) and loads capable of operating in parallel with, or independently of, the main power grid. In remote areas, especially those in rural or forested areas, electricity may need to pass over utility equipment located in HFRA. Microgrids could provide greater resiliency to critical customers, water pumping, and hospitals in these areas during times when grid power may need to be proactively shut off to minimize the potential for wildfire ignition during inclement weather conditions. Microgrids are not intended as a permanent service solution, but rather can serve as a backup power source to provide service continuity during critical periods.

1. Drivers Impacted

This mitigation provides resiliency during a PSPS event and will not mitigate any of the drivers. Therefore, Microgrids (M6) will not impact driver frequencies in the risk model.

2. Outcomes & Consequences Impacted

This mitigation will impact the reliability consequences associated with all outcomes, because it provides for faster temporary restoration of power to customers during interruption events.

H. M7 – Enhanced Situational Awareness

M7 will enhance our wildfire situational awareness by deploying weather stations and High Definition (HD) cameras across our HFRA, a high-resolution weather model, and a high-performing computing platform for fire potential index modeling. Situational awareness is an integral part of emergency management, because SCE needs a granular understanding of what is happening across its service area prior to and during emergency events. SCE is further

enhancing its situational awareness capabilities to address increasing fire risks throughout its service area. SCE is focused on accessing more detailed information about wildfire risk at the individual circuit level, to better understand how weather conditions might impact utility infrastructure and public safety in high fire risk areas.

SCE intends to enhance its existing weather models by installing additional weather stations on circuits within HFRA. These additional weather stations will enhance the resolution of existing weather models and provide real-time information to help make key operational decisions during potential fire conditions, including PSPS deployment.

When installed, weather stations use various sensors and communications to provide meteorologists with real-time weather data. This includes temperature, relative humidity, dew point, wind speed, wind direction, wind gust behavior, wind gust direction, and other variables.

The weather stations' capabilities include a datalogger, a central component of the station which measures signals coming from the weather station sensors.

Through October 2018, SCE has installed over 110 new stations. SCE's fire meteorologists will continue identifying potential locations for up to approximately 850 total weather stations by 2020.

SCE is installing pan-tilt-zoom (PTZ) HD cameras throughout its HFRA to enable fire agencies and SCE personnel to more quickly identify and evaluate emerging wildfires. Deploying HD cameras throughout our HFRA will enhance SCE's situational awareness capabilities and enable emergency management personnel, including fire agencies, to more swiftly respond to emerging wildfires. In particular, HD camera images save time in verifying and assessing a fire's severity as compared to sending fire crews to perform this assessment.

HD camera views will transmit into SCE's Situational Awareness Center, and will be used by our Incident Management Teams (IMT) to decide how to deploy crews and make other operational decisions, such as PSPS activation. These HD cameras will help mitigate potential safety risks to the public and prevent damage to electric infrastructure. Between 2018 and 2020, SCE is planning to install up to 160 PTZ HD cameras on approximately 80 towers. This will provide coverage of nearly 90 percent of SCE's HFRA.

SCE has contracted with IBM to access a high-resolution weather model. The model will forecast weather parameters such as temperature, wind speed and gusts, humidity, precipitation and fuel characteristics. It will provide these benefits:

- Enhanced resolution and more accurate forecast data to better inform deploying SCE's PSPS protocol;
- Severe-weather forecasting including wind, thunderstorms, heavy rain events and extreme temperatures;
- Visualization of weather conditions and forecasts around SCE infrastructure; and
- Overall support to SCE's IMT in developing HFRA forecasts and fire response plans.

SCE intends to deploy a high-performance computing platform to improve its ability to scientifically quantify the risk of wildfire ignitions in different geographic regions throughout its service area. SCE will procure advanced computer hardware and deploy state-of-the-art software that will run a sophisticated Fire Potential Index model. The model will account for various factors including weather, live fuel moisture, and dead fuel moisture to assess the level of risk of wildfire ignitions.

Our efforts here will also enable software to analyze decades of data for fuel and weather characteristics from past wildfire ignitions, and compare and contrast those variables against current conditions to forecast the Fire Potential Index. The output from this model will inform operational decisions, implement work restrictions, and optimize resource allocation for emergency situations.

SCE will implement an Asset Reliability and Risk Analytics program to build capabilities in predicting an asset's overall wildfire-related risk and prioritize work, repairs, and/or replacement(s) to minimize potential wildfire ignitions.

Additionally, the state's substantially increasing fire risk means that SCE must respond to more frequent and prolonged fire threats throughout its service area. SCE will augment its Business Resiliency staff with four full-time positions to accommodate the increased demands.

1. Drivers Impacted

This mitigation focuses on improving situational awareness and therefore will not directly impact any of the drivers in the risk model.

2. Outcomes & Consequences Impacted

As this mitigation will improve situational awareness related to wildfires in the SCE system, M7 will impact all consequences related to wildfire outcomes in the risk model.

I. M8 – Fusing Mitigation

M8 plans to install or replace fuses at approximately 15,613 fuse locations in two main groupings. The 15,613 figure represents the number of branch line locations in the HFRA. This mitigation should ensure that all locations are addressed. First, we will install new Current Limiting Fuses (CLFs) at 8,855 branch line locations. Second, we will replace existing fuses with CLFs at up to 6,758 existing fuse locations on circuits that traverse the HFRA. This program should reduce the risk of fire ignitions associated with SCE's distribution lines and equipment by reducing fault energy. We plan to complete this work during the 2018-2020 timeframe.

SCE has traditionally applied fuses on branch line locations to improve electric service reliability by limiting the number of customers affected by a fault. This practice has resulted in fuse application on approximately 43 percent of the HFRA-related branch circuits. This mitigation will result in fuse application of approximately 100% of HFRA-related branch circuits when complete. SCE has traditionally used conventional expulsion type fuses (conventional fuses) for fuse applications. For this M8, SCE intends to utilize CLFs instead of conventional fuses for most applications in the HFRA. We selected CLFs for this application because they provide faster fault clearing for most faults and reduce fault energy, compared to a conventional fuse.

Table IV-3 illustrates the groups of fuse installations and replacements.

Table IV-3 – Fuse Groups

Group	Sub-group	Fuse Locations
Installing new CLFs	N/A	8,885
Replacing existing fuses	Conventional expulsion type	1,656
	Conventional non-expulsion type	5,102
Total		**15,613**

For the first group (installing new CLFs), M8 will install new fuses on distribution circuit branch lines in HFRA which are not presently fused, or that may benefit from further segmentation via additional fuse installations. The program will also replace certain existing conventional fuses with CLFs to further minimize ignition risk.

The second group (replacing existing conventional fuses) can be divided into two sub-groups. The first sub-group involves replacing existing expulsion type fuses which require brush clearing at the base of the pole to remove potentially flammable vegetation.[57] The second sub-

[57] This aligns with the CalFire Power Line Fire Prevention Field Guide.

group involves replacing existing conventional non-expulsion type fuses that would benefit from the current limiting technology for energy reduction, but would otherwise be exempt from brush clearing per CalFire's Power Line Fire Prevention Field Guide.

1. Drivers Impacted

SCE's Fusing Mitigation Program impacts Driver D2 - Equipment/Facility Failure.[58] It does so by de-energizing branch lines that experience faults and reducing the fault energy that can damage conductors, insulators, or connectors.

2. Outcomes & Consequences Impacted

The Fusing Mitigation (M8) will not directly impact outcomes or consequences in the risk model.

J. M9, M9a, M9b[59] – Fire-Resistant Poles

At locations where SCE is installing covered conductor in HFRA and pole replacements are required, SCE will use fire-resistant composite poles, where appropriate, instead of traditional wood poles. The variation in mitigation scenarios for M9 (M9, M9a, and M9b) reflect different volumes of installing fire-resistant poles. The volumes of these installations are commensurate with the volumes of covered conductor deployment in M1, M1a, and M1b, respectively. Table IV-4 illustrates this relationship and the number of pole installations contemplated for this mitigation.

Table IV-4 – Covered Conductor & Fire-Resistant Pole Deployment Scenarios

Wildfire Conductor Mitigation Variant	Conductor Type and Volume (circuit miles)	# of Fire-Resistant Poles Modeled in M9 Variant
M1 *(All Covered)*	Covered Conductor - 2,426	27,513
M1a *(Bare + Covered)*	Covered Conductor - 1,481 Bare Conductor - 945	23,940
M1b *(Covered + Underground)*	Covered Conductor – 945	11,060

[58] Specifically, M8 impacts the following sub-drivers: D2b (Equipment/Facility Failure – Conductor), D2d (Equipment/Facility Failure – Fuse), D2e (Equipment/Facility Failure – Insulator), and D2f (Equipment/Facility Failure – Splice/Connector/Clamp).
[59] For RAMP modeling purposes, M9a corresponds to the number of poles requiring replacement that are associated with M1a bare conductor alternative, while M9b corresponds to the number of poles requiring replacement with the M1b undergrounding alternative.

These poles are specifically designed to withstand wildfires; use of the poles will harden the distribution system. This increases the chances that SCE equipment, including conductor, will remain in the air should a wildfire occur, which will afford multiple benefits. First, the equipment is less likely to be damaged if it is out of the path of the fire. Second, with less damage, SCE can re-energize more quickly after a wildfire event. Finally, if the utility equipment remains intact, then members of the public and first responders are safer.

SCE has experience with similar composite poles. Compared to steel poles, composite poles are non-conductive and resistant to corrosion. And compared to wood poles, composite poles are less susceptible to wildlife damage (e.g., woodpeckers), rotting, and fires, and are also lighter in weight and can carry more load (when compared to wood poles of the same class and size). In general, composite poles are preferred to wood poles in several contexts, such as restricted vehicle access (for sectional composite poles) and areas of accelerated pole degradation.

The composite poles SCE plans to install are manufactured using polyurethane resin and E-glass fiber to create a fiber-reinforced polymer (FRP) laminate. Manufacturer testing has proven that the laminate is self-extinguishing (i.e., fire-resistant). In addition, a shield manufactured from the same fire-resistant material is wrapped around the composite pole sections at the manufacturing plant. When the pole is installed, the shield is embedded 12 inches below the ground line of the final grade. Manufacturer testing has shown[60] that the shield will increase fire resistance, enabling the pole to withstand an "extreme" wildfire.[61]

1. Drivers Impacted

This mitigation is focused on provide resiliency during a wildfire event and therefore will not reduce any driver frequencies in the risk model.

2. Outcomes & Consequences Impacted

As this mitigation will improve grid resiliency related to wildfires in the SCE system, M9 will impact all outcomes and consequences in the risk model.

[60] RS Technical Bulletin: 17-010, *RS Poles and Fire Shields Fire Performance*, at p. 1 (February 1, 2018), *available at* https://www.rspoles.com/sites/default/files/resources/C801---17-010---RS-Poles-and-Shields-Fire-Performance-01-Feb-18.pdf.

[61] *Id.* at p. 13. "Extreme" wildfire exposure is defined as gas temperatures between 800 to 1,200°C and exposure of 121 to 180 seconds. *Id.* at p. 4.

V. Proposed Plan

SCE has evaluated each control and mitigation listed in Sections III and IV and has developed a Proposed Plan of controls and mitigations to pursue, as shown in Table V-1 below. Before discussing these controls and mitigations in detail, certain aspects of the analysis should be placed in context. Examining the relative RSE values shows that, in certain cases, the RSE does not accurately capture certain "real life" factors that are critical in actually choosing mitigations.

First, as SCE discussed in Chapter 1 (RAMP Overview), restricting the evaluation of risk reduction and risk spend efficiency to the 2018-2023 RAMP period can distort the benefits of those mitigations whose benefits will extend significantly beyond 2023. Long-lived assets that are installed during the RAMP period continue to operate and provide risk reduction benefits for many years thereafter. There can be dissonance in RSE comparisons between this type of mitigation compared to an O&M mitigation that has more short-lived benefits. In these cases, the long-lived mitigation will have an RSE that is understated compared to the short-term O&M mitigation.

This dissonance can be seen, for example, when assessing mitigation M1 (Wildfire Covered Conductor Program). The long-term benefits are simply not fully captured in the RSE calculation. To illustrate this, SCE has prepared a long-term pilot analysis. The analysis is found at Appendix 1 to this chapter. In that Appendix, the RAMP analysis is extended out to 50 years rather than the 6-year RAMP period, to estimate the full benefit that the covered conductor assets provide over their useful life. When this longer-term pilot analysis is performed, we see the following results:

- Compared to the 6-year RAMP analysis, the long-term RSE of covered conductor on a mean basis increases 18 times.
- Compared to the 6-year RAMP analysis, the long-term RSE of covered conductor on a tail average basis increases 18 times.[62]

Thus, the RSE comparison is somewhat "skewed" between the longer-lived Wildfire Covered Conductor Program (M1) and the O&M mitigation activities such as PSPS Protocol and Support Functions (M3) and Infrared Inspection Program (M4). The risk reduction benefits of M1 are understated compared to the risk reduction benefits of M3 and M4.

[62] The mean and tail average results have not had any discounting applied.

Also, the RSE necessarily cannot take into account certain operational realities. If one looks solely at the RSE scores, there might be a question as to why SCE doesn't forego the Covered Conductor Plan to a significant degree in favor of the PSPS Protocol and the Infrared Inspection Program. But the respective programs address different aspects of mitigating wildfire risk. In today's increasing wildfire risk environment, a sound wildfire mitigation plan must address conductors. The PSPS Protocol and Infrared Inspection Program do not directly address conductors and conductor performance. Making mitigation decisions in this case purely on RSE would lead to significant parts of the system and potentially significant risk issues being unaddressed.

Moreover, there are also real-life "scalability" issues that the RSE comparison cannot take into account. There are practical limits in how much PSPS and infrared inspections can be deployed. One is a system shut-off protocol; it is a mitigation of last resort. The other is an inspection program that does not, and cannot, actually strengthen system components against wildfires.

Table V-1 – Proposed Plan (2018 – 2013 Totals)[63]

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Overhead Conductor Program (Bare + Covered)	2018	2023	$ 102	$ -	0.12	0.0012	0.39	0.0038
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.05	0.0007	0.17	0.0021
M1	Wildfire Covered Conductor Program	2018	2023	$ 1,161	$ -	2.27	0.0020*	7.22	0.0062*
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0310	3.29	0.1057
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.90	0.0889	6.55	0.3068
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1017	0.93	0.3243
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.38	0.0010	1.20	0.0033
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.84	0.0148	3.14	0.0552
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.73	0.0079
M9	Fire Resistant Poles (M1 Scope)	2018	2023	$ 137	$ -	0.60	0.0043	2.21	0.0161
			Total	**$1,609**	**$447**	**7.65**	**0.0037**	**25.83**	**0.0126**

*Full benefits are not included in 6-yr RSE for M1. If full benefits (without any discount) were included for M1 and it was modeled independently, its RSE would increase by 18 times on both a mean and tail-average basis. Please see Section IX-Appendix 1 to this Chapter, and discussion above, for additional details.

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

[63] With respect to M1 (Wildfire Conductor Program): Since Tree Attachments were not modeled, the costs associated with Tree Attachments are not included with the M1 – Wildfire Covered Conductor Program costs. Additional information on the modeling of Tree Attachments is found in Section VIII – Lessons Learned.

There are a few additional items to note when examining the Proposed Plan and the relative mitigation scores:

- *Wildfire Covered Conductor Program [M1]* – the risk benefits are understated to an additional degree because the *benefits* of this mitigation associated with Chapter 5 - (Contact with Energized Equipment) are *not* included in this chapter, but the *full cost* of this mitigation *is* included. The costs are not apportioned out between Wildfire and Contact with Energized Equipment. Each chapter calculates RSE using the full cost of the program.
- *PSPS Protocol and Support Functions [M3]* – the risk benefits are overstated because we do not capture the reliability consequences that occur when de-energizations do not prevent a fire.
- *Enhanced Situational Awareness [M7]* – the risk benefits are understated because they do not capture the positive effects of addressing and mitigating fires that are not associated with SCE.
- *Fire-Resistant Poles [M9]* – the risk benefits are understated because they do not capture the positive effects of addressing fires not associated with SCE.
- *RAMP and GS&RP* – For illustrative purposes, SCE has included a workpaper[64] demonstrating that SCE's GS&RP application and RAMP are aligned. The workpaper shows that comparable GS&RP and RAMP analyses produce similar results concerning the cost efficiency of bare conductor compared to covered conductor. Please also see the discussion found in section V.D below.

A. Overview

As we developed our Proposed Plan, we considered many factors, including:

- The risk assessment outlined in this chapter;
- How various controls and mitigations impact the drivers, triggering event, outcomes, and/or consequences;
- The potential execution speed and timing of mitigations;
- How various mitigations might complement one another or existing controls; and
- Cost.

[64] Please refer to WP Ch. 10, pp. 10.47-10.51 (*RAMP to GSRP Comparison Workpaper*).

In light of the "new normal" regarding the increasing wildfire risk in SCE's service area, the Proposed Plan represents a comprehensive approach to enhance SCE's existing wildfire mitigation efforts and target the principal drivers that lead to potential wildfire ignitions.

A primary component of SCE's Proposed Plan includes deploying covered conductor (M1). This mitigation targets Driver D1 (Contact from Object). That driver represents the majority of faults that can potentially lead to wildfire ignitions.

As described in Section IV.A (M1 - Wildfire Covered Conductor Program), this mitigation seeks to prevent faults from occurring, and targets three categories of overhead lines: (1) spans with vintage small conductor at greater risk of being damaged during fault conditions; (2) spans with elevated risks of faults due to vegetation-related contact from objects; and (3) spans with elevated risks faults due to non-vegetation-related contact from objects.

The first category, vintage small conductor, is addressed by both SCE's existing Overhead Conductor Program, and SCE's Wildfire Covered Conductor Program. The scope represented by C1 (Overhead Conductor Program Covered 2021-2023) consists of in-flight Overhead Conductor Program projects that will be executed with the bare wire standards in place prior to developing our Wildfire Covered Conductor Program. If we have conductor that meets the criteria for this category but is not included in C1, the mitigation will occur through M1 (Wildfire Covered Conductor Program).

The second category, vegetation-related faults, is addressed by SCE's Wildfire Covered Conductor Program (M1), Expanded Vegetation Management (M5) and Vegetation Management (CM1). Mitigation M5 is incremental to SCE's existing vegetation management practices (CM1), and will further mitigate tree-related ignitions, particularly in areas where covered conductor is not being deployed.

The third category, non-vegetation-related faults, is addressed primarily by our Wildfire Covered Conductor Program (M1). While the primary selection and targeting of the Wildfire Covered Conductor Program focused on mitigating wildfire outcomes and consequences, M1 is expected to provide meaningful improvements in reliability due to its inherent ability to prevent contact from object-related faults (D1).

Remote-Controlled Automatic Reclosers and Fast Curve Settings (M2) and Fusing Mitigation (M8) work with each other, and work in conjunction with our Wildfire Covered Conductor Program (M1), by reducing the energy associated with faults that may occur, regardless of the cause of the fault. These mitigations complement the Wildfire Covered Conductor Program by providing this energy-reducing protective capability for both covered and bare conductor,

either during the time period before covered conductor is scheduled to be installed, or for lines that are not targeted for covered conductor deployment. These mitigations provide ignition-related benefits for all types of faults, including those faults that cannot be mitigated by covered conductor.

Infrared inspections (M4) complement the above-mentioned mitigation measures by targeting additional sub-drivers to D2 (Equipment/Facility Failure drivers) that are not mitigated by covered conductor, such as D2a (Capacitor Banks) and D2g (Transformers).

Covered conductor (M1) and infrared inspections (M4) are expected to mitigate Sub-Driver D2f (Splice/Clamp/Connector). Infrared inspections are expected to mitigate these types of failures on lines when the installation of covered conductor is scheduled but has not yet occurred, or when there are lines that are not targeted to have covered conductor.

Using ester fluid FR3 transformers (C2) for both new and future replacements of overhead transformers works in conjunction with infrared inspections, by reducing both the frequency of transformer failures (slower aging of insulation) as well as reducing the potential consequence should a transformer fail (it is less likely that fluid has reached its flash point).

PSPS Protocol and Support Functions (M3) represents SCE's mitigation of last resort and would be exercised if extreme fire conditions develop and existing controls and other proposed mitigations are insufficient to address the emergent risk. Enhanced Situational Awareness (M7) (i.e., high-resolution forecasting coupled with weather stations) is expected to improve SCE's predicting capabilities. It should reduce false positives that result in pre-emptively deploying resources and notifying customers in advance of potential de-energization. We also expect improvement in targeting of PSPS; this should reduce the number of circuits that have to be de-energized. While SCE believes PSPS should be available in extreme circumstances, it is not a long-term solution that can be used in place of the other mitigations shown in the portfolio.

Lastly, Enhanced Situational Awareness (M7) and Fire-Resistant poles (M9) aim to mitigate consequences associated with ignitions that do occur. These mitigations can help reduce the size of wildfires through faster suppression response and faster restoration times should fires engulf SCE infrastructure.

B. Execution feasibility

While some of the mitigations listed in the Proposed Plan have not been previously executed by SCE to the proposed scale, SCE has obtained experience in execution and a greater understanding of cycle times by deploying in advance some portion of the mitigation portfolio. This includes starting to install covered conductor on the highest-priority circuits, and deploying

some weather stations and HD cameras in HFRA. The current mitigation deployment timeline evaluates mitigation deployment cycle time, risk reduction, and resources constraints to develop a plan to maximize risk reduction in light of these factors.

While the Proposed Plan represents significant work over the intended time period, it is operationally feasible to increase mitigation deployment capacities and complete this target in addition to its other ongoing and planned activities. In early 2018, SCE created a program management office (PMO) focused exclusively on bolstering public safety and grid resiliency. We created the PMO in part to consolidate SCE's grid-hardening projects to enable more streamlined and expeditious deployment. As part of this effort, SCE carefully considered how quickly it could move forward with its wildfire mitigation portfolio. SCE views the proposed timeline as both operationally feasible and prudent, given the importance and urgency of mitigating wildfire risks and hardening the grid.

C. Affordability

The Proposed Plan has the second-lowest cost of the three plans. The RSE of the Proposed Plan is just slightly lower than the RSE of the Alternative Plan #1, and significantly higher than the RSE of Alternative Plan #2. The Proposed Plan's RSE is less than Alternative #1 because the conductor-related mitigations in Alternative #1 cost less than the conductor-related mitigations in the Proposed Plan, and the RSE of each conductor-related mitigation is lower than the respective portfolio-level RSE.[65]

Using covered conductor is a crucial part of SCE's Proposed Plan. Each of the three plans includes a significant amount of conductor-related controls and mitigations. To understand the differences in underlying cost-effectiveness of the Proposed Plan compared to the alternative plans, it is helpful to examine the RSEs of the conductor-related controls and mitigations.

The conductor-related controls and mitigations are as follows:

- The Proposed Plan uses C1 and M1.
- Alternative Plan #1 uses C1a and M1a.
- Alternative Plan #2 uses C1 and M1b.

The Proposed Plan's conductor related controls and mitigations provide the most value of all conductor-related controls and mitigations in the three plans. The conductor-related

[65] Please see Section V.A for a discussion of underrepresentation of long-term benefits for covered conductor.

controls and mitigations in the Proposed Plan have a higher RSE than Alternative Plan #1 and Alternative Plan #2.

The Proposed Plan's conductor-related controls and mitigations have a much higher Mitigation Risk Reduction than those Alternative #1. While Alternative Plan #2 has the largest Mitigation Risk Reduction among the three plans for conductor-related controls and mitigations, it also has a much lower RSE than the Proposed Plan and Alternative Plan #1.

Table V-2 below shows a comparison of conductor options and associated risk reduction and risk spend efficiency.

Table V-2 – Comparison of Conductor-Related Mitigation Options

Figures represent 2018 – 2023 totals	Cost ($M)	Mitigation Risk Reduction (Mean)	Risk Spend Efficiency (Mean)	Miles Addressed[66]
C1 and M1 *(Proposed Plan)*	$1,263	2.39	1.892E-03	2,680 circuit miles: ***M1:*** *2,426 Covered* ***C1:*** *65 Covered + 189 Bare* *0 underground*
C1a and M1a *(Alternative Plan #1)*	$1,044	1.90	1.820E-03	2,680 circuit miles: ***M1a:*** *1,481 Covered + 945 Bare* ***C1a:*** *254 Bare* *0 underground*
C1 and M1b *(Alternative Plan #2)*	$5,501	2.99	0.365E-03	2,680 circuit miles ***M1b:*** *945 Covered+ 1,481 Underground* ***C1:*** *65 Covered + 189 Bare*

The Proposed Plan assumes deployment of our Overhead Conductor Program with bare conductor in years 2018-2020 and covered conductor in years 2021-2023 (C1), and the Wildfire Covered Conductor Program with covered conductor in years 2018-2023 (M1).

[66] SCE modeled three different conductor types (covered, bare, and underground) across the three portfolios. Different conductor types were selected in each portfolio based on the fault risk areas within HFRA. For example, Alternative Plan #1 evaluates bare conductor use in short circuit duty areas. Alternative Plan #2 evaluates use of Underground Cable for CFO areas.

This fundamentally differs from Alternative Plan #1, which assumes the existing Overhead Conductor Program with entirely bare conductor in years 2018-2023 and the Wildfire Covered Conductor Program with a mix of bare conductor and covered conductor in years 2018-2023.

This is also fundamentally different than Alternative Plan #2, which assumes existing Overhead Conductor Program bare conductor in years 2018-2020 and covered conductor in years 2021-2023, and the Wildfire Covered Conductor Program with a mix of covered conductor and underground conversion in years 2018-2023.

Therefore, the alternative plans reflect two theoretical "modifications" to the Proposed Plan. Alternative Plan #1 represents a "downgrade" of the Proposed Plan, with increased use of bare conductor. Alternative Plan #2 represents an "expansion" of the Proposed Plan, with increased use of underground conversion.

There are similarities in the RSEs of the Proposed Plan and Alternative Plan #1. The modeled scope in the Proposed Plan and Alternative Plan #1 are over 60% identical (each plan includes at least 189 miles of bare conductor and 1,481 miles of covered conductor). Moreover, the variation in scope is less than 40% between the two Plans. The greater RSE of conductor-based mitigations within the Proposed Plan relative to the Alternative Plan #1 would have been more pronounced had the two plans been modeled with a much larger variation in scope. We chose to model with similar scope to evaluate risk scoring while minimizing variability. This is illustrated by *the large variation* in RSE between the Proposed Plan and Alternative Plan #2, which has a significantly different scope (nearly 1,500 miles of underground conversion) and a much clearer difference in RSE (significantly lower RSE).

D. Other Considerations

The mitigation effectiveness discussions in this RAMP chapter differ in several ways from the mitigation effectiveness discussions found in SCE's GS&RP application. The basic mitigation effectiveness **inputs** used within GS&RP and RAMP are closely aligned. But those inputs are **analyzed** using different methodologies. For example, the GS&RP application compares implementations of different conductor mitigations (i.e., bare versus covered versus underground conversion) across the entire HFRA to develop a mitigation effectiveness factor.[67] The application then develops a mitigation-to-cost ratio for each conductor mitigation. It does not combine the different conductor mitigations.

[67] See page 52 of the GS&RP filing (A. 18-09-002).

In contrast, the RAMP analysis compares different combinations of conductor mitigations (e.g., M1, M1a, or M1b, paired with other mitigations) implemented across a portion of the HFRA. Our RAMP analysis then uses the MARS methodology to calculate a Mitigation Risk Reduction for each portfolio, and then calculates a Risk Spend Efficiency for each portfolio based on cost.[68]

Despite the differences in analytical approaches, the GS&RP and RAMP are aligned. For illustrative purposes, we have included a workpaper that provides an example of applying the GS&RP analysis parameters to RAMP modeling.[69] The workpaper takes the GS&RP analysis of bare conductor versus covered conductor, and runs an equivalent analysis using the RAMP model.[70] As shown in the workpaper, the comparable GS&RP and RAMP analyses produce similar results regarding the cost efficiency of bare conductor compared to covered conductor.

The Proposed Plan is informed by SCE's current capabilities for evaluating and prioritizing mitigation measures, SCE's capabilities to predict potential driver occurrences, and the availability of technologies that can be deployed and are effective at mitigating wildfire risk. In performing these mitigation measures over time, different factors may drive adjustments to the Proposed Plan. These factors include changes to the risk landscape that may be impacted by climate changes and/or mitigation measures implemented by third parties, and improvements in SCE's ability to evaluate wildfire risk across its service territory. Also, policy constraints may restrict SCE's ability to implement desired mitigations or may change how we allocate limited resources.

Lastly, as new technologies emerge, SCE will continue to evaluate the effectiveness of more advanced solutions and how they may complement its existing portfolio of mitigation measures. If new measures prove to be better than existing ones, SCE will work to transition to these improved measures as appropriate.

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[68] See Chapter 2 (Risk Model Overview) for additional detail regarding MARS, MRR and RSE.
[69] Please refer to WP Ch. 10, pp. 10.47-10.51 (*RAMP to GSRP Comparison Workpaper*).
[70] In running the equivalent analysis, SCE used the same potential frequency of ignition and scope assumptions under which the GS&RP analysis was performed.

VI. Alternative Plan #1

SCE evaluated other options to address this risk and developed an alternative plan as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018 – 2013 Totals)[71]

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1a	Overhead Conductor Program - (Bare Only)	2018	2023	$ 98	$ -	0.08	0.0008	0.24	0.0025
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.06	0.0007	0.18	0.0022
M1a	Wildfire Covered Conductor Program (including covered and bare sections)	2018	2023	$ 947	$ -	1.83	0.0019	5.87	0.0062
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0311	3.34	0.1073
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.91	0.0893	6.64	0.3112
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.30	0.1031	0.95	0.3324
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.39	0.0010	1.24	0.0034
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0149	3.19	0.0562
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.74	0.0081
M9a	Fire Resistant Poles (M1a Scope)	2018	2023	$ 119	$ -	0.53	0.0044	1.99	0.0167
			Total	**$1,372**	**$447**	**7.12**	**0.0039**	**24.40**	**0.0134**

A. Overview

Alternative Plan #1 deploys many of the same controls and mitigations as the Proposed Plan. However, a key difference between these two plans is the conductor-related mitigations chosen. Alternative Plan #1 represents a scenario where SCE uses the less expensive, and less effective, bare reconductoring mitigation in place of covered conductor. Alternative Plan #1 (using C1a) deploys bare conductor to target vintage small conductor for work between 2021-2023. In contrast, the Proposed Plan (using C1) deploys covered conductor for that same period.

Alternative Plan #1 also includes M1a, which uses bare conductor for the portions of circuits designated as short circuit duty. In contrast, the Proposed Plan includes M1, which uses covered conductor for those same portions. As discussed in Section V (Proposed Plan) bare reconductoring is less effective than using covered conductor at addressing the wildfire risk.[72] This was a key factor in our decision not to select Alternative Plan #1.

[71] With respect to M1a: Since Tree Attachments are not modeled, the costs associated with Tree Attachments are not included with the M1a – Wildfire Covered Conductor Program (CFO – CC, SCE Lengths – Bare) costs.
[72] Please see Section V.C for additional detail.

Lastly, with respect to fire-resistant Poles, Alternative Plan #1 includes M9a as it corresponds to a reduced number of pole replacements associated with bare conductor. Bare conductor imparts lower gravity and wind loads on the poles as compared to covered conductor. In contrast, the Proposed Plan includes M9, to align with the type and volume of conductor deployed in that plan.

The remaining control (C2) and mitigations (M2 through M5, M7, and M8) remain identical to the Proposed Plan. This control and these mitigations are not impacted by the choice to use bare conductor for selected portions of circuits to be hardened.

B. Execution feasibility

The execution feasibility of Alternative Plan #1 is very similar to the Proposed Plan.

C. Affordability

Alternative Plan #1 represents the least expensive plan, but also provides the least amount of risk reduction. Bare reconductoring is much less effective than covered conductor in terms of avoiding wildfires. Additionally, the fact that bare reconductoring is unable to mitigate the majority of fault types that are associated with fire ignitions makes Alternative Plan #1 less desirable.

D. Other Considerations

The constraints associated with this alternative are similar to the Proposed Plan.

VII. Alternative Plan #2

SCE developed one other alternative plan, as shown in Table VII-1.

Table VII-1 – Alternative Plan #2 (2018 – 2013 Totals)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Overhead Conductor Program (Bare + Covered)	2018	2023	$ 102	$ -	0.12	0.0012	0.38	0.0037
C2	FR3 Overhead Distribution Transformer	2018	2023	$ 81	$ -	0.05	0.0007	0.17	0.0021
M1b	Underground Conversion	2018	2023	$ 5,399	$ -	2.87	0.0005	9.00	0.0017
M2	Remote-Controlled Automatic Reclosers and Fast Curve Settings	2018	2019	$ 28	$ 3	0.97	0.0312	3.26	0.1048
M3	PSPS Protocol and Support Functions	2018	2023	$ -	$ 21	1.91	0.0896	6.49	0.3040
M4	Infrared Inspection Program	2018	2023	$ -	$ 3	0.29	0.1009	0.91	0.3179
M5	Expanded Vegetation Management	2018	2023	$ -	$ 370	0.38	0.0010	1.19	0.0032
M6	Microgrids	2021	2023	$ 10	$ -	0.00	0.0000	0.00	0.0000
M7	Enhanced Situational Awareness	2018	2023	$ 31	$ 26	0.85	0.0149	3.13	0.0551
M8	Fusing Mitigation	2018	2020	$ 68	$ 23	0.23	0.0025	0.71	0.0078
M9b	Fire Resistant Poles (M1b Scope)	2018	2023	$ 55	$ -	0.23	0.0042	0.85	0.0155
			Total	**$5,775**	**$447**	**7.90**	**0.0013**	**26.09**	**0.0042**

A. Overview

In Alternative Plan #2, SCE chooses to rely on underground conversion (M1b) and only selects covered conductor for a portion of the targeted circuits (M1b uses underground conversion for the portions of circuits targeted as CFO). In contrast, the Proposed Plan uses covered conductor (M1) for those same portions. Underground conversion is more effective than covered conductor in addressing fire risk, but is substantially more expensive.

Finally, in scoping the use of fire-resistant poles, Alternative Plan #2 selects M9b, while the Proposed Plan uses M9. M9b involves only replacing poles associated with the portions of circuits designated as short circuit duty. Since Alternative Plan #2 includes underground conversion, the scope of M9b will include fewer fire-resistant poles, since none are required for underground portions of the system. Besides the underground conversion, Alternative Plan #2 also include microgrids (M6). Microgrids provide limited incremental reliability benefits to mitigate outage impacts related to PSPS.

Like Alternative Plan #1, the remaining control (C2) and mitigations (M2 through M5, M7, and M8) for Alternative Plan #2 are identical to the Proposed Plan. This control and these mitigations are not impacted by the choice to use underground conversion for selected portions of circuits to be hardened.

B. Execution feasibility

The execution feasibility of this alternative is significantly impacted by using underground conversions (M1b). As described in Section IV.B, undergrounding overhead lines is considerably more complex than overhead construction, even with covered conductor. This complexity increases the construction time and costs, which impacts available resources.

The complexity also adds to the time needed to mitigate the same quantity of circuit miles. This meaningfully decreases the feasibility of executing Alternative #2. These execution challenges influenced SCE in determining that this alternative was not the most prudent one.

C. Affordability

Alternative Plan #2 gives an increase in risk benefits at substantially increased costs compared to the Proposed Plan. Notably, Alternative Plan #2 reflects the fact that this portfolio (including substantial undergrounding) provides approximately 3% incremental risk benefit on a mean basis compared to the Proposed Plan. But Alternative Plan #2 is approximately *three times as expensive* as the Proposed Plan. This principally drives the lesser RSE of Alternative Plan #2 compared to the Proposed Plan. As such, it appears that Alternative Plan #2 does not provide the most value in addressing wildfire risk.

D. Other Considerations

The constraints associated with this alternative are similar to the Proposed Plan. However, when compared to overhead lines, underground lines have several drawbacks that were not captured in the modeling and analysis. Underground systems:

- are more difficult to repair;
- cannot be visually inspected;
- require service interruptions to repair; and
- are more difficult to troubleshoot in emergencies, which can lead to longer outages.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

Through the RAMP process, SCE has learned some important lessons in degrees of confidence in modeling mitigation effectiveness, constraints and limitations of the bowtie structure, and mitigations that cannot be easily modeled. Each area is discussed below.

1. Constraints of Bowtie-Structured Analysis

Use of the bowtie structure can limit our ability to assess the complete suite of risk benefits and tradeoffs associated with mitigations assessed in this chapter.

For example, the triggering event – i.e., the center of the bowtie – for wildfire analysis is an ignition associated with SCE in the high fire risk area. However, SCE's wildfire mitigation strategy focuses not only on fire prevention (i.e., reducing potential ignitions) but also suppression (i.e., more rapid identification and assessment of wildfires) and enhancing system resiliency (i.e., more robust design that can withstand damage during wildfires).

Because the triggering event in this analysis was limited to fires associated with SCE facilities, the fire prevention benefits of SCE's controls and mitigations are represented. However, the full suppression benefits and system resiliency benefits of SCE's controls and mitigations are understated, because these are benefits apply to *all fires*, not just SCE-associated fires.

Some operational measures such as PSPS [M5] have operational risks that are likewise understated due to the bowtie structure. The triggering event in the bowtie limits the analysis to fire ignition events. Implementing PSPS results in de-energizing selected circuits under Red Flag conditions, but it is virtually guaranteed that there will be more de-energized circuits then there will be ignitions avoided. The reliability "risk penalty" for de-energization (CMI for customers on these circuits) will accrue for all PSPS implementation events, but the risk analysis only evaluates the smaller number of ignition events. Therefore, the center of the bowtie itself prevents a complete analysis of all of the adverse operational risks associated with PSPS implementation.

2. Mitigation Benefits Not Captured in the Risk Analysis

SCE modeled the risk benefits of mitigations relative to the risk being evaluated in the chapter. Sometimes, a mitigation (such as M9 – Fire-Resistant Poles) can provide benefits in reducing the risk associated with ignitions associated with SCE. A mitigation like fire-resistant poles can also provide benefits in connection with fires that are not associated with SCE. In other words, the scope of this chapter necessarily focuses on fire ignitions that are associated

with SCE. But a fire-resistant pole is "indifferent" to the cause of the fire. Its resistant capabilities will apply regardless of who or what caused the fire.

Additionally, the benefits of fire-resistant poles (and several other controls and mitigations in this chapter, and others) will continue beyond the six-year RAMP window.[73] Accordingly, the total benefits of these poles, as modeled in this chapter, are understated, since our analysis focuses on risk benefits over the 2018-2023 period.

B. Data Collection & Availability

To develop consequence distributions for modeling purposes, SCE utilized data reported by CalFire for statewide fires greater than 300 acres, with a cause classified by CalFire as "Electric Power." The data was collected in October 2018, and 2017 fire data was not yet available within the Redbooks that CalFire publishes. Given the significance of the 2017 fire activity, SCE reviewed news releases issued by CalFire to collect data on several additional fires from 2017 that had a cause classified by CalFire as being "caused by trees coming into contact with power lines" or being "caused by electric power and distribution lines, conductors and the failure of power poles."[74]

SCE also faced challenging data collection and availability issues regarding consequence models for fires. For example, the CalFire data was not immediately helpful for developing serious injury, fatality, and financial consequence models for smaller fires. Generally, the CalFire data provided far less information on the financial and safety consequences of smaller fires.

SCE faced a different data challenge in modeling the reliability consequences for both small and large fires. In general, SCE has a large and robust data source for outage information (ODRM). Unfortunately, while this database captures CMI outage characteristics for fire-related outages in the SCE system, it does not include details of the corresponding fire characteristics

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[73] Please see the Appendix in Section IX for additional detail

[74] 2017 fires that were identified in 2018 CalFire press releases that were included within analysis include: La Porte, Lobo, Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket, Atlas, Cascade, and Liberty fires. These links provide the specific detail:
http://calfire.ca.gov/communications/downloads/newsreleases/2018/2017_WildfireSiege_Cause%20v2%20AB%20(002).pdf
http://calfire.ca.gov/communications/downloads/newsreleases/2018/2017_WildfireSiege_Cause.pdf
http://calfire.ca.gov/communications/downloads/newsreleases/2018/Cascade%20Fire%20Cause%20Release.pdf
http://www.rvcfire.org/Documents/NEWS%20RELEASE%20-%20CAL%20FIRE%20INVESTIGATORS%20RELEASE%20CAUSE%20OF%202017%20LIBERTY%20FIRE.pdf

(i.e., larger or smaller, Red Flag or non-Red Flag Days, SCE- or non-SCE-associated ignition). Because ODRM is a circuit-level outage database and not a fire-related outage database, some assumptions were required to translate circuit-level outage details into fire-level outage consequence distributions for reliability.[75] As a future opportunity for improvement, directly tracking CMI consequences of fires in fire databases would be preferable to attempting to merge separate fire and outage databases.

C. Performance Metrics

The following metrics can help track performance related to wildfire risk:

1. Fire Ignitions Associated with SCE Equipment

This metric relates to ignitions occurring in SCE's service area. Specifically, SCE tracks Commission-reportable ignitions related to SCE electrical equipment or workers, that meet all of the following criteria: (1) A self-propagating fire of material other than electrical and/or communication facilities; (2) The resulting fire traveled greater than one linear meter from the ignition point; and (3) SCE has knowledge that the fire occurred at the time of filing the report. This metric represents the triggering events associated with the wildfire risk bowtie.

2. Covered Conductor Installed in HFRA

This metric tracks the number of circuit miles of covered conductor installed in SCE's HFRA. This metric is directly associated with M1, which aims to reduce the drivers that lead to ignitions. The quantity of covered conductor installed represents the extent to which SCE's overhead distribution lines in HFRA are hardened and represents a leading indicator for fire ignitions. SCE's target for this metric, at this time, is 2,426 circuit miles from 2018 through 2023.[76]

---

[75] For small fires, SCE used ODRM "CMI per circuit" data from fire-related cause codes with major event days (MEDs) excluded, as the basis of a CMI consequence distribution for small fires. The two underlying assumptions in this methodology are that (a) small fires will not be enough to trigger MEDs, and (b) small fires are generally individual circuit outage events.
For large fires, SCE used ODRM "CMI per day" data from fire-related causes codes with MEDs included, as the basis of a CMI consequence distribution for large fires. The two underlying assumptions in this methodology are that (a) large fires may be enough to trigger MEDs, and (b) large fires are most likely to be events that impact multiple circuits. In general, SCE expects that this methodology will understate CMI/fire for large fires that span multiple days, but will overstate CMI/fire for large fires where multiple fires burn on the same day. For purposes of RAMP, SCE assumed that these two factors will generally offset each other and result in a reasonable reliability consequence distribution for large fires.
[76] The 2,426 circuit miles identified includes four circuit miles completed prior to the GS&RP filing (A. 18-09-002), 592 miles described in the GS&RP filing through 2020, and 1,830 miles estimated to be required

3. Branch Line Fusing in HFRA

This metric tracks the number of fusing locations addressed by M8 (Fusing Mitigation) in HFRA. This mitigation measure aims to reduce ignitions when faults occur on distribution branch lines in HFRA. Because Fusing Mitigation encompasses all branch lines for portions of circuits that traverse HFRA, it represents another measure for hardening distribution circuits in HFRA. SCE's plan, at this time, is to address 15,613 fuse locations from 2018 through 2020,[77] by installing or replacing fuses on branch lines with faster acting current-limiting type fuses.

for reconductoring for 2021-2023. The 2021-2023 estimate will be reviewed and potentially revised prior to SCE's 2021 GRC application.

[77] Please see discussion at Section IV regarding Fusing Mitigation (M8).

IX. Appendix 1: Long Term Analysis of M1 – Wildfire Covered Conductor Program

Long-lived assets that are installed during the 2018-2023 RAMP period continue to operate and provide risk reduction benefits for many decades afterward. To provide an illustrative example of capturing the long-term benefits of such assets, SCE piloted a limited study focusing on covered conductor. Use of covered conductor is represented as M1 (Wildfire Covered Conductor Program).

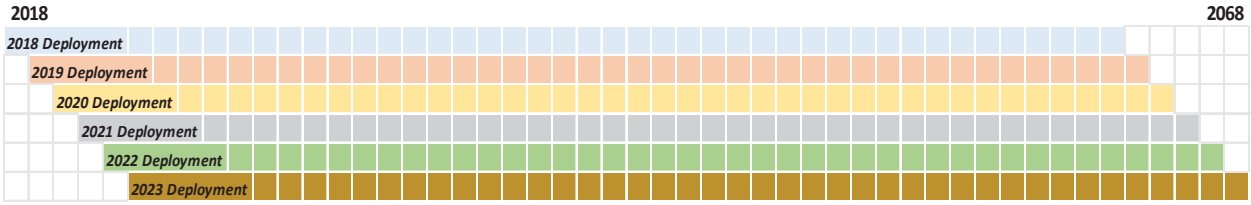
The RAMP analysis is extended out to 50 years to estimate the full benefit that the covered conductor assets provide over their useful life.

For purposes of this limited study, SCE made the following simplifying assumptions:

- 45 years of useful life for the deployments made each year during the RAMP period;
- No degradation occurring during the 45-year period;
- No benefits occurring after the 45-year period;
- No discounting of costs or benefits; and,
- M1 is run as a stand-alone portfolio with no other mitigations / controls.[78]

Figure IX-1 illustrates the full timeline when covered conductor is deployed during the RAMP period:

Figure IX-1 – Deployment of M1 (Wildfire Covered Conductor Program)

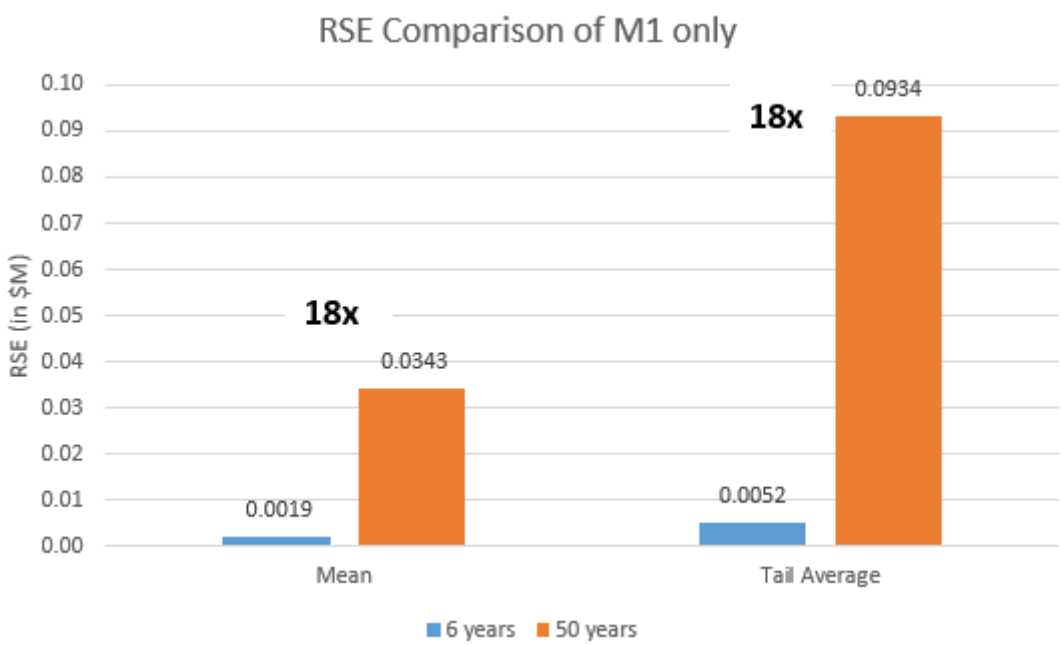


The chart below illustrates the Risk Spend Efficiency (RSE) for covered conductor (M1) for the 6-year RAMP period and the RSE for a 50-year period. The chart includes comparisons using both mean and tail average results.

[78] See Chapter 2 - RAMP Model Overview, Section 3, for discussion on scenarios with multiple mitigations.

Compared to the 6-year RAMP period analysis, the long-term RSE increases approximately 18 times on a mean basis, and increases approximately 18 times on a tail-average basis. This is shown in Figure IX-2.

Figure IX-2 – Short and Long-Term RSE Comparison of M1



For additional detail on performing long-term risk analyses, please see Chapter 8 (Hydro Asset Failure), Appendix 1. In that Appendix, SCE pilots a full long-term evaluation on the entire Hydro Asset Safety chapter, and includes more robust discussion on the impacts involved in modeling risk and mitigations beyond the RAMP period.

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Underground Equipment Failure

Chapter 11

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

In this chapter, we evaluate the risk to SCE, its electrical system, and the public resulting from underground electrical equipment failing. SCE has constructed a risk bowtie to quantify the potential safety, reliability, and financial consequences resulting from this risk.

SCE's Proposed Plan for this risk encompasses elements of SCE's Distribution Infrastructure Replacement (DIR) program, including the existing Worst Circuit Rehabilitation Program, the existing Cable in Conduit Replacement Program, the existing Underground Oil Switch Replacement Program, and a new Covered Pressure Relief and Restraint (CPRR) program. The existing programs directly influence the frequency of this risk. The new program reduces the severity of the impact when the risk does occur. SCE also contemplated two alternative plans that include adding a new mitigation aimed at further reducing the frequency of occurrence.

B. Scope

The scope of this chapter is defined in Table I-1.

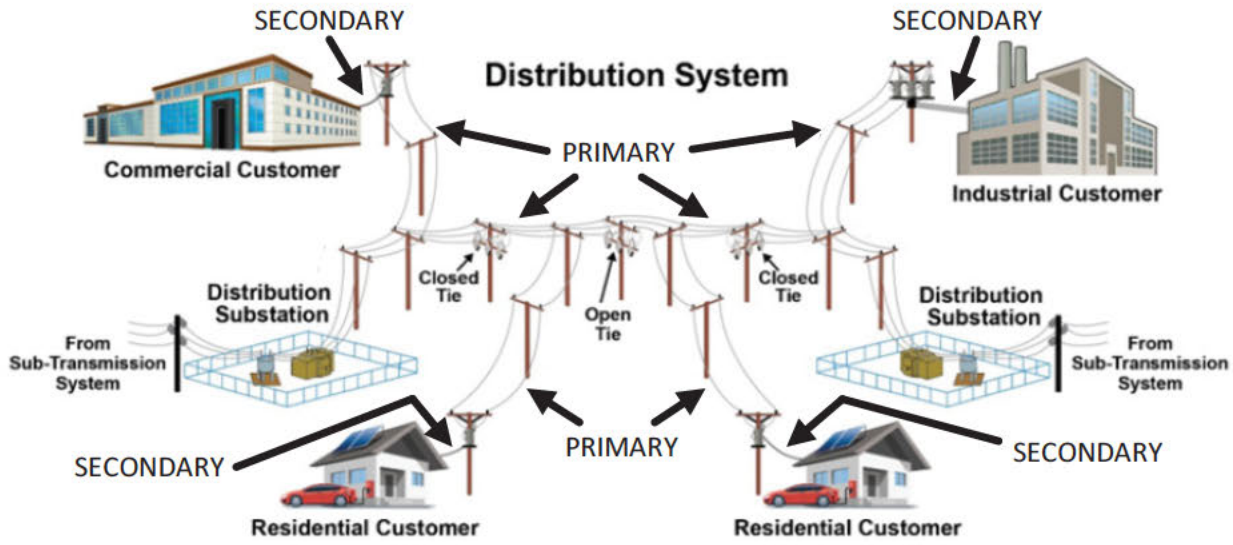
Table I-1 – Chapter Scope

IN SCOPE	Primary distribution UG electrical equipment failure that could potentially lead to a vault or manhole explosion event.
OUT OF SCOPE	• Events initiated by human performance (which would be covered in Chapter 7 - Employee, Contractor, and Public Safety); • Events initiated by UG structure deterioration and failure;[1] • Failure of padmounted UG electrical equipment;[2] • Equipment failures leading to explosions within structures without a manhole lid; and, • Secondary distribution systems.[3]

[1] Structural failure of an underground structure itself, such as concrete deteriorating in a vault that has a manhole cover, is not included in this analysis because it is not a driver for the triggering event.
[2] SCE identifies surface-mounted equipment ("padmounted") such as switches, transformers and capacitor banks as part of its underground system. However, failure of such equipment is not likely to result in an explosion within a subsurface structure. Accordingly, failures of such padmounted equipment are not included in this analysis.
[3] Secondary distribution systems are not included in this analysis, because the vast majority of SCE's secondary distribution systems are radial systems; based on available data, such facilities typically are not associated with underground explosions. SCE's Long Beach secondary is an exception to this statement, as we have experienced events in that area in the past. Further discussion is provided in Section II.A – Background.

This scope includes equipment failures on SCE's primary distribution system and excludes failures on SCE's secondary distribution systems. The term "primary" refers to the high-voltage side of distribution transformers, typically 4 kV, 12 kV or 16 kV. The term "secondary" refers to the low-voltage side of distribution transformers, typically 480 V or less. Figure I-1 below is a simplified diagram of the SCE distribution system illustrating the distinction between primary distribution and secondary distribution. While this figure shows overhead distribution facilities, the concepts equally apply to underground distribution facilities as well.

Figure I-1 – Illustration of Typical Primary and Secondary Distribution Systems



The drivers of this risk include the failure of equipment installed on SCE's primary distribution system in subsurface installations. The two outcomes resulting from this risk include (1) the uncontrolled release of energy from a manhole or vault ("explosion"), and (2) contained or controlled ("non-explosion") energy events.

It is important to note that this risk includes explosions explicitly within underground vaults or manholes. SCE recognizes that there are other types of subsurface structures that can also have risks related to equipment-related failures and explosions. For additional discussion, see the data collection discussion in Section VIII.B of this chapter.

C. Summary Results

Table I-2 provides summary information on the controls and mitigations contemplated and included in this chapter, as well as the results of SCE's risk evaluation included in this chapter, using SCE's Multi Attribute Risk Scoring (MARS) framework. SCE discusses in detail in Sections V,

VI, and VII the reasons why SCE is recommending the Proposed Plan at this time, rather than Alternative Plan #1 or Alternative Plan #2.

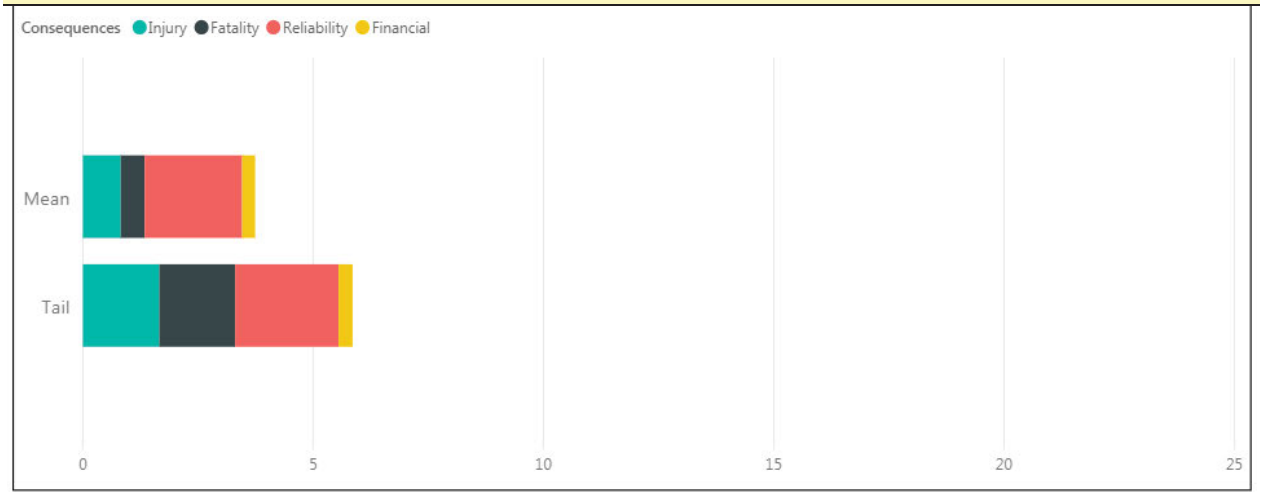
Table I-2 – Summary Results (Annual Average over 2018-2023)

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Cable Replacement Programs (WCR)	X	X	X
C2	Cable Replacement Programs (CIC)	X	X	X
C3	UG Oil Switch Replacement Program	X	X	X
M1	Cover Pressure Relief and Restraint (CPRR) Program	X		
M2	BURD Transformer Replacement			X
Mean (MARS)	*Cost Forecast ($ Million)*	$191.1	$179.8	$180.3
	Baseline Risk	3.7	3.7	3.7
	Risk Reduction (MRR)	0.61	0.48	0.54
	Remaining Risk	3.1	3.3	3.2
	Risk Spend Efficiency (RSE)	0.0032	0.0026	0.0030
Tail Average (MARS)	*Cost Forecast ($ Million)*	$191.1	$179.8	$180.3
	Baseline Risk	5.9	5.9	5.9
	Risk Reduction (MRR)	0.91	0.61	0.69
	Remaining Risk	5.0	5.3	5.2
	Risk Spend Efficiency (RSE)	0.0048	0.0034	0.0038

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I - RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.
C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled this report, and are addressed in Section III.
M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Mitigations are modeled this report, and are addressed in Section IV.
MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.
MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.
RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

Figure I-2 below illustrates the baseline risk associated with underground equipment failure. The mean result is the average result across all simulations. The tail-average result is the average of the most extreme ten percent of simulations. In other words, it indicates lower-probability, higher-impact events. The color coding represents the contribution from each of the risk attributes analyzed within this RAMP report. This figure shows that reliability is the largest impact on a mean basis, while safety impacts become a much larger share of the risk on a tail-average basis.

Figure I-2 – Baseline Risk Composition (MARS)



Maximum MARS is 100.

II. Risk Assessment

A. Background

SCE's electric distribution system covers 50,000 square miles and runs throughout the communities we serve. Electrical components, such as cable, conductor, transformers, switches, etc., are installed above or underneath nearly every street in SCE's service territory. This equipment is necessarily located adjacent to schools, residential neighborhoods, shopping malls, community centers, and entertainment venues. In the SCE electric distribution system approximately one-third of primary conductor miles are installed underground.[4]

As described in SCE's Test Year 2018 General Rate Case (GRC),[5] the equipment installed in SCE's underground vaults can degrade or deteriorate as a result of age, wear, and environmental factors. In addition, underground equipment is inadvertently damaged when vaults and manholes are used by members of the public to improperly dispose of liquids or material such as motor oil, cleaning solvents, etc.

As aging electrical equipment degrades over time, its probability of in-service failure increases. However, underground equipment has unique risks associated with in-service failures because the equipment is contained within relatively small underground vaults or manholes. As a result, underground equipment failures can result in an explosion of combustible gases that build up within the structure. These explosions can forcibly dislodge a vault or manhole cover from its frame, damage streets, and injure the public or utility workers.

SCE, like many other electric utilities, has experienced underground equipment failures resulting in explosions, fires, and smoke events. An article in T&D World states: "For most utilities, maybe only one in 1,000 manholes has an event in a year. But with so many manholes in the U.S., this adds up to approximately 2,000 manhole events per year, or 5.5 events per day."[6]

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[4] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 21, Table III-5; p. 48, line 1.
[5] See A.16-09-001, Exhibit SCE-02, Vol. 8, pp. 7-9.
[6] See http://www.tdworld.com/intelligent-undergrounding/where-theres-smoke. This statistic, while widely reported, is also a very high-level approximation, and includes smoke and fire incidents as well as explosion incidents. For comparison, the SCE system has approximately 40,000 vaults and manholes, and SCE's modeled incidence rate is 20 explosion events per year. Therefore, the apparent incidence rate in the SCE system is roughly equivalent to "1 explosion per 2000 vaults/manholes per year." This suggests that SCE's experience is comparable on an order of magnitude basis to the industry's experience in terms of underground incident frequency. The SCE-specific explosion incidence rate is discussed in greater detail in the "Outcomes & Consequences" section later in the Chapter.

Vault explosions have occurred in SCE's service territory, including but not limited to these recent events.[7]

- SCE's Long Beach District, July 2015 – During outages on two separate days, SCE's system experienced as many as eight vault events (i.e., reports of fire or smoke) and two vault explosions, according to City of Long Beach 911 records.[8]
- SCE's Whittier District, July 20, 2016 – Cable accessory on a distribution circuit failed in service. This resulted in a vault cover being displaced and caused significant damage to a passing vehicle and injury to the vehicle occupant.
- SCE's Huntington Beach District, September 28, 2016 – Cable on a distribution circuit failed in service. This resulted in the vault casting and ladder, portions of the vault vent pipes, and the lid of an adjacent pull box all being displaced.
- SCE's Covina District, November 5, 2016 – Cable on a distribution circuit failed in service. This resulted in a manhole lid being displaced, causing damage to both the manhole lid and the street. The damage from this event is shown in Figure II-4.
- SCE's Covina District, October 23, 2017 – Cable on a distribution circuit failed. This resulted in a manhole lid being displaced, causing damage to the structure, the street, multiple vehicles, and nearby homes.

B. Risk Bowtie

To evaluate the risk of underground equipment failure within SCE's system, SCE has constructed an UG Equipment Failure risk bowtie as shown in Figure II-1. The bowtie presents the risk drivers, outcomes, and consequences with additional detail on each provided in the sections below.

[7] See http://cpuc.ca.gov/AnnualReports for the California Public Utilities Commission Annual Report to the Legislature for details on events reported by California utilities, including reportable underground vault/equipment failures.

[8] The Commission opened an investigation, I.16-07-007, on the Long Beach incident and issued its decision in D.17-09-024. SCE is in the process of improving the Long Beach secondary network system as directed in the Commission's Decision. The Long Beach secondary network makes up a very small percentage of SCE's total underground system, and is not the focus of the Underground Equipment Failure risk as evaluated in this chapter. However, the damage that resulted from the Long Beach incident is an important example of the risks associated with the failure of equipment installed in an underground electrical system.

Figure II-1 – Risk Bowtie

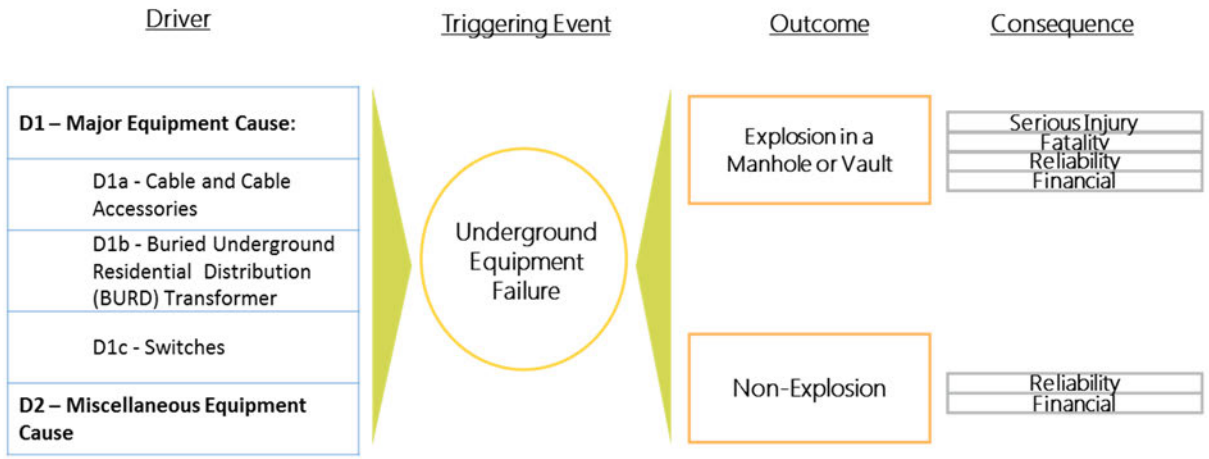
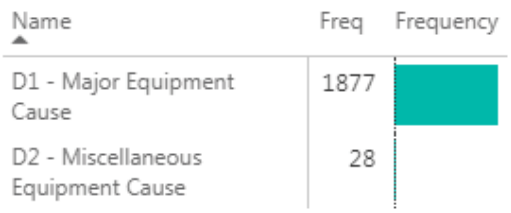


Figure II-2 shows the 2018 projected frequency for drivers that in aggregate compose the triggering events for this risk. Drivers and sub-drivers are described in detail in the section below.

Figure II-2 – 2018 Projected Driver Frequency[9]



Name	Freq	Frequency
D1 - Major Equipment Cause	1877	
D2 - Miscellaneous Equipment Cause	28	

C. Driver Analysis

SCE identified two different categories of drivers on its primary distribution system: D1 (Major Equipment Cause), and D2 (Miscellaneous Equipment Cause).

SCE used its Outage Database and Reliability Metrics (ODRM) system to identify driver frequencies. The ODRM system collects information on all distribution interruptions such as outage location, duration, cause, and number of customers impacted. SCE uses this information to calculate system reliability metrics such as System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI).

[9] Please refer to WP Ch. 11, pp. 11.1-11.2 (*Baseline Risk Assessment Workpaper*).

1. D1 – Major Equipment Cause

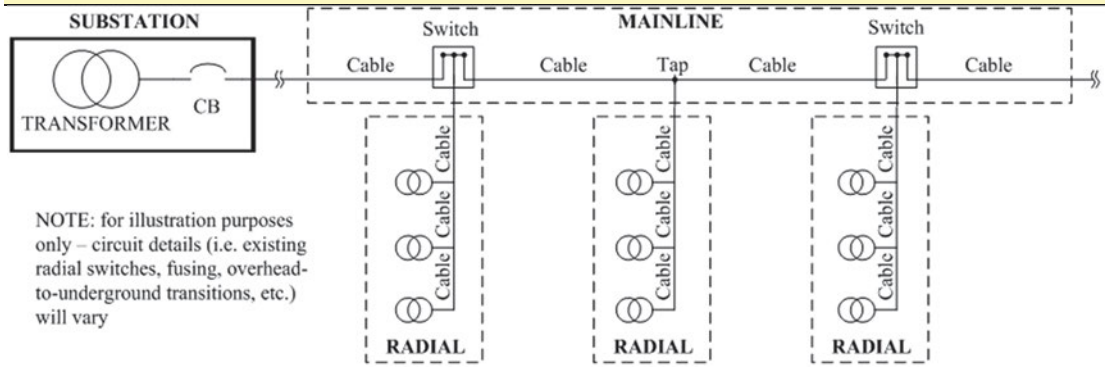
The first category of drivers is identified as "Major Equipment Cause" and includes the major types of underground equipment associated with significant underground failures, including failures of Cable and Cable Accessories, Buried Underground Residential Distribution (BURD) Transformers, and UG Switches.

a. D1a – Cable and Cable Accessories

This sub-category includes in-service failures of distribution cable and related cable accessories such as elbows, junction bars, and splices.

D1a includes the failure of primary voltage distribution cable in both mainline and radial applications. Figure II-3 illustrates mainline and radial cable on a typical distribution circuit. Failure of mainline cable tends to impact more customers, where radial cable failures are isolated to fewer customers.

Figure II-3 – Mainline and Radial Cable Illustrated on a Typical Underground SCE Circuit



The largest population of underground cable installed on SCE's primary system is known as cross-linked polyethylene (XLPE) cable. This cable type was SCE's standard primary distribution cable installed between years 1970 through 1999, and represents approximately half of all primary voltage underground distribution cable installed in the SCE system.[10] For older cable, breakdown of the insulation over time causes cable failure. Typically, external moisture around the cable penetrates through the polyethylene insulation, causing electrical tracking along voids and contaminants in the insulation and forming patterns that look like "trees." This phenomenon of "water treeing" is a common cause of underground cable failure, particularly for XLPE cable.[11] Heat from the electricity running through the cable

[10] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 21, Table III-5.
[11] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 19, lines 21-26.

contributes to thermal decomposition of polymers. This can lead to the generation of combustible gases.[12]

When a cable fails, electricity breaks through the insulation and results in a fault. This fault condition causes an upstream protective device (such as a fuse, automatic recloser, or substation circuit breaker) to operate and cut off power to all customers downstream of the protective device. This fault condition can also release a large amount of energy and, in extreme cases, lead to outcomes such as an explosion in a vault or manhole.

When a cable accessory fails, the resulting consequences can be very similar to the consequences of cable failures themselves. For this reason, SCE has combined cable and cable accessories together for this analysis.

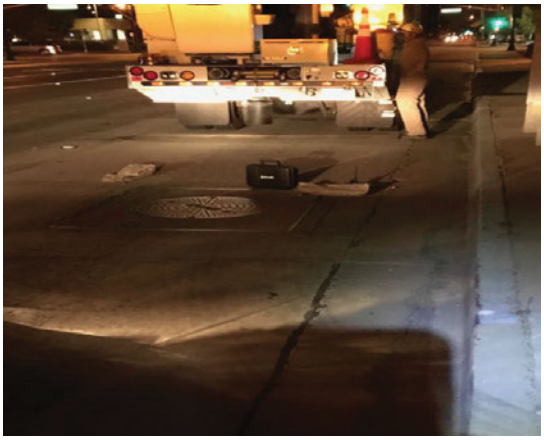
Based on 2015-2017 ODRM data, SCE's system has experienced an annual average of 1,399 failures of cable and cable accessories (approximately 76% of the total annual observed UG Equipment Failures). Approximately 40% of these 1,399 failures are mainline cable failures, and approximately 60% are radial cable failures.

b. D1b – Buried Underground Residential Distribution (BURD) Transformer

This sub-category includes in-service failures of UG equipment known as BURD transformers. Like all distribution transformers, BURD transformers step down voltage from primary voltage levels (typically 4 kV, 12 kV or 16 kV) to voltages utilized by end-use customers. BURD transformers are designed to be used in subsurface applications such as vaults and manholes. Figure II-4 shows a typical BURD transformer installed within an underground vault on SCE's system.

[12] "…intensive thermal decomposition of polymeric material during the development of a manhole event can take the form of either combustion or pyrolysis. The most severe consequences of manhole events are caused by generation of combustible gas during thermal decomposition of polymers." Zhang L., Boggs S. (2009) The electro-chemical basis of manhole events. *IEEE Electrical Insulation Magazine,* 5:25, p. 27. *available at* https://eprcable.ims.uconn.edu/wp-content/uploads/sites/857/2014/09/manhole.pdf

Figure II-4 – BURD Transformer (left) installed in an SCE underground structure (right)



BURD transformer failures can be catastrophic in nature.[13] To illustrate, Figure II-5 shows a picture of a catastrophically failed BURD transformer. In this picture, the top of the transformer shows significant damage caused when the transformer collided with the concrete vault ceiling. The transformer was launched upward when the core and coil were ejected out of the bottom of the transformer housing during the equipment failure.

Figure II-5 – D1b (BURD Transformer): Catastrophic Failure

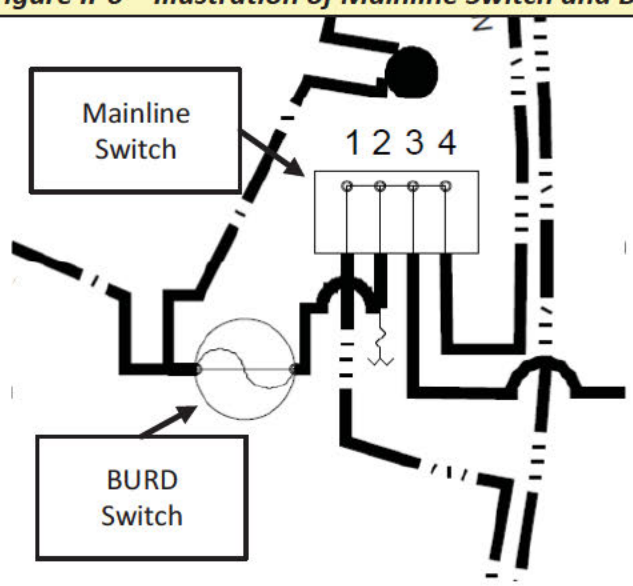
[13] Generally speaking, SCE uses the term "catastrophic" to mean a sudden and complete failure of a piece of electrical distribution equipment associated with an uncontrolled release of energy.

Based on 2015-2017 ODRM data, SCE's system has experienced an average of 328 BURD transformer failures per year (approximately 18% of total annual observed UG Equipment Failures).

c. D1c - Switches

This sub-category includes the in-service failure of subsurface equipment known as switches. Similar to distribution cable, distribution switches will typically fit into one of two types – mainline switches and BURD switches. Mainline switches are typically used to divide mainline circuits into sections or blocks. BURD switches are typically used to separate mainline and radial portions of a circuit. Figure II-6 graphically represents a mainline switch and a BURD switch on a typical SCE underground distribution circuit. Overall, SCE has approximately 16,000 mainline switches installed on its underground system; approximately 1,000 of these are oil-filled switches. SCE also has approximately 17,000 BURD switches installed on its underground system; roughly half of these are oil-filled switches.

Figure II-6 – Illustration of Mainline Switch and BURD Switch



Oil-filled switches are a particular concern to SCE. When an oil-filled switch ages, there can be an increase in dissolved explosive gases within the switch oil. These dissolved gases increase the risk of explosion. Failures of oil-filled equipment can damage adjacent electrical equipment (e.g., cable, transformers, and other switches). This increases the duration of the outage and the scope of restoration. Property damage and injuries can also result from oil switch failures. As stated in our 2018 GRC, SCE plans to continue to preemptively

replace oil-filled subsurface switches with gas-filled or vacuum switches until all such oil-filled switches have been replaced.[14]

Based on three years of historical data (2015-2017), SCE's system has experienced an average of 90 switch failures per year (approximately 4.9% of total annual observed UG Equipment Failures). Approximately 70% of these 90 failures are BURD switch failures, for a BURD switch annual failure rate of approximately 0.4% of the entire BURD switch population. The remaining 30% of these 90 failures are mainline switch failures, for a mainline switch annual failure rate of approximately 0.2% of the entire mainline switch population. SCE attributes the lower annual failure rate of mainline switches to its existing infrastructure replacement program. This program has been replacing aging mainline oil-filled switches every year since at least 2005.[15] As we describe in our 2018 GRC, at this time SCE intends to place greater focus on pre-emptively replacing radial switches as opposed to mainline switches.[16]

2. D2 – Miscellaneous Equipment Cause

The second category of drivers is identified as D2 (Miscellaneous Equipment Cause). This includes all applicable underground equipment failures not included in D1 (Major Equipment Cause). These can include fuses, other isolation devices, underground capacitor banks, and other miscellaneous equipment. Due to the relatively small number of occurrences of equipment failures among these types of equipment, they were grouped together for analytical purposes within this analysis.

Based on 2015-2017 ODRM data, SCE's system has experienced an average of 28 failures per year for equipment that does not fit into driver categories D1a-D1c (approximately 1.5% of total annual observed UG Equipment Failures).

D. Triggering Event

The triggering event is the in-service failure of UG electrical equipment within an SCE underground structure. Based on 2015-2017 ODRM data, in total, SCE is experiencing an average triggering event frequency of 1,845 UG Equipment Failures per year.

To account for equipment aging, SCE modeled failures due to D1 – Major Equipment Cause with an approximately 3% annual growth rate.[17] SCE modeled no annual growth in failures due to D2 - Miscellaneous Equipment Cause because of the relatively small size of the driver

[14] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 57, lines 6-7.
[15] See A.10-11-015, Exhibit SCE-03, Vol. 3, p. 44, Table II-10.
[16] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 57, lines 7-10.
[17] Please refer to WP Ch. 11, pp 11.1-11.2 (*Baseline Risk Assessment Workpaper*).

category and the wide variety of equipment that could be included in this category. The resulting triggering event frequency for years 2018 through 2023 is shown in Table II-1.

Table II-1 – Forecast Annual Triggering Events[18]

Full Name	2018	2019	2020	2021	2022	2023
Underground Equipment Failure						
Baseline	**1,904.56**	**1,966.07**	**2,029.60**	**2,095.21**	**2,162.97**	**2,232.96**
Driver						
D1 - Major Equipment Cause	1,876.56	1,938.07	2,001.60	2,067.21	2,134.97	2,204.96
D2 - Miscellaneous Equipment Cause	28.00	28.00	28.00	28.00	28.00	28.00
Total	**1,904.56**	**1,966.07**	**2,029.60**	**2,095.21**	**2,162.97**	**2,232.96**

E. Outcomes & Consequences

Figure II-7 shows the likelihood of each of the two outcomes occurring when there is an in-service failure of UG electrical equipment within an underground structure.

Figure II-7 – 2018 Outcome Likelihood

Name	%	Percent
O1 - Explosion in a Manhole or Vault	1.1 %	
O2 - Non-Explosion	98.9 %	

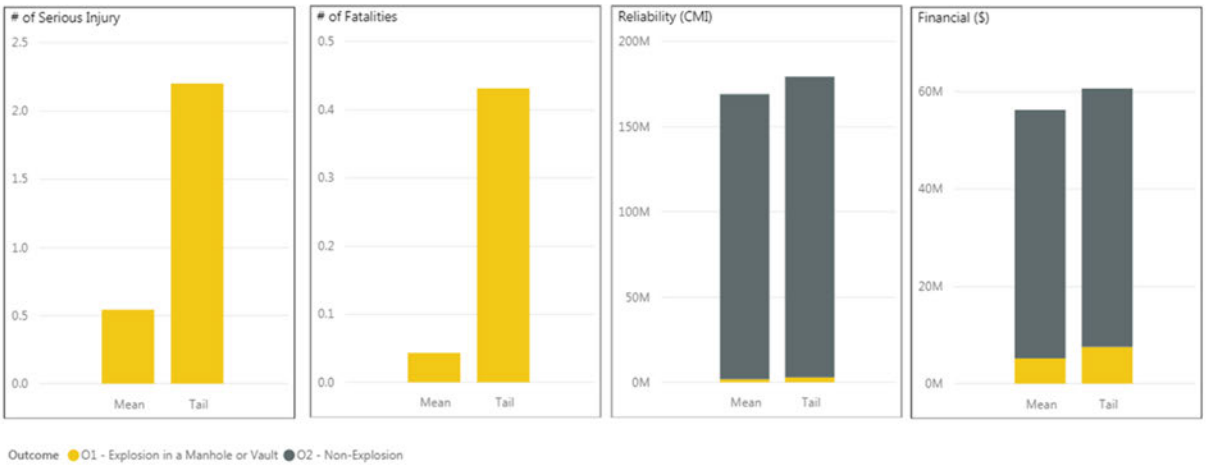
SCE relied upon historical data to determine the likelihood of each outcome occurring. Prior to 2018, data related to underground equipment failures within a vault or manhole was captured in Repair Order form. SCE had first attempted to extract the necessary data from these forms, but our ability to reasonably access this data proved to be insufficient for RAMP

[18] Refer to WP Ch. 11, pp 11.1-11.2 (*Baseline Risk Assessment Workpaper*).

modeling purposes.[19] As such, in 2018 SCE implemented a new data tracking process called the Cover Pressure Relief and Restraint (CPRR) Event Tracker. SCE used this data to determine outcome likelihood for this risk.[20]

Figure II-8 illustrates the composition of the modeled baseline risk in terms of each consequence dimension, shown in natural units, on a mean and tail-average basis. The sections that follow detail the inputs used to derive these results.

Figure II-8 – Consequences by Outcome



1. O1 - Explosion in a Manhole or Vault

For this RAMP analysis, SCE uses the term "explosion" to refer to the uncontrolled release of energy from an underground vault or manhole caused by equipment failure on the distribution system. This outcome can result in displaced manhole covers, other pieces of flying debris, and/or significant damage to roadways or sidewalks. All of these can pose a risk of serious injury or fatality to the public. For example, Figure II-9 shows the damage to an SCE manhole and a public street associated with a vault explosion triggered by a failed distribution cable (D1a).

[19] A Repair Order (RO) is a form initiated by field personnel as they first respond to circuit interruptions or other trouble calls. The form is used by field personnel to identify the type and size of needed repair crews, and to provide a detailed list of material and equipment required to make repairs. SCE found that the historical RO forms did not explicitly classify underground equipment failures on a basis that could be mapped to this RAMP bowtie. In light of this uncertainty, it was not possible to determine credible outcome percentages based on the available RO data.

[20] The CPRR Event Tracker is a system that began collecting underground explosion data in 2018. The CPRR Event Tracker helps SCE track underground structure explosion data across all underground structures in the SCE system. Data for the tracker is reported from field crews through SCE's Grid Operations organization to the Underground Structures Management group, where it is uploaded into the CPRR Event Tracker itself.

Figure II-9 – Illustration of Explosion Outcome (O1) due to Cable Driver (D1a)

Based on SCE's CPRR Event Tracker Data, SCE has observed a rate of approximately 20 explosion events per year in underground vaults or manholes. With a triggering event frequency of 1,845 equipment failures per year, this results in an outcome percentage of 1.1% of underground equipment failures that result in an explosion in an underground vault or manhole (O1).[21]

Table II-2 summarizes the baseline consequences across risk dimensions for Outcome 1, showing mean and tail risk. The table also summarizes the source data used to develop consequence distributions for this outcome.

[21] SCE recognizes that the CPRR Event Tracker Data – which includes only partial year 2018 data – is not a large data set from which to extrapolate annual expected values of vault or manhole explosions. Going forward, SCE anticipates that this data set will become more robust as additional data is gathered.

Table II-2 – Outcome 1 (Explosion from a Vault or Manhole): Consequence Details

Outcome 1		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	Incidents involving SCE underground equipment that resulted in injuries in 2018; Incidents listed in CPUC annual reports 2015-2017; Developed SME estimate of one serious injury in two years.	A SME estimate was developed to estimate the annual consequences to be one fatality in 25 years.	SCE Evaluated actual underground equipment failure events based on analysis of SCE ODRM Database from 2015-2017.	Average cost of equipment repair resulting from underground equipment failure explosion events.
Model Outputs *(Annual Average)*	NU - Mean	0.5	0.04	1,835,142	$5,194,075
	NU - Tail Avg	2.2	0.43	2,886,326	$7,552,824

2. O2 - Non-Explosion Events

The majority of underground equipment failures do not result in an explosion from a vault or manhole. For purposes of this analysis, these safe failure events are referred to as "non-explosion" events. In such instances, the system operates as designed, and the energy associated with these equipment failures does not exceed the system's capacity to contain or control it.

Based on all available CPRR Event Tracker data, SCE has concluded that 98.9% of UG Equipment Failures result in non-explosion event outcomes (O2). This is equivalent to an expected value of approximately 1,825 non-explosion events per year throughout SCE's service territory.

Table II-3 summarizes the baseline consequences across risk dimensions for Outcome 1, showing mean and tail risk. The table also summarizes the source data used to develop consequence distributions for this outcome.

Table II-3 – Outcome 2 (Non-Explosion Events): Consequence Details

Outcome 2		Consequences			
		Serious Injury	**Fatality**	**Reliability (CMI)**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	N/A	N/A	SCE Evaluated actual underground equipment failure events based on analysis of SCE ODRM Database from 2015-2017.	Average cost of equipment repair resulting from underground equipment failure non-explosion events.
Model Outputs *(Annual Average)*	NU - Mean	N/A	N/A	167,463,798	$51,071,135
	NU - Tail Avg	N/A	N/A	176,712,950	$53,119,027

III. Compliance & Controls

SCE has programs and processes in place today that serve to reduce the frequency of this risk event from occurring, or the impacts of the risk event should it occur. These activities are summarized in Table III-1, and discussed in more detail below.

Table III-1 – Inventory of Compliance & Controls[22]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	2017 Recorded Costs ($M)	
					Capital	O&M
CM1	Underground Detail Inspections (UDI) and Underground Preventive Maintenance	Not Modeled	Not Modeled	Not Modeled	$0	$37
C1	Cable Replacement Programs (WCR)	D1a	O1, O2	R	$135	$0
C2	Cable Replacement Programs (CIC)	D1a	-	-	$74	$0
C3	UG Oil Switch Replacement Program	D1c	-	-	$19	$0

CM = Compliance. This is an activity required by law or regulation. As discussed in Chapter I – RAMP Overview, compliance activities are not modeled in this report. Compliance activities are addressed in Section III.

C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. Controls are modeled in this report, and are addressed in Section III.

A. CM1 - Underground Detail Inspections (UDI) and Underground Preventive Maintenance

1. Description

SCE's UDI and Underground Preventive Maintenance are activities included under SCE's Distribution Inspection and Maintenance Program (DIMP). The goal of DIMP is to meet the requirements of General Orders (GO) 95, 128, and 165 in a way that: (1) follows sound maintenance practices; (2) enhances public and worker safety and maintains system reliability; and (3) delivers overall greater safety value for each dollar we spend by allowing SCE to focus its limited resources on higher-priority risks.

DIMP enables us to prioritize work based on the condition of each facility or piece of equipment and how it potentially impacts safety and reliability. We consider various factors, including the facility or equipment itself, loading, location, accessibility, climate, and direct or potential impact on safety or reliability. DIMP enables SCE to prioritize resources effectively and efficiently to remediate conditions that potentially pose higher risks. This approach follows the Commission's direction under GO 95 and a memorandum of understanding between SCE and the CPUC's Safety and Enforcement Division.

[22] Please refer to WP Ch. 11, pp. 11.3-11.8 *(RAMP Mitigation Reduction Workpaper)* and WP Ch. 11, pp 11.9-11.14 *(Mitigation Effectiveness Workpaper).*

DIMP has three maintenance priority levels. During inspections, SCE inspectors identify and rate conditions observed considering the factors discussed previously. Highest priority items requiring immediate action are assigned Priority 1. Priority 2 items do not require immediate action, but require corrective action within a specified time period. Priority 1 and Priority 2 items may be fully repaired or temporarily repaired and reclassified as a lower priority item. Priority 3 items are lower priority items that involve little or no safety or reliability risk. SCE responds to Priority 3 conditions by taking action at or before the next detailed inspection. These actions may include re-inspecting, reassessing, or repairing. These maintenance priorities are also utilized by Troublemen when responding to trouble calls and emergency situations.

B. C1 - Cable Replacement Programs (Worst Circuit Rehabilitation)

1. Description

SCE's Worst Circuit Rehabilitation (WCR) Program[23] addresses problems of aging or obsolete underground mainline cable, and mitigates the negative consequences of in-service cable failures on system reliability and associated safety risks. The WCR Program focuses on circuits that disproportionately contribute to system reliability, by ranking circuits based on three years of historical reliability performance data and targeting the worst performing 1% of circuits for detailed consideration. Circuit rehabilitation typically involves replacing aging mainline cable on each circuit. The WCR Program also adds circuit enhancements such as automation, automatic reclosers, branch line fuses, and fault indicators.

The current deployment plan for this program includes replacing approximately 1,900 conductor miles from 2018 through 2023. These levels reflect a continuation of existing levels of work, but are subject to change based on year-to-year scoping details, resource constraints, and other details.

2. Drivers Impacted

The WCR Program impacts Driver D1a (Cable and Cable Accessories). The WCR Program replaces aging mainline cable and cable accessories prior to failure, and SCE's ODRM indicates that approximately 40% of cable-related failures are on mainline cable.

3. Outcomes & Consequences Impacted

The WCR Program targets mainline cable that has both a higher probability of failure and a higher reliability consequence of failure. Therefore, the WCR Program impacts reliability consequences associated with underground equipment failures.

[23] Please see A.16-09-001, Exhibit SCE-02, Vol. 8 for a detailed description of the program and its history.

C. C2 - Cable Replacement Programs (Cable-In-Conduit)

1. Description

SCE's Cable Life Extension (CLE) Program and Cable-in-Conduit (CIC) Replacement Program collectively and in concert, address the increasing problems of radial cable failures.

The CLE Program consists of two activities. The first activity is a partial discharge testing activity ("cable testing") which identifies those radial cable segments at greatest risk for imminent failure. The second activity is a cable rejuvenation activity ("cable rejuvenation") that provides life extension benefits by improving the insulation characteristics of aged radial cable. This program does so by physically injecting a silicone-based fluid along the strands of aging underground radial cable. This fluid migrates into the conductor insulation, modifying its chemistry and improving its dielectric strength. Both the cable testing and the cable rejuvenation activities identify cable segments in scope for the CIC Replacement Program, which replaces cables that fail testing, as well as cables that cannot be remediated through cable rejuvenation.

The current deployment plan for this control includes replacement or rejuvenation of approximately 1,600 conductor miles of radial cable through 2023. These levels reflect a continuation of existing levels of work, but are subject to change based on year-to-year scoping details, resource constraints, and other details.

2. Drivers Impacted

The CLE and CIC Replacement Programs impact Driver D1a (Cable and Cable Accessories). These two programs either extend the life of aging radial cables or replace radial cables and cable accessories prior to failure. SCE's ODRM indicates that approximately 60% of cable-related failures are on radial cable.

3. Outcomes & Consequences Impacted

In general, the CLE and CIC Replacement Programs target aging radial cable based on probability of failure and not impact of failure. Therefore, the CLE and CIC Replacement Programs will not impact outcomes or consequences associated with failures.

D. C3 - Underground Oil Switch Replacement Program

1. Description

SCE's Underground (UG) Oil Switch Replacement Program replaces oil-filled switches in underground structures which are approaching the end of their service lives and pose a threat to both system reliability and public and employee safety. SCE plans to continue its program of preemptively replacing oil-filled subsurface switches with gas or vacuum switches

until all oil-filled switches have been replaced. In the recent past, program efforts have focused primarily on mainline oil-filled switches. Going forward, SCE intends to focus pre-emptive switch replacements more on radial switches than on mainline switches because of the greater failure rate of BURD switches and the relatively older age of the existing BURD switch population.[24]

The current deployment plan for this control includes replacing approximately 1,500 oil switches through 2023. These levels reflect a continuation of existing levels of work, but are subject to change based on year-to-year scoping details, resource constraints, and other details.

2. Drivers Impacted

The Underground Oil Switch Replacement Program impacts D1c (Switches). The program replaces both mainline and radial subsurface oil-filled switches prior to failure.

3. Outcomes & Consequences Impacted

In general, the Underground Oil Switch Replacement Program targets specific switches based on probability of failure, rather than impact of failure. As a result, SCE has modeled the program as having no impact on the outcomes or consequences associated with underground equipment failures.

[24] See A.16-09-001, Exhibit SCE-02, Vol. 8, p. 57, lines 7-10.

IV. Mitigations

Besides the controls detailed in Section III, SCE has identified potential new and innovative ways to mitigate this risk. These mitigations are summarized in Table IV-1, and discussed in more detail thereafter.

Table IV-1 – Inventory of Mitigations[25]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted
M1	Cover Pressure Relief and Restraint (CPRR) Program	-	O1	S
M2	BURD Transformer Replacement	D1b	-	-

Consequence abbreviations: Serious Injury - S-I; Fatality - S-F; Reliability - R; Financial - F

M = Mitigation. This is an activity commencing in 2018 or later to affect this risk, and which may continue through the RAMP period.

A. M1 - Cover Pressure Relief and Restraint (CPRR) Program

1. Description

The CPRR Program is a new mitigation program that would deploy a new vault lid technology on SCE's system. Standard unrestrained vault and manhole covers can become projectiles during explosion events. This mitigation would involve replacing standard vault and manhole covers with new technology covers that are designed to both relieve built-up pressure and restrain the cover during explosion events.

SCE has been building expertise in this type of mitigation through research, targeted deployment, and ongoing pilot efforts involving vault lid technologies. For example, SCE began installing tethers on vaults in Long Beach in late 2015, following the vault lid displacement events earlier in that year. Further evaluating these vault lid tethers led to developing a more robust engineering design concept involving vault lid venting and restraint technology in 2016. SCE began piloting this concept in select areas of the system in 2017, and updated underground standards for new construction activities to incorporate this technology. In late 2017 and 2018, SCE began piloting proactive vault lid replacements; this work in ongoing.

The CPRR Program would target the installation of venting and restrained vault lids in approximately 550 vaults and manholes in 2019, and approximately 1,000 vaults and

[25] Please refer to WP Ch. 11, pp. 11.3-11.8 *(RAMP Mitigation Reduction Workpaper)* and WP Ch. 11, pp 11.9-11.14 *(Mitigation Effectiveness Workpaper).*

manholes each year thereafter through 2023, for a total installation count of approximately 4,550 lids by the end of 2023. Installations would be targeted based on location-specific risk factors such as population density, proximity to schools or hospitals, congregating areas, and the nature and type of electrical equipment in the associated underground structures.

2. Drivers Impacted

The CPRR Program is consequence-focused, and would not impact any of the identified drivers.

3. Outcomes & Consequences Impacted

The CPRR Program would impact the safety consequences associated with O1 (Explosion from a Vault or Manhole). The CPRR Program involves the use of new vault lid technology that decreases the likelihood of serious injury or fatality due to a vault explosion event.

B. M2 - BURD Transformer Replacement

1. Description

This is a new mitigation program that would initiate preemptively replacing BURD transformers. SCE does not, at present, have a program targeting preemptive replacement of aging BURD transformers. In this risk analysis, BURD transformer failures were noted to be the second largest driver, with 328 transformer failure events per year at current rates. This amounts to nearly one BURD transformer failure per day in the SCE system.

SCE has approximately 82,000 BURD transformers in its inventory today. This mitigation was modeled as replacing only 100 BURD transformers per year for years 2019-2023 with like-for-like replacements. This assumed replacement rate of only 0.1% of the population each year was selected simply for illustrative purposes in this analysis.

2. Drivers Impacted

Implementing a new BURD Transformer Replacement Program would directly impact D1b (BURD Transformer). Such a program would replace aging BURD transformers prior to failure.

3. Outcomes & Consequences Impacted

A new BURD Transformer Replacement Program would target specific transformers based on the probability of failure rather than the impact of failure. As a result, SCE has modeled the program as having no impact on the outcomes or consequences associated with underground equipment failures.

V. Proposed Plan

SCE has evaluated the controls and mitigations identified in Sections III and IV above, and has developed a Proposed Plan for mitigating this risk. This elements of this Proposed Plan are shown in Table V-1 below.

Table V-1 – Proposed Plan 2018-2023 Totals

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Cable Replacement Programs (WCR)	2018	2023	$ 601	$ -	0.436	0.0007	0.531	0.0009
C2	Cable Replacement Programs (CIC)	2018	2023	$ 368	$ -	2.221	0.0060	2.851	0.0078
C3	UG Oil Switch Replacement Program	2018	2023	$ 110	$ -	0.159	0.0014	0.204	0.0019
M1	Cover Pressure Relief and Restraint (CPRR) Program	2019	2023	$ 68	$ -	0.855	0.0126	1.863	0.0274
			Total - Proposed Plan	**$1,147**	**$0**	**3.671**	**0.0032**	**5.449**	**0.0048**

MARS = Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk outcomes from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR = Mitigated Risk Reduction. The reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE = Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

A. Overview

The Proposed Plan continues to deploy existing controls at specified levels over the RAMP period. This involves executing the WCR, CIC, CLE, Switch replacement, and CPRR programs. The Proposed Plan deploys proven distribution infrastructure replacement programs that help address this risk, with the largest risk reduction and the highest RSE compared to the two alternative plans.

SCE's existing controls primarily reduce the frequency of equipment failures, and in the case of the WCR Program, reduce the reliability impact of equipment failures. However, the efforts will not eliminate all in-service equipment failures. This plan also includes the Cover Pressure Relief and Restraint (CPRR) Program (M1), which would help reduce the potential safety consequences when those failures do occur.

B. Execution Feasibility

Executing the Proposed Plan is feasible. The Proposed Plan largely relies on highly mature work processes, well-understood equipment types, and established work methods. SCE has a high degree of confidence that it can execute these programs at the levels described.

SCE began piloting this concept in select areas of the system in 2017, and updated underground standards for new construction activities to incorporate this technology. In late 2017 and 2018, SCE began piloting proactive vault lid replacements. Based on results to date, SCE has a high degree of confidence in the ability to execute a larger scale CPRR program.

We will use the results of the pilot to help inform future deployment of the program. Accordingly, SCE may refine this mitigation plan in our 2021 GRC, as appropriate.

C. Affordability

This Proposed Plan is the most expensive mitigation plan that SCE considered. However, the Proposed Plan also has the highest RSE and largest risk reduction. Based on these results, the CPRR Program would enhance the overall RSE of SCE's existing portfolio of controls.

D. Other Considerations

Because this Proposed Plan consists of existing and established controls, and we have gained experience executing a pilot for CPRR equipment, SCE does not anticipate other challenges in executing this plan.

VI. Alternative Plan #1

SCE evaluated other options to address this risk. We developed Alternative Plan #1 as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 2018-2023 Totals

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Cable Replacement Programs (WCR)	2018	2023	$ 601	$ -	0.438	0.0007	0.538	0.0009
C2	Cable Replacement Programs (CIC)	2018	2023	$ 368	$ -	2.240	0.0061	2.901	0.0079
C3	UG Oil Switch Replacement Program	2018	2023	$ 110	$ -	0.161	0.0015	0.208	0.0019
			Total - Alternative #1	**$1,079**	**$0**	**2.839**	**0.0026**	**3.646**	**0.0034**

A. Overview

Alternative Plan #1 continues to only deploy existing controls at specified levels over the RAMP period. This involves executing the WCR, CIC, CLE, and Switch replacement. The Proposed Plan deploys proven distribution infrastructure replacement programs that help address this risk.

SCE's existing controls primarily reduce the frequency of equipment failures, and in the case of the WCR Program, reduce the reliability impact of equipment failures.

B. Execution Feasibility

As discussed in Section V, SCE has a high degree of confidence in the feasibility of deploying the existing controls in this plan.

C. Affordability

The Alternative Plan #1 is the least-cost option of the three mitigation plans. The RSE of the Alternative Plan #1 is slightly lower than the RSEs compared to the Proposed Plan and Alternative Plan #1, which suggests that it could be made more cost-effective by adding one or both of the alternative mitigations M1 (CPRR Program) or M2 (BURD Transformer Replacement).

D. Other Considerations

SCE does not currently anticipate other challenges in executing this plan.

VII. Alternative Plan #2

SCE evaluated additional options to address this risk, and developed Alternative Plan #2 as shown in Table VII-1.

Table VII-1 – Alternative Plan #2 2018-2023 Totals

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Cable Replacement Programs (WCR)	2018	2023	$ 601	$ -	0.429	0.0007	0.525	0.0009
C2	Cable Replacement Programs (CIC)	2018	2023	$ 368	$ -	2.178	0.0059	2.812	0.0076
C3	UG Oil Switch Replacement Program	2018	2023	$ 110	$ -	0.156	0.0014	0.201	0.0018
M2	BURD Transformer Replacement	2019	2023	$ 3	$ -	0.462	0.1444	0.596	0.1861
			Total - Alternative #2	**$1,082**	**$0**	**3.226**	**0.0030**	**4.134**	**0.0038**

A. Overview

This Alternative Plan #2 includes all existing controls as described in the Proposed Plan (C1, C2, C3). Alternative Plan #2 adds a new infrastructure replacement program for BURD transformers. As indicated above, the infrastructure replacement program replaces BURD transformers with new ones on a like-for-like basis. This new mitigation, M2 (BURD Transformer Replacement), would further reduce the drivers of underground equipment failures.

More specifically, the second-largest driver of underground equipment failures – BURD transformers – is not directly addressed by any existing control within SCE's DIR programs. M2 would address this gap.

B. Execution feasibility

Because the modeled BURD Transformer replacement program targeted a relatively small number of assets (100 transformers per year), the execution feasibility of Alternative Plan #2 would be similar to that described for the Proposed Plan. SCE is familiar with replacing BURD transformers, and anticipates this program would be conceptually feasible to execute.[26]

[26] In fact, SCE replaces a small number of BURD transformers every year as part of its existing PCB Replacement Program (PCBRP) which was described in Exhibit SCE-02, Volume 8 of SCE's 2018 GRC. Conceptually, if a preemptive replacement program for BURD transformers was initiated, executing the program in a similar fashion to the existing PCBRP might be possible with as little impact as possible on design and construction resources.

C. Affordability

The cost of Alternative Plan #2 is lower than the Proposed Plan, and slightly higher than Alternative Plan #1. Similarly, the RSE of this plan is lower than the RSE of the Proposed Plan, and higher than the RSE of Alternative Plan #1. As currently modeled, M2 (BURD Transformer Replacement) might be a cost-efficient way to increase mitigation activities to address this risk. However, due to the modeling uncertainty discussed in greater detail below, further analysis is needed to justify deploying the mitigation at this point in time.

D. Other Considerations

There are certain modeling considerations that have led SCE to not pursue Alternative Plan #2 at this time.

The mitigation effectiveness modeling of the cable replacement programs (C1 and C2), the underground oil switch replacement program (C3) and of the CPRR Program (M1) are based on detailed analyses previously performed by SCE. At this time, SCE has not performed similar detailed analysis regarding replacing BURD transformers. Instead, SCE relied on much more simplified assumptions to evaluate a conceptual BURD Transformer Replacement Program. These simplified assumptions on how effective the mitigation is have not yet been fully analyzed or vetted through internal engineers and stakeholder review processes.

However, this simplified analysis has given us indications that M2 may be an effective risk mitigation measure. Going forward, SCE intends to perform more detailed risk analysis for M2 in a manner comparable to the analysis performed for C1-C3 and M1. If the results of this additional analysis continues to demonstrate that M2 has a favorable RSE compared to other programs, then SCE will introduce a BURD Transformer replacement program at that time. As applicable, SCE intends to provide an update of this additional analysis in the upcoming 2021 GRC.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

SCE has learned important lessons through this RAMP process in quantitatively modeling long-term benefits. We also gained learning in the consistency of mitigation effectiveness assumptions, and the significance of predictive accuracy for infrastructure replacement programs.

1. Quantitative Modeling of Long-Term Benefits

Quantitatively modeling infrastructure replacement programs requires that we: (a) carefully consider factors like infrastructure aging, and degradation; and (b) examine the benefits over time of near-term investments in assets with long service lives. One of the foundational pillars of SCE's Distribution Infrastructure Program is the aging of SCE's infrastructure and the long-term benefits achieved from infrastructure replacement programs. However, these benefits are not entirely addressed by RAMP analysis, which only assesses risk benefits through 2023. This impacts this RAMP chapter because of the long-life nature of the controls and mitigations discussed. Please also refer to the global discussion of this challenge in the Lessons Learned section in Chapter 1 (RAMP Overview).

2. Consistency of Mitigation Effectiveness Assumptions

It is important to have a consistent framework for determining and modeling mitigation effectiveness to appropriately compare RSEs of controls and mitigations. In the context of this chapter, SCE had performed previous detailed asset analysis of WCR, CIC, Underground Switches, and CPRR Programs. As a result, the RSEs for these controls and mitigations were based on mature analyses and had undergone internal vetting on several occasions. This type of analysis was not available for modeling the mitigation effectiveness of M2 - BURD Transformer Replacements.

Accordingly, at this time, SCE cannot be certain whether the high RSE of BURD Transformer Replacements as shown in our RAMP analysis occurred because the program would be extremely efficient at reducing risk, or because the modeling assumptions for mitigation effectiveness were overly optimistic. When interpreting these results, appropriate consideration must be given to the degrees of confidence in the underlying mitigation effectiveness modeling assumptions.

3. Predictive Accuracy for Infrastructure Replacement Programs

In general, the results show that higher levels of modeled predictive accuracy is associated with higher RSEs for infrastructure replacement programs. In essence, the more accurate that

infrastructure replacement programs can be in targeting assets nearest to failure, the more near-term effectiveness such programs have. SCE has been working to develop predictive analytics techniques for a wide variety of assets, including transformers, switches, cable, and overhead circuitry. SCE believes that these data science approaches are a very strong complement to infrastructure replacement programs, and that investing in predictive accuracy can improve RSE. This improvement in RSE is most apparent for shorter-term periods of analysis, such as within the 6-year RAMP analysis window.

B. Data Collection & Availability

While SCE had access to good-quality data on the driver side of the bowtie, SCE experienced challenges with data availability on the consequence side of the bowtie. SCE has long-established processes and procedures for understanding driver frequencies. But in developing this RAMP analysis, we spent a good deal of time and effort attempting to understand the present rates of the identified outcomes and consequences in the SCE system.

For example, the bowtie shown in Figure II-1 went through multiple iterations of Outcomes as we developed this RAMP analysis. Specifically, SCE's bowtie initially assumed four outcomes: underground explosions; underground fires; underground "smokers" (i.e., underground release of smoke without overt explosion or fire); and underground "silent failures" (i.e., any underground equipment failure that is not an explosion, fire, or "smoker"). We initially selected this four-outcome framework, in part, because of ongoing work in the industry related to analyzing underground explosions.[27]

However, once this framework was selected, SCE immediately began encountering significant obstacles in modeling outcomes this way. The largest problem was that SCE has not been collecting underground performance data in a manner that can readily inform the distribution of outcomes in the model. Trying to extract the necessary data from Repair Orders was insufficient for modeling purposes. SCE had to rely on an alternate data source for outcome modeling. SCE's subsequent implementation of the CPRR Event Tracker significantly improves data collection practices regarding outcomes of underground equipment failures. Based on the

[27] Specifically, SCE is aware that the Insulated Conductors Committee (ICC) of the IEEE Power and Energy Society (PES) is presently drafting a guide for smoke, fire and explosions in underground electrical structures. Because this guide is currently in draft form, it was not available for direct use in this risk analysis. However, the characterization of outcomes in this draft guide – i.e., smoke, fire and explosion – was a convenient starting point for modeling outcomes in this RAMP analysis.

availability of the CPRR Event Tracker, SCE reduced the number of outcomes from four to two, as discussed earlier in this chapter.

These two outcomes as currently defined still do not encompass some existing underground explosion risk. As the name suggests, the CPRR Event Tracker was developed to add greater clarity to the number of events that could be mitigated by a CPRR Program for vaults and manholes. But other types of subsurface structures can also experience explosion events; these events would not be mitigated by CPRR. Examples of these types of structures include surface operable enclosures (SOEs) and completely submersible transformers (CSTs). The lids of these structures differ from conventional vault and manhole lids. The resulting consequences of explosions within these structures could be substantially different than those within vaults and manholes. These risks have not been included in this RAMP analysis. A third outcome – i.e., explosion in a subsurface structure other than a vault or manhole – should be considered for inclusion in future RAMP scoring efforts in this risk area.

Our analysis here illustrates that RAMP risk modeling should be viewed as an iterative process. Developing a model will generate results, which in turn will help us refine the continued development of the model.

C. Performance Metrics

Two potential metrics would be valuable in evaluating underground equipment failures:

- Quantity of CPUC reportable safety incidents associated with underground equipment.
- Quantity of Underground Equipment Failure Events.

Additionally, SCE proposes to track the effectiveness of executing programs by comparing actual infrastructure replacement counts to planned amounts, including:

- Miles of WCR and CIC replaced.
- Number of oil transformers replaced.
- Number of vault lids retrofitted.
- Number of BURD transformers replaced (if applicable).

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Risk Assessment and Mitigation Phase

Climate Change

Chapter 12

Rosemead CA
November 15, 2018

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I. Introduction

A. Executive Summary

1. Overview

SCE is committed to building, maintaining, and operating a safe, reliable, clean, and affordable electric system for the communities that we serve. Meeting this commitment requires understanding the impacts of climate change on our electric system and our customers, and adapting to these changes where necessary.

Climate change is a unique risk for SCE. It cannot be summarily addressed as a singular event with a specific outcome. Rather it is a series of evolving near-, medium-, and long-term impacts that will affect assets, business processes, and customers.

The devastating wildfires that swept through parts of California in 2017 and 2018 demonstrate the serious threat that climate change poses to California's communities and to the environment. Adaptation and resilience in the face of climate change are vital. We are working to address the effects of climate change on our infrastructure and in our communities, and to adapt to the uncertainty of climate-related events.

Since 2015, SCE has been involved in national efforts, partnering with the Department of Energy and with other utilities to accelerate deploying adaptation measures (including technologies, practices, and policies) that will create a more resilient energy system and reduce climate- and weather-related vulnerabilities. SCE has completed an initial analysis of its system using future climate projection models to better understand how to prepare for changes in its environment. In 2018, SCE is refining that analysis and preparing plans to deal with near-, medium-, and long-term climate change impacts. This includes severe weather events that are becoming increasingly frequent and intense, as well as long-term issues such as rising sea levels.

SCE looks forward to working with the Commission and its Staff, other utilities, our customers, and key stakeholders to create comprehensive strategies that address the current and future impacts of climate change across critical infrastructure systems.

2. Scope

The scope of this chapter is defined in Table I-1 below.

Table I-1 – Chapter Scope	
In Scope	How SCE will manage and adapt to the impacts of climate change to our electric system and our customers.
Out of Scope	SCE's actions to reduce greenhouse gas emissions.
Time Periods Evaluated & Methods Used	Due to the unique nature of climate change, this chapter evaluates the climate change risk over *two time periods*, using two separate methods: • **Near-Term Period (2018 – 2023):** In Sections II - VII, SCE performs a risk assessment of climate change over this time period using the same bowtie structure and RAMP risk model used in the other RAMP chapters. SCE calculates risk reduction and risk spend efficiency for various controls and mitigations that will address near-term climate change risks.[1] • **Climate Change Vulnerability and Impact Assessment (2018 to 2050):** In Appendix 1 to this chapter, SCE evaluates the long-term risk posed by climate change, from now through 2050. Here, SCE does not use the bowtie structure or risk model found in other RAMP chapters. Instead, SCE leverages other scientific models and research to analyze climate risks to SCE's assets, business processes, and customers over broader time horizons. This Climate Change Vulnerability and Impact Assessment considers event-based risks (e.g., major storms) as well as more gradual risks (e.g., rising sea levels).

3. Summary Results – Near-Term Period (2018 – 2023)

SCE examined potential consequences from 99th percentile extreme heat events, extreme rain events, and extreme wildfires in the near term (2018-2023). Table I-2 and Figure I-1 summarize the resulting baseline risk analysis, controls and mitigations contemplated, and portfolio results over the 2018 – 2023 period.[2] Further detail is provided in Sections II - VII.

[1] The RAMP risk model is largely designed for risk assessment of drivers that are event-based (such as major storms). Thus other longer-term, non- "event-based" climate change impacts (such as rising sea levels) are assessed in Section IX as part of the Climate Change Vulnerability and Impact Assessment.
[2] In this chapter, SCE is focusing on the mean outputs of the model rather than the tail average outputs. The mean outputs are already the result of a 99th percentile-type year. Accordingly, the tail average of 99th percentile events are exceptionally extreme and unlikely.

Table I-2 – Summary Results: Annual Average Over 2018 – 2023 Time Period

Inventory of Controls & Mitigations		Mitigation Plan		
ID	**Name**	**Proposed**	**Alternative #1**	**Alternative #2**
C1	Emergency Management	x	x	x
C2	Fire Management Program	x	x	x
C3	Climate Adaptation Community Grants*	x	x	x
M1	Climate Adaptation & Severe Weather Program	x	x	x
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	x	x	
M2b	Situational Awareness, Monitoring & Analytics (Max)			x
M3	Distribution System Stress Reduction Program		x	
Mean (MARS)	*Cost Forecast ($ Million)*	$14	$18	$20
	Baseline Risk	4.53	4.53	4.53
	Risk Reduction (MRR)	1.06	1.06	1.10
	Remaining Risk	3.47	3.46	3.42
	Risk Spend Efficiency (RSE)	0.08	0.06	0.05
Tail Average (MARS)	*Cost Forecast ($ Million)*	$14	$18	$20
	Baseline Risk (MARS)	14.57	14.57	14.57
	Risk Reduction (MARS)	3.03	3.05	3.23
	Remaining Risk	11.54	11.52	11.33
	Risk Spend Efficiency (RSE)	0.22	0.17	0.16

CM: Compliance (Not shown in this chart, but addressed in Section III; this is an activity required by law, regulation, etc. As discussed in Chapter I - RAMP Overview, SCE does not model compliance activities in this report, and as such, excludes these activities from this table.)

C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE does model controls in this report.)

M: Mitigation (Activity commencing in 2018 or later to affect this risk. SCE does model mitigations in this report.)

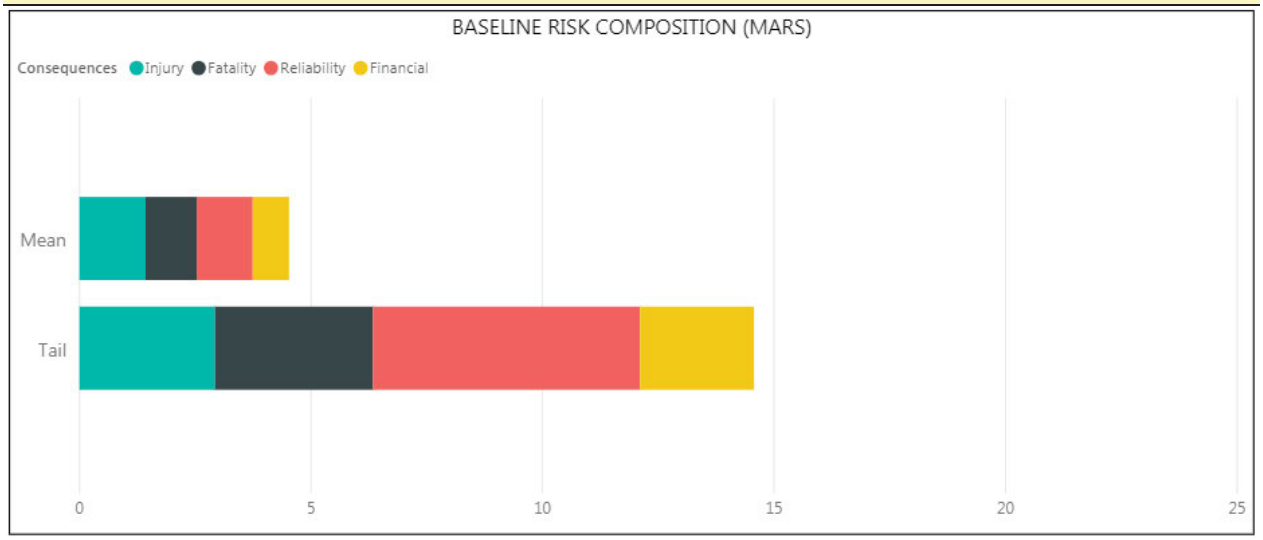
MARS: Multi-Attribute Risk Score. As discussed in Chapter II – Risk Model Overview, MARS is a methodology to convert risk consequences from natural units (e.g. serious injuries or financial cost) into a unit-less risk score from 0 - 100.

MRR: Mitigation Risk Reduction. This is the reduction in risk as measured by the change in MARS values from the baseline risk to the remaining risk after the controls and mitigations are applied.

RSE: Risk Spend Efficiency. As discussed in Chapter I – RAMP Overview, the RSE is a ratio that divides risk reduction in MARS units by the cost to achieve that risk reduction. RSE serves as a measure of the relative efficiency of different options to address a risk.

**C3 is not modeled or included in the costs for this table.*

Figure I-1 – Baseline Risk Composition (MARS)



Maximum MARS is 100.

MARS CONSEQUENCE

AggregationType	Injury	Fatality	Reliability	Financial	**Total**
Mean	1.43	1.10	1.21	0.78	**4.53**
Tail	2.93	3.41	5.77	2.46	**14.57**

The risk evaluation results shown above reflect our near-term risk analysis, which contemplates the annual impacts from identified risk outcomes. On a mean basis, the model contemplates the annual impacts from ten triggering events, including:

- Six instances of major storm events;
- Less than one instance of a catastrophic storm;
- Approximately three instances of increased energy procurement costs due to heat events; and
- Less than one instance of exceptionally high energy procurement costs due to heat events and other compounding factors.

On an annualized, unmitigated basis, the baseline translates to less than two serious injuries per year (1.63); less than one fatality per year (0.20); approximately 97 million Customer Minutes Interrupted; and approximately $157 million in financial consequences.

In comparison, the Proposed Plan is forecast to reduce consequences to approximately one serious injury per year; less than one fatality per year (0.13); approximately 69 million Customer Minutes Interrupted; and approximately $112 million in financial consequences.

4. Summary Results – Climate Change Vulnerability and Impact Assessment (2018 - 2050)

SCE is in the process of completing a comprehensive near-, medium-, and long-term Climate Change Vulnerability and Impact Assessment for the 2018-2050 time period. This assessment will identify and evaluate a comprehensive suite of climate change drivers, including both event-based and more gradual impacts of climate change. This includes analyzing near-term climate impacts resulting from rising sea levels, drought, snowpack, etc., as well as the compounding and cascading impacts that arise from climate change hazards.[3]

Because we do not yet have final results, SCE plans to update its proposed climate change mitigation plan in SCE's Test Year 2021 General Rate Case (GRC) submission.[4] Please see Appendix 1 to this chapter for additional information on this assessment.

B. Climate Change Terminology

In California and across the nation, there are many research efforts, policy discussions, and regulatory proceedings evaluating climate change. It is helpful to understand and match up the terminology that is used across forums. Accordingly, SCE includes guidance here on how we are using terms within this RAMP chapter, relative to these other forums.

SCE defines climate adaptation in the context of climate risks. Climate adaptation means adjusting utility systems and business practices to deal with the current and likely consequences of climate change. Individual climate adaptation actions are also called "controls" or "mitigations" in the context of this RAMP report in order to use language consistent with other RAMP chapters. This terminology is not to be confused with the other common use of the term "mitigation" in the climate change policy arena, which can refer to actions specifically targeted at actually reducing greenhouse gas emissions.

SCE undertakes adaptation efforts in response to projected climate change impacts that are expressed over time in the near-, medium- and long-term. Adaptation strategies and tactics can range from *incremental* (relatively low-investment change to existing processes to be more resilient in the face of climate change) to *transformative* (changes requiring significant investment of time and resources to implement). The range depends on the timing of potential climate change impacts as well as whether potential impacts are extreme, gradual, or cascading and compounding.

[3] Cascading and compounding impacts include hazards that can potentially exacerbate one another, possibly causing greater stress or damage to the electric system.
[4] SCE is scheduled to file its 2021 GRC Application in September, 2019.

C. Climate change increasingly impacts Californians, in the RAMP period (2018-2023) and beyond.

Climate change is already affecting Californians, who now face a "new normal." According to California Natural Resources Agency, the impacts of climate change are evidenced today by the increase in frequency and/or severity of extreme events (e.g., wildfires, heavy rains, and heatwaves), as well as more gradual changes measured over the course of a year, a decade, or longer (e.g., drought, changes in snowpack, sea level rise, and increasing average temperatures). The impacts are also seen in cascading or compounding conditions caused by multiple potential hazards (e.g., rising temperatures result in more frequent drought conditions, which collectively can fuel greater bark beetle infestations, leading to greater tree mortality).[5] Independent state, federal, and non-governmental groups have identified several climate threats[6] that will impact California and pose risks to SCE.

Table I-3 and Figure I-2 describe SCE's two-tiered approach to assessing climate risk in the near- and longer-term. Table I-3 includes a summary of the climate drivers evaluated, the potential impacts (or outcomes) of these drivers, and adaptation actions (or mitigations) we are considering to reduce climate risk. Figure I-2 depicts a comprehensive bowtie describing SCE's overall approach, including drivers and outcomes assessed in the RAMP and Climate Vulnerability and Impact Assessments. This approach builds on the 2016 *Southern California Edison Climate Impact Analysis and Resilience Planning* report. [7]

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[5] *See* California Natural Resources Agency. 2018. *Safeguarding California Plan: 2018 Update, California's Climate Adaptation Strategy, January 2018*, a*vailable at* http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf, pp. 8, 148 and 244.

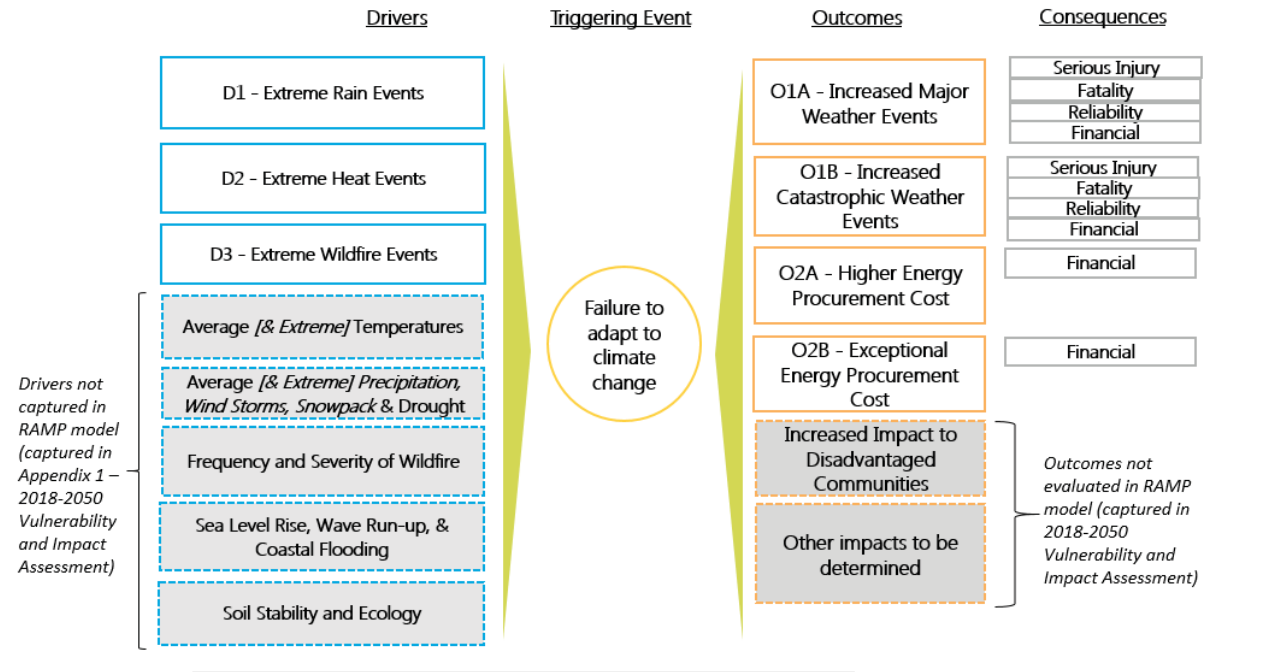
[6] A number of sources, including DOE literature, cite the specific hazards we can anticipate in California. One example is found in the DOE Climate Change and the Electric Sector: Regional Vulnerabilities and Resilience Solutions. This source identifies and evaluates key climate impacts and vulnerabilities by region of the US. California impacts are discussed on pages 3-1 to 3-14, *available at* https://www.energy.gov/sites/prod/files/2015/10/f27/Regional_Climate_Vulnerabilities_and_Resilience_Solutions_0.pdf

[7] Please refer to WP Ch. 12, pp. 12.1 – 12.32 *(2016 SCE Climate Impact Analysis and Resilience Planning Report)*.

Table I-3 – Comparison of Near-Term & Medium- and Long-Term Climate Risk Analyses

	Near-Term RAMP Analysis (2018 – 2023)	**Climate Change Vulnerability and Impact Assessment (2018- 2050)**
Climate and Environmental Drivers Evaluated	• Extreme Heat Events • Extreme Rain Events • Extreme Wildfire Events	• Average & Extreme Temperatures • Average & Extreme Precipitation, Wind, Storms & Snowpack; Severity of Drought • Frequency and Severity of Wildfire • Sea Level Rise, Wave Run-up, & Coastal Flooding • Soil Stability & Ecology (Landslides, Mudslides, and Subsidence, Vegetation, and other Ecological Variables)
Outcomes Evaluated	• Increased Major Storm Events • Increased Catastrophic Storm Events • Higher Energy Procurement Cost • Exceptional Energy Procurement Cost	• Everything in RAMP analysis, plus: • Increased impact to disadvantaged communities • Other impacts to be determined
Mitigations Considered	• Emergency Management • Fire Management • Climate Adaptation Community Grants • Climate Adaptation & Severe Weather Program • Situational Awareness, Enhanced Forecasting & Analytics • Equipment Replacement due to System Stress	• Everything in RAMP analysis, plus: • System hardening • Relocation of assets • Exploration of technology solutions • Changes to business processes, planning, and practices

Figure I-2 – Overall Climate Change Bowtie (2018 – 2050)[8]



To SCE's knowledge, current science as it relates to wind projections is still fairly uncertain, especially in the ability to project changes in extreme (i.e., 99th percentile) wind events. However, wind events that happen concurrently with wildfire or major storm events can cause cascading or compounding impacts (e.g., making the extreme event even worse). Therefore, non-climate environmental drivers (such as wind events) are important factors that SCE must consider to the extent possible. These drivers are included in this longer-term analysis.

Additionally, SCE is examining the potentially disproportionate impact of climate drivers on the vulnerable and disadvantaged communities SCE serves, using existing vulnerability indices such as CalEnviroScreen and the California Healthy Places Index to inform our efforts.

To foster climate resilience on the part of SCE and the communities we serve, the Company is evaluating options over the near-, medium-, and long-term. For example, SCE is exploring ways to:

- Improve infrastructure and systems to enhance resilience (e.g., hardening system components to withstand extreme events; adding more infrastructure to offset system stress as a result of increasing heat; aligning engineering criteria; and adjusting replacement specifications with climate projections);

[8] The drivers which are not event-based were not modeled in the near-term RAMP risk analysis; they are included in grey boxes and will be explored in Appendix 1 through the Climate Change Vulnerability and Impact Assessment.

- Change utility operating practices to mitigate climate change impacts (e.g., changing vegetation management practices, increasing weather and hazard monitoring; increasing predictive modeling capabilities; developing consistent asset planning and load forecasting criteria based on future scenarios using climate models; and planning with customers to address impending hazards like sea level rise and coastal inundation); and
- Increase our outreach to engage communities about climate change impacts and collaborate on ways to mitigate those impacts (e.g., improving grid resiliency in climate vulnerable communities; developing funding opportunities for communities to conduct vulnerability assessments and mitigation strategies; and developing targeted engagement with local governments regarding key hazards that may impact communities and utilities).

D. SCE has formed a Climate Adaptation and Severe Weather Program to facilitate a consistent assessment and mitigation approach across the Company

Much of the efforts we describe in this RAMP chapter will be coordinated by SCE's new Climate Adaptation and Severe Weather Program. The program aims to identify the appropriate framework and criteria to assess and mitigate climate risks, and coordinate the use of this framework on a company-wide basis. SCE describes these efforts in Section IV under the Climate Adaptation & Severe Weather Program mitigation (M1).

SCE's Climate Adaptation and Severe Weather Program builds on our significant climate resilience work to date. It advances the analysis and activities described in the 2016 *Southern California Edison Climate Impact Analysis and Resilience Planning* report, identifying key climate drivers and vulnerabilities impacting SCE over the next 100 years, and proposing mitigation measures to increase climate resilience in the near-, medium-, and long-term.

E. Strong collaboration among public and private stakeholders is necessary to fully understand the near- and long-term effects of climate change.

For SCE to successfully adapt to climate change, we must partner closely with a broad coalition of stakeholders across all sectors – government, private, non-profit, academic, and community-based organizations – to align our goals and resources related to climate change adaptation. *The Company cannot operate independently in preparing for the impacts of global climate change.* The interdependencies that exist between the utility industry, emergency management, and local communities require that any broadly-implemented resilience strategy include each entity.

One example of this type of collaboration occurred in 2015, when SCE became one of 17 utilities to voluntarily join the Partnership for Energy Sector Climate Resilience, a U.S

Department of Energy (DOE) Initiative. The partnership aims to enhance energy security by improving the resilience of energy infrastructure against the impacts of extreme weather and climate change.

SCE is also actively participating in the Commission's Order Instituting Rulemaking (OIR) to Consider Strategies and Guidance for Climate Change Adaptation (R.18-04-019). SCE fully supports the OIR's vision to: (1) understand and assess climate change's potential impact on investor-owned electric and gas utilities' ("IOU") infrastructure; and (2) incorporate appropriate climate adaptation strategies into Commission proceedings and activities, as well as the IOUs' respective planning, operations, and procurement activities.

II. Risk Assessment

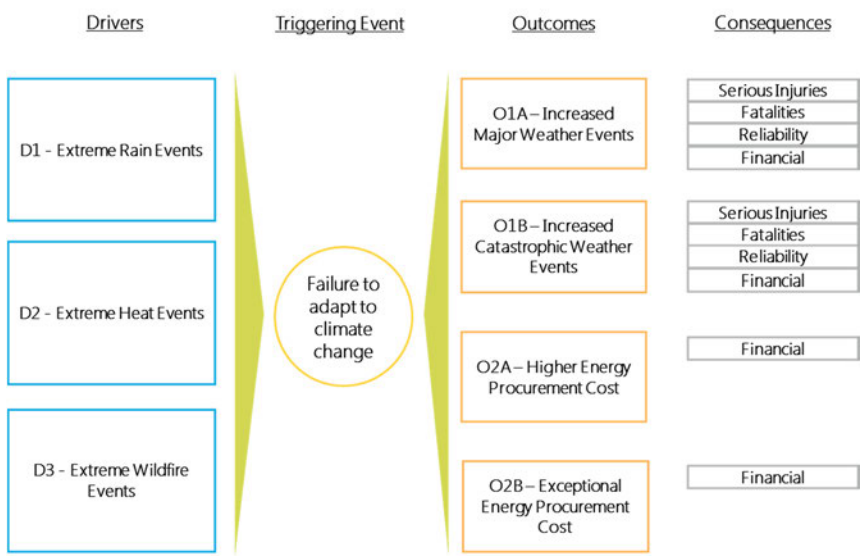
A. Background

Sections II - VII will detail the RAMP model risk assessment that SCE performed on near-term climate change risks from 2018-2023.

B. Risk Bowtie Analysis

Figure II-1 shows the risk bowtie used to structure the near-term Climate Change risk assessment.

Figure II-1 – 2018-2023 Risk Bowtie



C. Driver Analysis

The drivers in this chapter were identified from established climate science literature and common themes in climate models.[9]

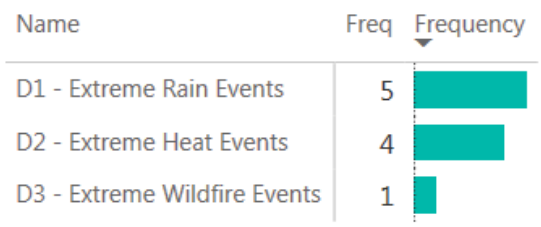
In the RAMP risk model, SCE chose to use "99th percentile" data for each of the three event-based climate drivers. This reflects expected shifting extremes due to climate change in the near-term. These three climate drivers are projected to change compared to historic averages as the climate changes (i.e., more frequent and hotter heatwaves, a downward trend in frequency of extreme rain events, and more extreme wildfires).

[9] See, e.g., Bedsworth, Louise, Dan Cayan, Guido Franco, Leah Fisher, Sonya Ziaja, Statewide Summary Report, *California's Fourth Climate Change Assessment (2018),* publication number: SUMCCCA4-2018-013, *available at* http://www.climateassessment.ca.gov/state/docs/20180827-StatewideSummary.pdf.

These 99th percentile events were calculated based on a combination of historical data within SCE's service area and a range of potential future values, using a mix of SCE temperature and precipitation data as well as CAL FIRE data. We used a statistical modeling method to forecast expected increases (for extreme heat events and extreme wildfires) and decreases (for extreme rain events) associated with a changing climate for the 2018-2023 time period. This analysis is described for each driver in the following sections.

Since the drivers used are representative of 99th percentile events, they can be interpreted as the worst-case weather scenario SCE may face between now and 2023 due to a changing climate.

Figure II-2 – 2018 Projected Driver Frequency Summary



1. D1 - Extreme Rain Events

To capture rare and extreme rain events, SCE used data from 75 weather stations across the Los Angeles/Orange County area. This data was utilized to calculate a 99th percentile rain event.[10] Using this data, we determined that the 99th percentile rainfall event is a cumulative 1.5 inches of rain over 3 consecutive days or less. During such events, the electric system can experience significant strain in the form of outages and storm declarations.[11]

While climate models are suitable for developing forecasts for time horizons beyond 10 years from present, modeling within the 10-year window is limited.[12] Developing projections over near-term timescales (less than 10 years from present) is challenging, due to

[10] Refer to WP Ch. 12, Index of Workpapers *(D1 – Extreme Rain Events)*.
[11] Refer to WP Ch. 12, p. 12.33 *(Sample of Rain Events and Storm Declarations)*.
[12] Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (Eds.). 2013. Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, *available at* http://www.ipcc.ch/report/ar5/wg1/

natural climate variability, including the climate system's inherent randomness.[13,14,15] SCE developed a statistical analysis using historical values to develop projections for mean values in 2018 – 2023. SCE then applied a probability distribution based on the historical distribution of values to better account for uncertainty.

We used data from 2017 back to 1976 to develop a regression and project values for the 2018 - 2023 period. The year 1976 is widely acknowledged as the beginning of a "climate shift," where global temperatures began to increase at least partially due to atmospheric greenhouse gas concentrations.[16]

SCE experienced an average of less than 4 extreme rain events per year from 2014 to 2017. SCE's analysis of data from 75 weather stations indicates a slight downward trend in the number of rain events of this size in the 2018-2023 time period. This near-term variability does not necessarily contradict existing studies that report Southern California may become even wetter due to climate change. Several climate projection models (which span a longer time horizon and consider all rain events) show a potential increasing trend of rain.[17] SCE

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[13] Strategic Environmental Research and Development Program (SERDP) (2016) Climate-Sensitive Decision-Making in the Department of Defense: Synthesis of Ongoing Research and Current Recommendations. US Department of Defense, *available at* https://www.serdp-estcp.org/News-and-Events/Blog/Climate-Sensitive-Decision-Making-in-the-Department-of-Defense-Synthesis-and-Recommendations

[14] Walsh, J; Wuebbles, D; Hayhoe, K; Kossin, J; Kunkel, K; Stephens, G; Thorne, P; Vose, R; Wehner, M; Willis, J; Anderson, D; Kharin, V; Knutson, T; Landerer, F; Lenton, T; Kennedy, J; Somerville, R (2014) Appendix 3: Climate Science Supplement. Climate Change Impacts in the United States: The Third National Climate Assessment, Melillo, JM; Richmond, TC; Yohe, GW; Eds., U.S. Global Change Research Program, 735-789. doi:10.7930/J0KS6PHH, *available at* http://s3.amazonaws.com/nca2014/low/NCA3_Climate_Change_Impacts_in_the_United%20States_LowRes.pdf?download=1

[15] Flato, G; Marotzke, J; Abiodun, B; Braconnot, P; Chou, SC; Collins, W; Cox, P; Driouech, F; Emori, S; Eyring, V; Forest, C; Gleckler, P; Guilyardi, E; Jakob, C; Kattsov, V; Reason, C; Rummukainen, M (2013) Evaluation of Climate Models. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, *available at* http://www.climatechange2013.org/report/full-report/

[16] Trenberth, K.E., P.D. Jones, P. Ambenje, R. Bojariu, D. Easterling, A. Klein Tank, D. Parker, F. Rahimzadeh, J.A. Renwick, M. Rusticucci, B. Soden and P. Zhai, 2007: Observations: Surface and Atmospheric Climate Change. In: *Climate Change 2007: The Physical Science Basis.* Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, page 240, *available at* https://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-chapter3.pdf

[17] Allen, R, & Luptowitz, R. *El Niño-like teleconnection increases California precipitation in response to warming,* Nature Communications 8, published July 7, 2017, *available at* https://www.nature.com/articles/ncomms16055

analyzed only the projected extreme rain events for the 2018 – 2023 period, using a Poisson distribution[18] to represent the distribution's high tail values.

2. D2 – Extreme Heat Events

SCE calculated extreme heat events using effective temperature, which is a weighted average of three consecutive days of heat. Three consecutive days of high heat are commonly represented as a heatwave, which is when we typically see marked increased load and burden on the electric system. Using effective temperature, we analyzed historical trends across several decades. We used recorded daily maximum temperatures from five weather stations located across Southern California to calculate effective temperature across the service territory. SCE identified 101°F as the 99th percentile value for effective temperature, based on averages of effective temperature data from January 2011 – August 2018. We then used data from 2017 back to 1976 to develop a regression, and project values for the 2018 - 2023 period.[19]

SCE expects to be averaging approximately four extreme heat events per year during the 2018-2023 time period. In contrast, between 1976 and 2017, SCE averaged three events per year. Also, most historical Southern California heat waves have occurred from July to September; but as climate warming occurs, these events appear to begin earlier in the season and continue through the fall, while summer events become more frequent and more intense. The increasing tendency for multiple hot days in succession – resulting in heat waves that last longer – could cause problems for transmission and distribution infrastructure. An especially important factor may be the lack of nighttime cooling that has characterized recent heat waves in California. This absence of nighttime cooling can cause additional stress on the transformers and other electrical components that require regular cooling.

3. D3 – Extreme Wildfire Events

For this RAMP analysis, SCE defines Extreme Wildfire Events as the 99th percentile largest wildfire events, based on acres burned.[20] While this analysis evaluated the entirety of SCE's service area, much of our electrical transmission and distribution lines and equipment are

[18] A Poisson distribution is used to model the number of events occurring within a given time interval. In statistical analysis, it is a distribution function that is useful for characterizing events with very low probabilities of occurrence within some definite time or space.
[19] Please refer to WP Ch. 12, Index of Workpapers *(D2 – Extreme Heat Events)*.
[20] Please refer to WP Ch. 12, Index of Workpapers *(D3 – Extreme Wildfire Events)*.

located in high fire risk areas[21] (approximately 35% of SCE's service area is located in high fire risk areas).

Wildfire activity has increased in recent decades.[22] Since 1979, while the number of fires in California decreased, the acreage burned per year increased. Similarly, the average acres burned per fire has increased over the same time period.[23]

While the size and impact of California's wildfires has grown, recently our state has experienced a dramatic increase in year-round, devastating wildfires unlike anything previously seen. In 2017, Southern California experienced "unremitting" Santa Ana winds accompanied by extremely low humidity (as low as one percent) with low single-digit readings even at the beaches; this resulted in "near apocalyptic" fires.[24] Six of the state's 20 most destructive fires have occurred within the last year.[25]

Unfortunately, 2018 has been another devastating year, with low precipitation, returning drought conditions, and record-setting heat occurring as early as July 2018.[26] This year, the state has seen the largest fire in its history with respect to acreage burned, the

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[21] The term "High Fire Risk Areas" refers to the locations in SCE's service territory that have been given a Tier 2 or Tier 3 designation in the most recent CPUC High Fire Threat District maps (CPUC Fire Maps). See D.17-12-024. The term also encompasses any additional locations that SCE had previously identified in its service area as high fire risk areas prior to the release of the most recent CPUC Fire Maps.

[22] *See* National Oceanic and Atmospheric Administration, *Assessing Fire Hazard Risk In Southern California(2018)*, *available a*t https://coast.noaa.gov/digitalcoast/stories/californiafire.html; *see also,* John Abatzoglou &A. Park Williams, *Impact of Anthropogenic Climate Change on Wildfire Across Western US Forests,* PNAS, (October 18, 2016),*available at* http://www.pnas.org/content/113/42/11770.

[23] CAL FIRE Redbooks, 2016 Wildfire Activity Statistics, *available at* http://www.fire.ca.gov/downloads/redbooks/2016_Redbook/2016_Redbook_FINAL.PDF.

[24] Rong-Gong Lin II, *L.A.'s increasingly hot and dry autumns result in "these near-apocalyptic fires,"* L.A. Times (December 21, 2017), *available at* http://www.latimes.com/local/lanow/la-me-ln-weather-thomas-fire-20171221-story.html.

[25] CAL FIRE statistics as of August 20, 2018. Does not include Mendocino Complex fire, which is currently the largest in California's history (acres burned) but not within the top 20 most destructive (structures destroyed). Structures include homes, outbuildings (barns, garages, sheds, etc.) and commercial properties destroyed.

[26] National Interagency Fire Center, *Southern and Central California Monthly/Seasonal Outlook* (Aug. 2018), *available at* https://gacc.nifc.gov/oscc/predictive/outlooks/myfiles/assessment.pdf. (Note that this website is updated daily, and the numbers may have increased since August 2018)

Mendocino Complex Fire.[27] As of August 9, 2018, California's wildfires have burned over 1,121,916 acres,[28] damaged or destroyed over 2,500 structures,[29] and resulted in six fatalities.[30]

Experts had predicted that decades from now climate change would increase the risk of these uncharacteristically large and severe wildfires, including a potential increase in the total area burned.[31] However, it appears that these projected impacts are happening now, and regrettably ahead of some forecasts. Shortly after the Mendocino Complex Fire, Governor Brown explained that "[t]he more serious predictions of warming and fires to occur later in the century, 2040 or 2050, they're now occurring in real time."[32] California's recently released Fourth Climate Change Assessment—while acknowledging that projecting future wildfires is complicated—nonetheless notes the potential for greater fire risk in the future and particularly "mass fires" burning large areas simultaneously.[33]

Given that there are tens of thousands of wildfires in California per year, SCE elected to consider only large California wildfires (those that exceed 300 acres, a threshold established by CAL FIRE).[34] SCE identified 100,124 acres as the present day 99th percentile wildfire size, based on data from 2011 – 2017. We then used data from 1979 – 2017 to develop a regression, and project values for the 2018 - 2023 period.[35,36]

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[27] Eric Levenson, *A look at California's largest wildfires by the numbers,* CNN (August 7, 2018), *available at* https://www.cnn.com/2018/08/07/us/california-fire-numbers/index.html.
[28] National Interagency Fire Center ("NIFC"), *National Year-to-Date Report on Fires and Acres Burned by State and Agency* (August 29, 2018), *available at* https://gacc.nifc.gov/sacc/predictive/intelligence/NationalYTDbyStateandAgency.pdf (Note that this website is updated daily, and the numbers may have increased since August 29, 2018)
[29] NIFC, *National Large Incident Year-to-Date Report* (August 29, 2018), *available at* https://gacc.nifc.gov/sacc/predictive/intelligence/NationalLargeIncidentYTDReport.pdf (Note that this website is updated daily, and the numbers may have increased since August 29, 2018)
[30] Sarah Ravani and Lauren Hernandez, *California Wildfires: Firefighter's death the 6th of 2018; Yosemite Reopens*, S.F. CHRONICLE (August 14, 2018), *available at* https://www.sfchronicle.com/california-wildfires/article/Mendocino-Complex-fires-claim-first-life-5-000-13154845.php#photo-15986939
[31] Tania Schoennagel et al., *Adapt to More Wildfire in Western North American Forests as Climate Changes*, (May 2, 2017), *available at* http://www.pnas.org/content/pnas/114/18/4582.full.pdf.
[32] Jaclyn Cosgrove et al., *California fires rage, and Gov. Jerry Brown offers grim view of fiery future,* L.A. Times (Aug. 01, 2018), *available at* http://www.latimes.com/local/lanow/la-me-ln-california-fires-20180801-story.html.
[33] Bedsworth, Louise, Dan Cayan, Guido Franco, Leah Fisher, Sonya Ziaja. (2018). Statewide Summary Report. *California's Fourth Climate Change Assessment.* Publication number: SUMCCCA4-2018-013, *available at* http://www.climateassessment.ca.gov/state/docs/20180827-StatewideSummary.pdf.
[34] CAL FIRE. 2016. Historical Wildfire Activity Statistics, *available at* http://calfire.ca.gov/downloads/redbooks/2016_Redbook/2016_Redbook_FINAL.PDF.
[35] CAL FIRE. 2018. Historical Wildfire Activity Statistics (Redbooks), *available at* http://calfire.ca.gov/fire_protection/fire_protection_fire_info_redbooks.
[36] While SCE originally intended to use data back to 1976, CAL FIRE only provides data on individual large fires back to 1979.

D. Triggering Event

The triggering event, "failure to adapt to climate change," reflects the notion that SCE must adapt and thoughtfully decide when identifying mitigations specifically designed to deal with the diverse impacts that climate change will create for our business. Figure II-3 shows the forecast triggering event frequency composition for each year over the 2018 – 2023 period.

As described in the Driver Analysis section, there is a great deal of variability and uncertainty in expected climate change impacts, especially in the near term. Therefore, the number of triggering events should be taken as directional rather than as a specific expected outcome. The slight decrease in projected triggering events occurs because the growth in projected frequency of extreme heat events and extreme wildfire events is offset by the larger projected decrease in frequency of extreme rain events.

Figure II-3 – Triggering Event Frequency Composition

Risk	2018	2019	2020	2021	2022	2023	**Total**
CMC							
Baseline	**10.72**	**10.58**	**10.44**	**10.29**	**10.15**	**10.01**	**62.19**
Driver							
D1 - Extreme Rain Events	5.31	5.14	4.98	4.81	4.65	4.48	**29.37**
D2 - Extreme Heat Events	4.20	4.22	4.24	4.26	4.28	4.30	**25.50**
D3 - Extreme Wildfire Events	1.21	1.21	1.22	1.22	1.23	1.23	**7.32**

E. Outcomes

SCE identified four main outcomes resulting from the triggering event: increased major weather events, increased catastrophic weather events, higher energy procurement cost, and exceptional energy procurement cost. To do this, SCE: (1) evaluated current experience with climate change impacts on our electric system; and (2) conducted historical and statistical analyses of heat, rain, and wildfire data to forecast climate-driven near-term changes and to assess the implications of these changes on SCE's electric system. Figure II-4 depicts the estimated likelihood of four outcomes that were modeled.

Figure II-4 – 2018 Outcome Likelihood

Outcome Percentage

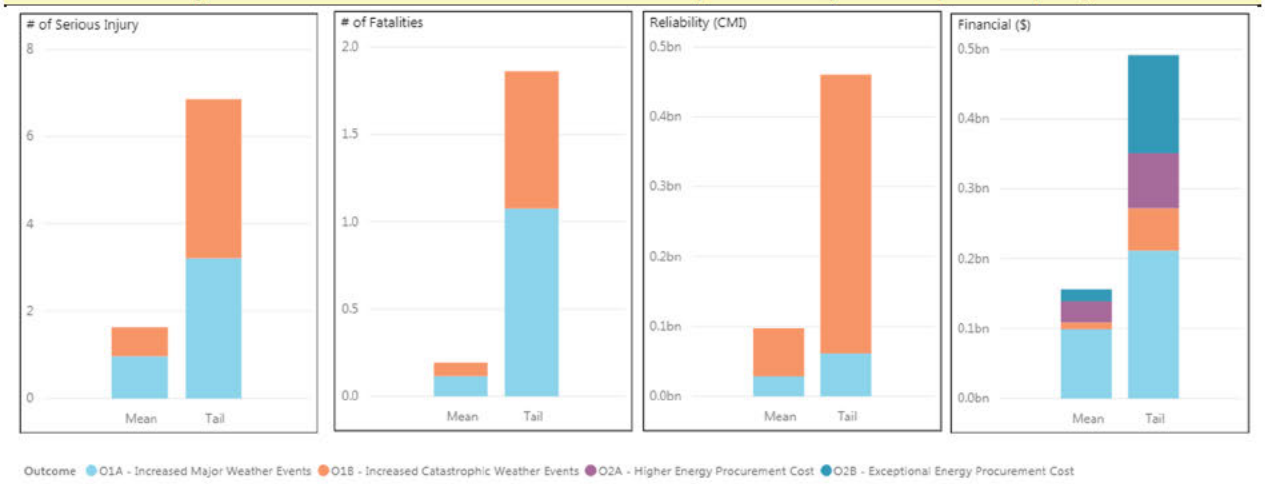
Name	%	Percent
O1A - Increased Major Weather Events	60.0 %	
O1B - Increased Catastrophic Weather Events	5.0 %	
O2A - Higher Energy Procurement Cost	32.5 %	
O2B - Exceptional Energy Procurement Cost	2.5 %	

When ten triggering events per year are applied to these outcome percentages in the model, the following is projected to occur on an annual basis:

- Six instances of major storm events;
- Less than one instance of a catastrophic storm;
- Approximately three instances of increased energy procurement costs due to heat events; and
- Less than one instance of exceptionally high energy procurement costs due to heat events and other compounding factors.

Figure II-5 illustrates the composition of the modelled baseline risk in terms of each consequence. This shows that all of the safety and reliability impacts come from O1A (Increased Major Storm Events) and O1B (Increased Catastrophic Weather Events). These two outcomes also produce the majority of financial consequences associated with this risk. The sections that follow detail the inputs used to derive these results.

Figure II-5 – Modeled Baseline Risk Composition by Consequence (NU)



1. O1A – Increased Major Weather Events

This outcome is defined as facility and infrastructure loss to any of SCE's assets resulting from increasing "major storm events."[37] These events may require major restoration activities, which include remediating damaged transmission and distribution assets, telecommunications equipment, or operational facilities. More frequent or severe extreme rain, heat, or wildfire events could result in more significant outage days, and SCE may need to mobilize and deploy more restoration efforts as a result. SCE has experienced between five to six significant or major storm restoration events per year in the last seven years.

Potential consequences from O1A (Increased Major Weather Events) are summarized on an annualized basis in Table II-1. Safety impacts are associated with injuries or fatalities resulting from storms. Reliability impacts are associated with service interruptions caused by weather events. Financial costs are associated with equipment repair or replacement and restoration activities following weather events. For O1A, the estimate of annual impacts is 0.97 serious injuries, 0.12 fatalities, over 28 million CMI, and over $98 million in financial harm, on a mean basis.

Table II-1 – Outcome 1A (Increased Major Weather Events): Consequence Details[38]

Outcome 1A		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE reviewed worker injuries resulting from storms over 2015 – 2017. Many of these injuries could have easily turned into serious injuries. Based on this, SCE applied an estimate of approximately one serious injury occurring each year during the most extreme storms.	SCE applied a ratio of injuries to fatalities (8.3:1) based on the number of injuries and fatalities accounted for in the National Fire Protection Association's report Fires by Occupancy or Property Type, which uses data from 2010 - 2014.	SCE reviewed representative data on customer minutes of interruption (CMI) from 2014 - 2017 for weather related events (heat days, rain storms, wildfires, etc.). The representative data for identified storms were utilized as baseline inputs to the model. Recorded data shows that SCE experiences between 5-6 major storm events per year.	SCE reviewed data on storm-related expenses (equipment repair and restoration, logistics for procuring new infrastructure, as well as other storm response and recovery activities) from 2014 - 2017. For example the total storm related expenses totalled $65M in 2016 and $97M in 2017. SCE has recorded about 6 major storm events occur per year.
Model Outputs	NU - Mean	0.97	0.12	28,455,249	$ 98,573,300
	NU - Tail Avg	3.21	1.08	61,115,582	$ 211,713,648

[37] A major storm event is defined as significant outage days, where SCE declares a "storm" or restoration event based on damage that may be widespread or extensive enough to require territory-wide coordination. The damage incurred is a result of significantly bad weather such as rain and heat, or weather-driven events like wildfire. SCE also responds to many smaller storm events on a more frequent basis throughout the year.

[38] Please refer to WP Ch. 12, pp. 12.34 – 12.35 *(Baseline Risk Assessment Workpaper)*.

2. O1B – Increased Catastrophic Weather Events

This outcome is defined as catastrophic facility and infrastructure loss resulting from extreme weather events. This includes similar assets to those described in Outcome 1A. However, Outcome 1B focuses on rare compounding or extreme conditions such as a string of extreme heat or rain events that can lead to catastrophic loss. These types of events may be physically isolated but can cause complex impacts. For example, significant rainfall in some parts of the SCE territory may result in landslides that could potentially threaten transmission lines that serves communities in another part of the service area.

Potential consequences from O1B are summarized on an annualized basis in Table II-2. Safety impacts are associated with injuries or fatalities resulting from storms. Reliability impacts are associated with service interruptions caused by weather events. Financial costs are associated with repairing equipment or replacing and restoring equipment and assets after a weather event has occurred. For O1B, the estimate of annual impacts is 0.67 serious injuries, 0.08 fatalities, over 68.5 million CMI, and over $10.3 million in financial harm, on a mean basis.

Table II-2 – Outcome 1B (Increased Catastrophic Weather Events): Consequence Details[39]

Outcome 1B		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*	SCE reviewed the 7 largest wildfires in the past 12 years and observed 1 fatality to a utility worker, or 0.0833 fatalities/event. SCE applied a ratio of (8.3:1) based on the number of injuries and fatalities accounted for in the National Fire Protection Association's report on Fires by Occupancy or Property Type, which uses data from 2010 - 2014, to derive a serious injury value.	SCE reviewed the 7 largest wildfires in the past 12 years and observed 1 fatality to a utility worker. This translates to 0.0833 fatalities/event.	As an example for this outcome, SCE evaluated the impacts from extreme rain events on areas prone to landslides that contain transmission towers. SCE estimated that such extreme rain events to occur every 37.5 years, and could result in 453 million minutes of customer interruption on average.	SCE estimated the cost to restore power and provide backup generation to mitigate the impacts of the outcome. SCE estimated $18-20M dollars for contingency back-up generation.
Model Outputs	NU - Mean	0.67	0.08	68,507,788	$ 10,358,584
	NU - Tail Avg	3.65	0.79	399,964,690	$ 60,475,864

3. O2A – Higher Energy Procurement Cost

This outcome occurs when extreme heat contributes to higher energy procurement costs. Heatwaves are typically three or more consecutive days of extremely high temperatures.

[39] Please refer to WP Ch. 12, pp. 12.34 – 12.35 *(Baseline Risk Assessment Workpaper)*.

Historically, heatwaves occur between three to four times per year in SCE's service territory and result in peak electricity demand.

Electricity market costs during heatwaves are typically about four times higher than prices of electricity during non-heatwave summer days, although the load is only 1.3 times higher on average for heatwaves vs non-heatwave summer days. As an example, the total cost of electricity during heatwaves in 2017 (four events) was about $67M more as compared to what the costs would have been on average temperature summer days.[40]

The price of electricity is usually highest in the summer months due to customer demand, power plant availability,[41] and cost of fuel.[42] Other factors such as weather conditions and regulations also influence the price of electricity.[43] Additionally, heat increases the cost of operation and maintenance, for power plants and transmission and distributions systems,[44] and also increases line losses of electricity.[45]

Potential consequences from O2A are summarized on an annualized basis in Table II-3. Financial costs are associated with increased energy procurement costs during extreme heat events. For O2A, the estimate of annual impacts is nearly $30 million in financial harm, on a mean basis.

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[40] Please refer to WP Ch. 12, pp. 12.36 – 12.42 *(Heatwave vs. Average Summer Temperatures Workpaper)*.

[41] Costs to operate and maintain power plants vary based on the type, age and efficiency of the power plant.

[42] Fuel costs such as natural gas vary in correlation with demand. A higher demand increases the fuel cost and therefore increases the cost to generate electricity.

[43] Extreme temperatures can increase the demand for electricity, especially for cooling. Therefore, the price of electricity goes up in response to the demand. Significant strain is also placed on generators and transmission lines as they perform less efficiently. In addition, wildfires or the risk of wildfires can force transmission lines to be taken offline, and these situations impair the operation of the system.

[44] Transmission and distribution systems supply electricity and have associated maintenance cost and schedules, including repair and restoration of damaged components resulting from accidents or extreme weather events.

[45] Transformers, power lines and ancillary equipment will function at a lower efficiency due to line loss arising from higher temperature operating conditions. Line loss is energy waste resulting from the transmission of electrical energy across power lines; it can affect transmission and well as distribution lines. These losses occur due to the conversion of electricity to heat and electromagnetic energy. In hotter temperatures, line loss is more prominent.

Table II-3 – Outcome 2A (Higher Energy Procurement Cost): Consequence Details[46]

Outcome 2A		Consequences			
		Serious Injury	Fatality	Reliability	Financial
Model Inputs	*Data/sources used to inform model inputs*				SCE evaluated the differences in daily energy procurement costs during summer heat wave days vs non-heatwave summer days, over the 2015 2017 period.
Model Outputs	NU - Mean				$ 29,912,995
	NU - Tail Avg				$ 78,838,221

4. O2B – Exceptional Energy Procurement Cost

a. Description

As highlighted in Outcome 2A, there is a correlation between heatwaves and higher energy procurement costs. However, when this phenomenon is coupled with other compounding forces, such as volatile natural gas prices, the price of electricity can rise to unprecedented levels. For example, an instance occurred from July 24th – 25th, 2018 when the market reacted unfavorably to declarations by SoCalGas related to natural gas supply (Stage 4 alert on 7/23/18 and Low Inventory Operational Flow Order on 7/25/18).[47] As a result, natural gas prices soared from an average of $4/MMBTU to $39/MMBTU, driving up the market price of electricity by a similar order of magnitude. SCE has experienced one instance of exceptionally high procurement costs due to heat events and other compounding factors in 2018.[48] The cost to procure power during these events was approximately $200M higher than what otherwise would have been incurred given average summer temperatures and absent compounding impacts from other market forces.[49]

Potential consequences from O2B are summarized on an annualized basis in Table II-4. Financial costs are associated with energy procurement costs during extreme heat events coupled with other compounding forces, such as volatile natural gas prices. For O2B, the estimate of annual impacts is over $17 million in financial harm, on a mean basis.

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[46] Please refer to WP Ch. 12, pp. 12.34 – 12.35 *(Baseline Risk Assessment Workpaper)*.
[47] US Energy Information Administration – Published September 25, 2018, *available at* https://www.eia.gov/todayinenergy/detail.php?id=37112
[48] Year-to-date through 9/13/18.
[49] Please refer to WP Ch. 12, pp. 12.36 – 12.42 *(Heatwave vs. Average Summer Temperatures Workpaper)*.

Table II-4 – Outcome 2B (Exceptional Energy Procurement Cost): Consequence Details[50]

Outcome 2B		Consequences			
		Serious Injury	**Fatality**	**Reliability**	**Financial**
Model Inputs	*Data/sources used to inform model inputs*				SCE evaluated the differences in daily energy procurement costs during summer heat wave days vs non-heatwave summer days in 2018, when those days experienced compounding market forces that drove energy prices exceptionally higher than normal.
Model Outputs	NU - Mean				$ 17,675,855
	NU - Tail Avg				$ 141,132,954

[50] Please refer to WP Ch. 12, pp. 12.34 – 12.35 *(Baseline Risk Assessment Workpaper)*. Also note that while O2B is focused on exceptionally high procurement costs compared to procurement costs contemplated in O2A, the modeled financial consequences for O2B, as shown in Table II-4, are lower on an annual basis than O2A. This is due to the lower likelihood of occurrence of O2B. For example, in the last four years, O2B has only occurred once while O2A has occurred 12 times, and this ratio is reflected in the model outputs.

III. Compliance & Controls

SCE has programs and processes in place that address climate change impacts on SCE's business. These controls are summarized in Table III-1 and described in more detail below.

Table III-1 – Inventory of Compliance & Controls[51]

Controls		Risk Bowtie Impacts			2017 Recorded Capital ($M)	2017 Recorded Expense ($M)
ID	Name	Drivers	Outcomes	Consequences		
C1	Emergency Management	n/a	O1A, O1B	All	$0	$3.7
C2	Fire Management Program	n/a	O1A	All	$0	$0.5
C3	Climate Adaptation Community Grants (not modelled)	n/a	n/a	n/a	$0	$0.5

C: Control (Activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. SCE does risk-model controls in this report.)

A. C1 – Emergency Management

Emergency Management provides expertise and direct support for SCE's emergency management preparedness, response and recovery operations. The group's personnel build relationships with external emergency response partners, such as law enforcement, first responders, other utilities and city, county, state, and federal government agencies to enhance resiliency of SCE's operations and external collaboration during actual incidents. Emergency management includes training, exercising and activating one or more SCE Incident Management Teams (IMT)[52] / Incident Support Teams (IST),[53] and the Crisis Management Council (CMC).[54]

SCE coordinates drills and exercises for the IST/IMT and CMC in addition to an annual Full-Scale Exercise. That exercise includes external evaluators and emergency management counterparts from other utilities and government agencies.

SCE operates a 24/7 Watch Office that serves as a hub for Emergency Management. The Watch Office is the primary point of contact for SCE's various control centers (e.g., grid control, distribution operations control, telecommunications control, security operations, and more). It provides company-wide situational awareness (in collaboration with the co-located Situational

[51] Please refer to WP Ch. 12, pp. 12.43 – 12.52 *(RAMP Mitigation Reductions)*.
[52] An IMT is a team of trained personnel from across SCE who are brought together to coordinate within and across four functional areas of the Company (Electrical Services, Generation, Security & Facilities, and Information Technology) prior to and during an emergency event.
[53] An IST is a team of trained personnel similar to an IMT; however, the IST acts as a coordinating body to provide governance when there are multiple simultaneous incidents ongoing, such as multiple wildfires in different geographical regions of our service territory
[54] The CMC is a senior executive governance body responsible for providing strategic corporate-level policy making and direction related to emergency management. The CMC does not make incident-level or tactical decisions.

Awareness Center), reports on critical incidents, executes notifications, and manages IST/IMT activations.

SCE utilizes an Emergency Operations Center (EOC) to assemble IST/IMTs and help them collaborate when coordinating a corporate response to an incident. The EOC has modernized IT/Telecommunication equipment, and is co-located with the Watch Office and Situational Awareness Center to enable effective planning, communication and engagement with all stakeholders including field crews and external parties to efficiently coordinate restoration and recovery operations.

While the costs for this control are only represented within this Climate Change chapter, the Emergency Management control also supports our preparedness and response to other risks, including those presented in other RAMP risk chapters.

1. Outcomes & Consequences Impacted

a. O1A – Increased Major Weather Events and O1B – Increased Catastrophic Weather Events

Emergency management practices reduce the safety and reliability consequences of Outcomes 1A and 1B. Keeping our customers and our crews safe is our highest priority during major or catastrophic storm events. IMTs, field crews, and operators set objectives for safety, restoration, and other priorities before commencing work. Job hazard assessments are conducted and safety instructions are sent to the various teams and crews mobilized to restore service. Collectively, these actions refocus our work and our employees on safety and reduce safety-related consequences.

The coordinated approach to emergency management can reduce reliability consequences by utilizing emergency management plans developed in advance of the severe weather events (rain storms, heat storms, and wildfires) to maintain reliable performance of the system, including in situations where natural hazards can cause infrastructure damage. SCE response crews are often staged and ready to respond and restore equipment and service during storms and other incidents.

In addition, SCE proactively addresses emergent risks that may occur because of extreme weather-related events. For example, in 2015, the El Niño season threatened to cause major outages in Santa Barbara County if non-redundant infrastructure serving that geographic area were to experience significant weather-related damage. In response to this risk, SCE took proactive steps and provided for alternative generation in the event that power

delivery equipment experienced significant damage due to extreme rainfall and deep-seated landslides.

Financial consequences can be reduced or substantially avoided by effectively planning and executing mitigation strategies to moderate the impact of damage to SCE infrastructure. This in turn reduces "downstream" impacts to customers such as loss of service, productivity and revenue. For example, SCE coordinates with fire agencies to deploy tactics such as dropping flame retardants and cutting dozer lines to limit the spread of wildfires to critical infrastructure.

B. C2 – Fire Management Program

SCE maintains a Fire Management Team that includes fire management officers possessing experience as fire fighters and/or linemen. These fire management officers perform the following activities:

- Conduct training on electrical safety for first responders;
- Proactively monitor fire threats to SCE infrastructure, coordinate with SCE IMTs, and assist in restoration activities involving electrical assets;
- Coordinate planning and response operations with external agencies[55] and first responders;
- Monitor climate change impacts on hazardous fuel (grass, heavy brush, chaparral, etc.) build-up that increase the severity and duration of wildfire events; and
- Support project teams focus on hardening the grid to accommodate climate change drivers linked to wildfires.

Over the past few years, these efforts have become more integral to preparing for and responding to wildfires. Accordingly, SCE plans to hire one additional fire management officer and one fire scientist to support the increased focus on preventing and mitigating fires. These resources will support projects, programs and work streams focused on preparing for, responding to, and mitigating the impacts of wildfires. This includes supporting the development of complex fire models, which are designed to predict wildfire ignition and propagation by considering multiple variables such as weather, fuel, and asset conditions.

[55] External agencies that SCE coordinates with include: United States Forest Service, CAL FIRE, and County Fire Authorities.

1. Outcomes & Consequences Impacted

a. O1A – Increased Major Weather Events and O1B – Increased Catastrophic Weather Events

The actions of our Fire Management Programs will help reduce the severity and impact of major and catastrophic wildfires that may impact SCE assets and the communities we serve. These actions include disseminating red flag warnings[56] to prepare for fire weather conditions. Additionally, SCE fire management officers coordinate with state and federal agencies on tactical efforts such as dropping flame retardant and cutting fire breaks, as well as other measures to limit the spread of fires, help ensure safety, and protect critical transmission and distribution lines.

By identifying fires and monitoring fire behavior, SCE coordinates with agency representatives to limit and contain the spread of encroaching fires. By adding a fire scientist, SCE will be able to develop and mature its fire modeling capabilities.

Safety consequences can be reduced as a result of SCE conducting training sessions on electrical safety for first responders, issuing fire threat indications for SCE assets, and helping facility evacuations as necessary. Furthermore, Fire Management can assist in coordinating firefighting activities during an event to avoid contact with energized equipment and sidestep other potentially dangerous situations. Fire Management educates SCE personnel on tactics that the fire agencies use, so that efforts with the fire agencies are aligned and coordinated.

C. C3 – Climate Adaptation & Resiliency Community Grants

This control funds a diverse set of public and private stakeholders to support projects and programs that help disadvantaged communities adapt to climate change. The funding model focuses on collaborating and facilitating regional climate adaptation and resiliency.

Funded programs and projects include research, community-based education, environmental justice outreach, habitat restoration, disaster preparedness, species protection and environmental stewardship. SCE partners with local and regional government associations and efforts, such as the Los Angeles Regional Collaborative for Climate Action and Sustainability

[56] A red flag warning is prescribed by the National Weather Service based on critical fire weather conditions either occurring now, or will shortly. A combination of strong winds, low relative humidity, dry fuels and the possibility of dry lightning strikes can contribute to extreme fire behavior. Accessed September 26, 2013, http://www.fire.ca.gov/communications/communications_firesafety_redflagwarning

(LARC), so that alignment exists and effective and widespread implementation occurs. Because these grants are issued using shareholder funds, SCE does not model the effect of this control.

D. Additional Controls Discussed in Other Chapters

The Wildfire RAMP chapter contains one compliance control (CM1 – Vegetation Management) and one control (C2 – Ester Fluid (FR3) Overhead Distribution Transformer), which also provide benefits in the Climate Change arena. The quantitative modeling of the costs and benefits of these controls is provided in the Wildfire chapter. SCE qualitatively addresses how controls modeled in the Wildfire chapter likely provide benefits for climate change adaptation in this chapter. This qualitative approach was chosen because:

- It allows SCE to examine how Wildfire chapter controls and mitigations not only impact the 99th percentile extreme wildfires modeled in the Climate Change chapter, but also to look at potential benefits for the ongoing longer-term Climate Change Vulnerability Assessment (see Appendix 1). That longer-term assessment will examine wildfires associated with climate change and examine the impacts of increasing temperatures and heatwaves. This assessment may ultimately provide additional detail concerning mitigations that affect broader wildfire risks not associated with utilities.
- The magnitude of dollars that would be included if the Wildfire chapter controls and mitigation were quantitatively modeled would dwarf the existing portfolio of controls and mitigations contained in this chapter. For example, the costs associated with the controls and mitigations included in the climate change portfolio are approximately $13 million per year, while the wildfire mitigations total well over $100 million per year. Including the Wildfire chapter controls and mitigations could skew the existing portfolio results and potentially dilute the control/mitigation analysis currently included in the Climate Change chapter.
- The qualitative assessment approach can provide the base for potential further improvement and cross-chapter integration in future RAMP filings.

Table III-2 contains a summary of the controls included in the Wildfire chapter that could provide benefits for reducing climate change risk.

Table III-2 – Controls Included in Wildfire Chapter with Qualitative Climate Change Benefits

Wildfire Chapter Control	Control Description	Likely Benefits for Climate Change Chapter
CM1 – Vegetation Management	Vegetation management includes the expenses associated with tree pruning and tree removal in proximity to transmission and distribution high voltage lines, and weed abatement around selected overhead structures. It also includes costs to plant different species of trees as replacements and in handling preventive soil treatment. Besides SCE's normal vegetation management program, SCE also removes dead, dying, and diseased trees impacted by Bark Beetle or resulting from California's Drought Order.	• Tree pruning and removal could decrease risk to SCE's infrastructure from non-utility-associated wildfires (e.g., wildfires caused by lightning strikes, arson, etc.) • Removal of dead, dying and diseased trees will reduce the fuel available to spread wildfires. Removing these trees will also prevent them from catching fire due to causes other than utilities.
C2 – Ester Fluid (FR3) Overhead Distribution Transformer	Distribution line transformers insulated with mineral oil have a flashpoint of approximately 180°C while FR3 insulated transformers have a flashpoint closer to 360°C. This increased flashpoint means that new FR3 filled transformers can absorb more fault energy during an internal fault before failing catastrophically. This reduces the chance of igniting surrounding brush or other flammable material. Additionally, FR3 transformers have increased thermal loading capability which should improve summer heat storm performance, increasing the life expectancy of the transformers' insulation.	• As temperatures rise and the number and severity of extreme heat events increase, transformer capacity, efficiency, and resiliency are expected to decline. FR3 transformers can help mitigate these impacts through improved performance during summer heat storms.

IV. Mitigations

Besides the work that SCE has performed through 2017, SCE has identified methods to mitigate this risk. These activities are summarized in Table IV-1, and discussed in more detail thereafter.

Table IV-1 – Inventory of Mitigations[57, 58]

ID	Name	Driver(s) Impacted	Outcome(s) Impacted	Consequence(s) Impacted	Mitigation Plan		
					Prop.	Alt. #1	Alt. #2
M1	Climate Adaptation & Severe Weather Program		O1A, O1B	All	x	x	x
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	D3	All	All	x	x	
M2b	Situational Awareness, Monitoring & Analytics (Max)	D3	All	All			x
M3	Distribution System Stress Reduction Program		O1A	R		x	

M: Mitigation (Activity commencing in 2018 or later to affect this risk. SCE risk-models mitigations in this RAMP report.)

Consequence Abbreviations: Serious Injury – S-I; Fatality – S-F; Reliability – R; Financial - F

A. M1 – Climate Adaptation & Severe Weather Program Description

SCE formally implemented this program in 2018 and plans to continue this effort through the RAMP period as a long-term effort to centralize the Climate Adaptation and Severe Weather efforts across the Company. The program comprises SMEs from different organizational units (Transmission & Distribution, Generation, Corporate Real Estate, Business Resiliency, Information Technology, Policy & Community Engagement, and Strategic Planning), and external consultants in the climate change field. This program primarily seeks to better understand the impacts of climate change on our grid and facilities, and develop adaptation strategies to address climate impacts over time.

This program will identify the appropriate framework and criteria to assess and mitigate climate risks and coordinate the use of this framework company-wide. Specifically, the program seeks to:

- Modify business processes (e.g., energy procurement and demand forecasting, engineering and equipment procurement, customer service, power generation and delivery, and system design and planning) to enhance SCE's resilience to potential climate impacts;
- Develop an investment and programming strategy and implementation plan to address near-, medium-, and long-term impacts;
- Identify indicators to monitor over time to inform decision making;

[57] Please refer to WP Ch. 12, pp. 12.43 – 12.52 *(RAMP Mitigation Reductions)*.
[58] For M1, only impacts to O1A and O1B were modeled due to insufficient data to model the mitigation effectiveness on other outcomes.

- Harden assets and infrastructure (e.g., buildings, IT, electric and generation infrastructure) in response to potential climate impacts;
- Change engineering criteria and standards to modify to enhance asset and system resilience;
- Update maintenance practices (e.g. inspection schedules, and preemptive replacement approaches) to enhance asset and system resilience; and
- Advance SCE climate strategy through policy action and external engagement.

1. Outcomes & Consequences Impacted

a. O1A – Increased Major Weather Events and O1B – Increased Catastrophic Weather Events

Currently, the program performs analyses to inform seasonal weather outlooks and storm preparedness efforts. This enables proactive planning for potentially severe weather events. In other words, this mitigation can reduce the consequences associated with major and catastrophic weather events on our system.

In the future, all outcomes and consequences will be targeted and potentially impacted by this mitigation. The Climate Adaptation and Severe Weather Program is currently conducting vulnerability assessments that will inform the types of mitigation activities that will also address O2A (Higher Energy Procurement Costs) and O2B (Exceptional Energy Procurement Cost). Please see Appendix 1 for additional information.

B. M2a – Situational Awareness, Monitoring & Analytics (Optimal)

Situational awareness is critical to SCE's operational decision-making and service delivery. Situational awareness gives SCE visibility to critical system operations, weather conditions across the system at different degrees of granularity, and other externalities that affect the daily operation of the grid. SCE has historically maintained this capability by coordinating information, analytics, and monitoring through the use of a 24-hour a day "Watch Office" that receives and disseminates critical information across the Company.

The Situational Awareness Center (SA Center) is currently operated by three meteorologists who provide weather forecasts, analytics, and hazard advisories to support executing core business functions. SCE intends to add two additional meteorologists in the fourth quarter of 2018. These additional meteorologists will support increasing workloads in the SA Center and help build capabilities in wildfire mitigation. The SA Center also assists electricity demand forecasting and enhances the execution of work in the field. The SA Center is being equipped with advanced computer systems that simultaneously run several meteorology applications and integrate information collected from monitoring devices such as weather stations and HD

Cameras. This will increase our capacity to better forecast weather and climate-related events, and will help inform decision-making during regular operations and during incidents.

a. Weather Stations

Weather stations are pieces of equipment containing sensors that capture and transmit weather data, including wind speed, humidity, etc. This real-time weather information can be used to monitor weather and validate weather models.

SCE evaluated existing weather forecasting and assessment products and services offered by vendors, as alternatives to the deployment of this mitigation. However, the weather forecasting and assessment models available through these existing tools rely on limited reliable weather sensor data in high fire risk areas. To improve the accuracy and specificity of weather data to support operational decisions, there is a strong case for installing additional weather stations and HD cameras with specific circuit-level detail to provide more granular information that is not achievable through other off-the-shelf weather forecasting products and services.

SCE's pre-existing weather stations were installed over twenty years ago, and while still in use, lack the precision and capabilities of modern-day technologies. Furthermore, these legacy weather stations were deployed in substations and not on distribution lines in high fire risk areas. They do not directly support SCE's objective to forecast and assess high fire conditions that may warrant preemptive de-energization.

SCE intends to install additional weather stations on circuits in high fire risk areas, including up to a total of 125 stations by the end of 2018, and an additional 725 weather stations from 2019 – 2020. This results in a total network of about 850 weather stations throughout the SCE high fire risk areas. SCE has established a distribution overhead standard and installation guide, which is being used by distribution crews to install these units. Once we reach the desired level of deployment of 850 weather stations, SCE believes we will have improved granularity in weather data to more effectively forecast weather conditions at the circuit level and inform critical operational decisions during extreme weather events.

b. High Definition (HD) Cameras

Wildfires frequently start as smaller versions of brushfires before they grow and become catastrophic events. To minimize the growth and propagation of fires and help with fire suppression efforts, SCE is partnering with the University of California, San Diego (UCSD) to procure, install and maintain pan-tilt-zoom HD Cameras at up to 80 sites. These cameras can spot fires from a 100-mile radius and determine the size and approximate location

of the fire. SCE is targeting these cameras to provide up to 90 percent coverage of SCE's high fire risk area.

UCSD is serving as a technical, research, and execution partner for deploying the weather stations. SCE is working with the Orange County Fire Department (OCFD) on an initial roll-out, and will begin incorporating counties and fire agencies throughout SCE's high fire risk area to provide HD Camera live feeds. This information is critical to fire agencies for effectively deploying air and ground resources to limit and contain fires in the early stages.

c. Advanced Weather Modeling Tool

In addition to the integrated weather monitoring devices (weather stations and HD Cameras) mentioned above, SCE contracted with IBM, an international leader in weather modeling, to develop an advanced modeling tool. This tool will provide more frequent, higher-resolution forecast data on one comprehensive platform, including information gained from SCE's weather stations. The tool will provide higher-resolution forecast information down to 500m, and short-term forecast updates as frequently as every 15 minutes. This is faster than SCE's current models, which are mainly run on six- or twelve-hour cycles and at resolutions of 3km or greater. The model will forecast weather parameters such as temperature, wind speed and gusts, humidity, and precipitation. This system will provide these benefits:

- Enhanced resolution and more accurate forecast data to better inform deploying SCE's PSPS protocol;
- Severe weather forecasting including wind, thunderstorms, and heavy rain events along with extreme temperatures;
- Visualization of weather conditions and forecasts around SCE infrastructure; and
- Overall support to SCE's IMT in developing HFRA forecasts and fire response plans.

IBM has delivered an initial functional forecasting model and visualization tool. IBM is currently developing enhancements to the initial release of the software, and will add additional capabilities and features in future phased releases.

d. Advanced Modeling Computer Hardware

The advanced capabilities described above will require advanced computing power and speed to efficiently and reliably predict wildfire threats and other hazards. SCE will procure advanced computer hardware and deploy state-of-the-art software to run a sophisticated Fire Potential Index model. The model will account for various factors including

weather, live fuel moisture, and dead fuel moisture to assess the level of risk of wildfire ignitions. This platform will also enable software that analyzes decades of data for fuel and weather characteristics from past wildfire ignitions, and compares and contrasts those variables against current conditions to forecast the Fire Potential Index. The output from this model will be used to inform operational decisions, implement work restrictions, and optimize resource allocation for emergency situations. SCE is obtaining the hardware and software for its high-performance computing platform, and intends to begin using it in 2019.

1. Drivers Impacted

This mitigation will reduce effects of D3 – extreme wildfire events. If we can more quickly spot developing fires, we can enable faster responses to contain the fire. SCE is focused on accessing more detailed information about wildfire risk at the individual circuit level, to better understand how weather conditions might impact utility infrastructure and public safety in high fire risk areas. This plan includes contracting with IBM to access a high-resolution weather model and purchasing a high-performance computer platform that will aggregate complex data to generate geographically-based fire potential indices to approximate wildfire risk across SCE's service area.

Coupled with deploying additional weather stations and HD cameras, these new capabilities will better inform operational decisions, help SCE's emergency management staff determine how best to reduce potential wildfire risks, and make us even more effective at responding to fire events when they occur. Because technology is critical to this effort, and is always evolving, SCE is exploring the use of alternative technologies in parallel with utilizing the proven technology being used today. Our approach includes a program study to support a high-resolution weather forecast tool.

2. Outcomes & Consequences Impacted

a. O1A – Increased Major Weather Events and O1B – Increased Catastrophic Weather Events

Increased situational awareness will enable SCE to better forecast the impacts of extreme events on our generation, corporate real estate, and telecommunication assets as well as impacts on business processes. This mitigation will enable the Company to take early action (such as pre-staging of resources and activation incident management teams) to pre-plan our response. This lets us make quicker decisions regarding how and when to restore power when an extreme event occurs.

This mitigation may also improve response time, which in turn may reduce outage times. Greater awareness of emerging weather events will allow us to plan upfront and

appropriately modify work procedures to improve the safety of our workers and the communities we serve.

b. O2A – Higher Energy Procurement Cost and O2B – Exceptional Energy Procurement Cost

Highly accurate weather forecasts are critical in determining SCE's generation capacity on hot weather days. Accurate weather forecasts are also needed to accurately forecast load for day-ahead market transactions. An accurate weather and load forecast allows for a more informed assessment of financial risk. This assessment of financial risk helps determine hedging strategies as well as the potential need to purchase energy on the spot market.

Exceptionally high energy procurement cost incidents are difficult to predict,[59] so it becomes even more important to have quality weather and demand forecasts. Advanced weather modeling may foster greater integration of additional weather variables tailored to improve load forecast projections with more accurate and granular weather forecast information.

C. M2b – Situational Awareness, Monitoring & Analytics (2600 weather stations)

This mitigation includes all components of M2a, but adds additional weather stations to the scope. This mitigation would install 2,600 weather stations (two per circuit for each of the 1,300 circuits in HFRAs) in order to attain the higher limit considered for installation. However, SCE benchmarked with San Diego Gas and Electric (SDG&E) and obtained a ratio of 1:5 for weather stations to HFRA square miles. This ratio equates to 850 weather stations for the identified HFRAs.[60]

D. M3 – Distribution System Stress Reduction Program

SCE typically replaces distribution assets, such as transformers, when they fail in service, or when we observe deterioration during inspection or other fieldwork. Deterioration may include leaks, corrosion, and damage caused by vehicle collisions or acts of nature. Climate change-driven weather conditions, including extreme heat events, can make these assets more susceptible to breaking down earlier than expected. This mitigation would proactively replace

[59] These incidents can occur due to compounding factors that inflate price of electricity. One example is a natural gas shortage occurring during a heatwave.
[60] Please refer to WP Ch. 12, p. 12.53 *(Number of Weather Stations)*.

distribution transformers prior to failure. SCE would target this effort in disadvantaged communities (DACs) that may feel an exceptional burden or hardship due to an outage.

SCE's initial effort on this mitigation, while still conceptual, will focus on DACs, prioritizing proactively replacing overloaded or deteriorated equipment identified for future replacement at some point, but not yet addressed because of resource limitations. This work would target specific geographic locations believed to be climate-vulnerable using the California Environmental Protection Agency's ("CalEPA") definition.[61]

1. Outcomes & Consequences Impacted

a. O1A – Impacts from Major Weather Events

Reliability impacts to customers will be reduced by proactively replacing aging equipment before equipment failure occurs.

Climate hazards tend to have disproportionate impacts on disadvantaged communities. For example, those who may experience power outages in these communities may not have the resources to find alternative means to power medical equipment, or may have to endure extended periods of dealing with heat or cold as they may not have the ability to relocate temporarily. Given these circumstances, it is prudent to explore various mitigation strategies to offset the potential for weather-related outages in these communities.

E. Additional Mitigations Discussed in other Chapters

Similar to our discussion in Section III, there are two mitigations proposed in the Wildfire chapter that also likely provide some degree of benefit for this chapter. Table IV-2 contains a summary of these two proposed mitigations that are modeled in the Wildfire chapter but that also provide benefits for reducing climate change risks.

[61] CalEPA specifies disadvantaged communities (DACs) to be the 25% highest scoring census tracts in the state along with the 22 census tracts that score in the highest 5% of CalEnviroScreen's pollution burden, but which have no overall CalEnviroScreen score because of unreliable socioeconomic or health data. This definition is consistent with the use of the California Communities Environmental Health Screening Tool Version 3 ("CalEnviroScreen 3.0") in other Commission proceedings. CalEnviroScreen scores are based on pollution burden and population characteristic indicators. Other tools such as California's Healthy Places Index may also help identify target areas.

Table IV-2 – Mitigations Proposed in Wildfire Chapter that have Benefits to Climate Change Chapter

Wildfire Chapter Mitigation	Mitigation Description	Likely Benefits for Climate Change Chapter
M5 – Expanded Vegetation Management	SCE plans to expand its vegetation management activities to assess the structural condition of trees in HFRA that are not dead or dying, but could fall into or otherwise impact electrical facilities. These trees may be as far as 200 feet away from SCE's electrical facilities. Trees posing a potential risk to electrical facilities due to their structural or site condition will be removed or otherwise mitigated. SCE views this as an important effort in light of increasing winds that have the potential to blow debris into utility lines from even greater distances.	Tree pruning and removal as far as 200 feet away from SCE's electrical facilities can help reduce the amount of fuel near SCE's infrastructure.
M9 – Fire Resistant Poles	At locations where SCE is installing covered conductor in HFRA and pole replacements are required, SCE will use fire-resistant composite poles, where appropriate, instead of traditional wood poles. These poles are specifically designed to withstand wildfires, which will harden the distribution system.	The installation of fire-resistant composite poles could decrease risk to SCE's infrastructure from non-utility-associated wildfires (e.g., wildfires caused by lightning strikes, arson, etc.).

V. Proposed Plan

SCE has evaluated each control and mitigation listed in Section III and IV and has developed a Proposed Plan to address this near-term risk, as shown in Table V-1 below.

Table V-1 - Proposed Plan (2018 – 2023 Total Costs and Risk Reduction)

Proposed Plan		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Emergency Management	2018	2023	$0.0	$21.3	2.24	0.10	7.46	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.02	0.22	1.99	0.42
M1	Climate Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.81	0.33	2.65	1.08
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	2018	2023	$26.8	$28.0	2.25	0.04	6.08	0.11
			Total - Proposed Plan	**$26.8**	**$56.4**	**6.32**	**0.08**	**18.18**	**0.22**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend)

A. Overview

The Proposed Plan combines existing controls and new mitigations that will reduce the impacts of severe weather and climate change on our system. On an annualized basis and using mean results, the Proposed Plan would reduce potential serious injuries down to approximately one per year; reduce potential fatalities by nearly half to a number close to zero per year; reduce CMI by approximately 28 million per year; and reduce financial consequences by approximately $45 million per year.

B. Execution Feasibility

SCE believes it can continue to execute the existing controls in this plan (C1 – Emergency Management and C2 – Fire Management Program). We have performed these activities for years, and we have proven processes and capabilities. SCE does not see substantial constraints in being able to execute on the Proposed Plan's new mitigations. Specifically, SCE has determined the optimal number of weather stations to deploy as part of M2a – Situational Awareness. SCE evaluated the pace of deploying the new equipment in M2a against the resources available to deploy it, and found this level and pace of deployment is feasible. In addition, SCE has already deployed over 100 of these weather stations this year. SCE is utilizing vendors that have worked on similar projects to install weather stations and HD Cameras for other California IOUs to help ensure successful deployment and service.

SCE evaluated the technical constraints of deploying this plan. For example, specific requirements for installing weather stations could restrict the volume of stations deployed, including:

- Access to facilities, right-of-way condition, road conditions;
- Public lands sensitivity (e.g. National Forest);
- Acceptable cell coverage for transmitting weather data;
- Poles should ideally be accessible by bucket truck without impacting traffic;
- The weather stations must be mounted at least 20 feet above the ground;
- Poles should have a clear view of southern sky; and
- Presence of equipment on pole that would prevent a weather station from being safely installed.

Based on SCE's evaluation, these requirements pose no issue in deploying the Proposed Plan.

C. Affordability

The Proposed Plan is the least-cost option and has the highest RSE compared to the alternative plans (Proposed RSE = 0.08; Alternative #1 RSE = 0.06; and Alternative #2 RSE = 0.05). Based on these results, the Proposed Plan provides greater value to our customers and for our operations compared to the alternative plans.

VI. Alternative Plan #1

SCE evaluated other options to address this risk and developed an alternative plan as shown in Table VI-1.

Table VI-1 – Alternative Plan #1 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan #1		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Emergency Management	2018	2023	$0.0	$21.3	2.23	0.10	7.44	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.01	0.22	1.98	0.42
M1	Climate Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.81	0.33	2.64	1.08
M2a	Situational Awareness, Monitoring & Analytics (Optimal)	2018	2023	$26.8	$28.0	2.25	0.04	6.07	0.11
M3	Distribution System Stress Reduction Program	2018	2023	$25.0	$0.0	0.08	0.00	0.17	0.01
			Total - Alternative Plan #1	**$51.8**	**$56.4**	**6.38**	**0.06**	**18.30**	**0.17**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend)

A. Overview

Alternative Plan #1 contains all the same controls and mitigations included in the Proposed Plan, but includes one additional mitigation M3 (Distribution System Stress Reduction Program). As discussed in Section IV, this mitigation focuses on proactively replacing equipment that may be susceptible to overloading in hot weather conditions. Proactively replacing this equipment potentially provides direct reliability benefits, and consequently may provide relief to individuals who lack alternative means to deal with power outages. This mitigation would replace 200 distribution transformers annually to reduce the customer minutes of interruption experienced when an overloaded transformer breaks down.

SCE believes that a proactive replacement program targeted in climate-vulnerable DACs could be a viable future mitigation. However, at this time, this mitigation is still at the conceptual design phase. SCE must perform further engineering studies and work management efforts before this mitigation is ready to be broadly deployed. We will continue to carefully evaluate this program for future consideration.

Alternative Plan #1 achieves approximately the same safety, reliability and financial consequence reductions as the Proposed Plan. But it does so at a higher cost.

B. Execution Feasibility

In discussing the Proposed Plan, we explain the execution feasibility of the first four activities in this plan (C1, C2, M1, and M2a). The conceptual mitigation M3 (Distribution Stress Reduction Program) requires further validation through additional studies to determine the

appropriate scope of work and to identify the appropriate areas of our service territory where this would be deployed. SCE must also gain a better understanding of the resource requirements for executing this work, and balance the need for the work against other high priority grid-related work.

C. Affordability

The cost of Alternative Plan #1 is approximately 30% more than the Proposed Plan. This increased cost does not come with a commensurate increase in risk reduction. As a result, the RSE of this plan is substantially lower than the Proposed Plan (0.06 vs 0.08, respectively).

D. Other Considerations

This plan would involve outage coordination constraints involved with proactively replacing distribution transformers to help minimize service reliability impacts to customers.

VII. Alternative Plan #2

The third option that SCE evaluated is Alternative Plan #2, as shown in Table VII-1.

Table VII-1 – Alternative Plan 2 (2018 – 2023 Total Costs and Risk Reduction)

Alternative Plan #2		RAMP Period Implementation		Cost Estimates ($M)		Expected Value (MARS)		Tail Average (MARS)	
ID	Name	Start Date	End Date	Capital	O&M	MRR	RSE	MRR	RSE
C1	Emergency Management	2018	2023	$0.0	$21.3	2.21	0.10	7.36	0.35
C2	Fire Management Program	2018	2023	$0.0	$4.7	1.01	0.22	1.98	0.42
M1	Climate Adaptation & Severe Weather Program	2018	2023	$0.0	$2.4	0.80	0.33	2.62	1.07
M2b	Situational Awareness, Monitoring & Analytics (Max)	2018	2023	$56.8	$35.9	2.59	0.03	7.44	0.08
			Total - Alternative Plan #2	**$56.8**	**$64.3**	**6.61**	**0.05**	**19.39**	**0.16**

MRR = Mitigation Risk Reduction
MARS = Multi-Attribute Risk Score
RSE = Risk Spend Efficiency (risk units reduced per $1M spend)

A. Overview

Alternative Plan #2 includes the same controls and one of the same mitigations (M1 – Climate Adaptation & Severe Weather Program) as the Proposed Plan. However, Alternative Plan #2 replaces M2a (Situational Awareness, Monitoring & Analytics – Optimal) with M2b (Situational Awareness, Monitoring & Analytics – Max).

M2b proposes deploying 2,600 weather stations instead of the 850 weather stations deployed in M2a. This level of deployment would place two weather stations on each of the 1,300 identified circuits in SCE high fire risk areas.

While this level of deployment would provide much more granularity than M2a, a cross-functional project team (meteorologists, grid operations, and distribution system personnel) determined that 850 weather stations will be sufficient to provide high resolution weather data after benchmarking with SDG&E to evaluate the ratio of weather stations to HFRA square miles.[62]

B. Execution Feasibility

Compared to the Proposed Plan, Alternative Plan #2 will require more resources to install the increased number of weather stations. The weather station count is about three times as many as in the Proposed Plan. To deploy this volume of weather stations, SCE would likely have to de-prioritize other work to accommodate resource constraints.

[62] Please refer to WP Ch. 12, p. 12.53 *(Number of Weather Stations)*.

C. Affordability

Alternative Plan #2 achieves approximately the same reductions to safety, reliability and financial consequences as the Proposed Plan. However, the cost of Alternative Plan #2 is approximately 43% higher. As a result, the RSE of Alternative Plan #2 is significantly lower than the Proposed Plan's RSE (Alternative #2 RSE = 0.05; Proposed RSE = 0.08; and Alternative #1 RSE = 0.06).

The increased costs are due to installing the additional 1,750 weather stations compared to the Proposed Plan. The level of deploying weather stations in the Proposed Plan is adequate to begin with. The Proposed Plan leaves open the option to deploy additional weather stations if future analysis and circumstances indicate that incremental value would be achieved by doing so.

D. Other Considerations

The quantity of weather stations contemplated in this plan may be above the optimal number of weather stations needed to make critical operational decisions. SCE will assess the need for additional weather stations in the coming years as it deploys the level of weather stations prescribed in the Proposed Plan.

VIII. Lessons Learned, Data Collection, & Performance Metrics

A. Lessons Learned

1. Future risks analyses should address all climate change impacts

In this immediate RAMP analysis, we could only model the event-based climate drivers using RAMP risk model. By not analyzing the full suite of climate threats posed to the Company in the near-term, we could not present and evaluate the full risk to our business from a changing climate in the quantitative RAMP risk analysis. We also could not evaluate the full risk reduction benefits and RSE of the controls and mitigations contemplated in this report, as the RAMP model only captured impacts from 2018-2023. SCE expects to learn and to expand our capabilities to more fully capture all climate change risks in future modeling efforts. SCE intends that its 2021 GRC incorporate the results of the Climate Change Vulnerability and Impact Assessment presented in Appendix 1.

2. Uncertainty in driver quantification

Due to natural variability and randomness in climate systems, there can be substantial uncertainty in developing climate driver projections for the near term (i.e., 0 to 10 years from present).[63,64,65] As a result, it is important to classify the climate driver projections used in the RAMP model as directional and subject to change.

B. Data Collection & Availability

The data used to derive inputs to the RAMP model were founded on academic research, SCE data, and input from internal and external climatologists, meteorologists, and other experts.[66] However, SCE understands that the climate adaptation space is rapidly evolving, and there is ongoing discussion around the data that should be used to evaluate and model the

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[63] Strategic Environmental Research and Development Program (SERDP) (2016) Climate-Sensitive Decision-Making in the Department of Defense: Synthesis of Ongoing Research and Current Recommendations. US Department of Defense.

[64] Walsh, J; Wuebbles, D; Hayhoe, K; Kossin, J; Kunkel, K; Stephens, G; Thorne, P; Vose, R; Wehner, M; Willis, J; Anderson, D; Kharin, V; Knutson, T; Landerer, F; Lenton, T; Kennedy, J; Somerville, R (2014) Appendix 3: Climate Science Supplement. Climate Change Impacts in the United States: The Third National Climate Assessment, Melillo, JM; Richmond, TC; Yohe, GW; Eds., U.S. Global Change Research Program, 735-789. doi:10.7930/J0KS6PHH.

[65] Flato, G; Marotzke, J; Abiodun, B; Braconnot, P; Chou, SC; Collins, W; Cox, P; Driouech, F; Emori, S; Eyring, V; Forest, C; Gleckler, P; Guilyardi, E; Jakob, C; Kattsov, V; Reason, C; Rummukainen, M (2013) Evaluation of Climate Models. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[66] Please refer to WP Ch. 12, p. 12.54 *(Subject Matter Expert Qualifications)*.

impacts of climate change. SCE has used the best reasonably-available data and information to develop this RAMP risk chapter, and we intend to fully support the climate adaptation community in further developing the breadth and depth of data to improve and refine future climate change analyses.

C. Performance Metrics

Many of the mitigations proposed in this RAMP report are brand-new to the Company and performance metrics to assess their effectiveness are not yet available. SCE will be developing metrics as part of the Climate Adaptation and Severe Weather Program's work during the next few years. Metrics that SCE will likely consider include:

- Number of times SCE HD Cameras identify fires first, or are used by fire agencies to identify and assess fire size, deploy resources and determine containment techniques.
- Metrics around using advanced modeling capabilities to provide advanced preparation and staging of resources ahead of major storm events.

Appendix 1

Near-, Medium-, and Long-term (2018 – 2050) Climate Change Vulnerability and Impact Assessment

IX. Appendix 1 – Near-, Medium-, and Long-term Climate Change Vulnerability and Impact Assessment

A. Introduction

This section describes the Climate Change Vulnerability and Impact Assessment that SCE is currently conducting to identify comprehensive priority climate impacts, develop climate projections for the 2018-2023, 2030, and 2050 time horizons, and produce an actionable adaptation plan to mitigate the potential climate change impacts facing SCE. The first draft of the Climate Change Vulnerability and Impact Assessment report will be developed by December of 2018. The report will help refine the Proposed Plan described in Section V, by including additional mitigations as applicable that address the more gradual impacts of climate change that should also be considered over the RAMP period.[67]

The following sections describe the process of this vulnerability and impact assessment, and the findings to date. This includes:

- The Climate Change Vulnerability and Impact Assessment framework;
- Potential climate impacts to SCE's assets and business processes; and,
- The approach for implementing adaptation measures over time.

B. Climate Change Vulnerability and Impact Assessment Framework

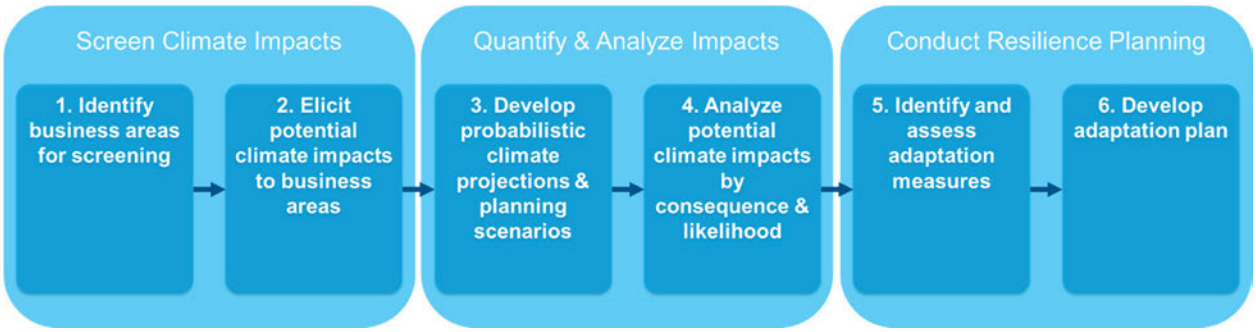
The framework to analyze potential near-, medium-, and long-term (2018-2023, 2030, and 2050) climate takes a decision-first approach.[68] The analysis is designed to identify and quantify potential impacts, and then produce an actionable adaptation plan that sets forth a portfolio of climate change adaptation mitigation measures.

The framework begins with interviewing internal experts to identify potential climate impacts facing SCE, as well as reviewing the established literature to capture all potential impacts. SCE then built climate projections that draw on best available climate science for climate variables that drive the impacts. The impacts are then assessed based on the projected magnitude of change in the variables. These outputs are used to inform adaptation planning, and help craft a suite of adaptation measures that are designed to mitigate impacts. Figure IX-1 below depicts this framework.

[67] The results of this report may influence the portfolio of mitigations that we submit as part of SCE's 2021 GRC.

[68] A decision-first approach is one that focuses on developing products to inform and improve decisions.

Figure IX-1 – Long-term (2030 and 2050) climate change vulnerability and impact assessment framework



1. Screen Climate Impacts

As summarized above, the climate change vulnerability and impact analysis begins with a rapid screening of the potential climate impacts relevant to SCE. The screening relies heavily on SME input and readily-available data to efficiently identify the key areas of SCE's business that may be impacted by a changing climate. The interviews were supplemented by reviewing literature to help ensure that known impacts that may not have been captured within the SME interviews were incorporated into the screening. The screening explored all aspects of SCE's business, and led to prioritizing potential impacts to be further considered and analyzed.

For each of the relevant aspects of SCE's business (i.e., assets, operations, demand forecasting, planning, grid modernization, and community engagement programs), SCE SMEs provided input into the climate impacts of greatest concern and how climate hazards affect assets and infrastructure, business processes, and externally-facing programs. Using a questionnaire and a series of semi-structured interviews, SCE documented the key climate hazards and variables that are important to each business area.

2. Quantify and Analyze Impacts

Based on the information gathered through the screening of climate impacts, SCE will analyze the impacts. We will quantify the impact wherever possible.

Notably, the methodology for developing future climate driver values differs between the near-term (2018 – 2023) and the medium- and long-term (2030 and 2050) components of this vulnerability and impact assessment. When developing predictions for conditions fewer than five years in the future, it is less beneficial to use climate models, whereas in the longer term (10+ years out), climate modeling is more appropriate. As a result, the near-term component of the vulnerability and impact assessment will draw upon academic literature and best available science for generating predictions for five-year time horizons.

Meanwhile, in the 2030 and 2050 time horizon analysis, SCE will use probabilistic climate projections for climate hazards where scientific support exists for doing so. Examples are changes in sea level, temperatures, and precipitation. In addition, for climate hazards without probabilistic climate information, SCE will develop projections of change in the variable or will use literature to provide information on expected trends. For priority cascading and compounding hazards, SCE will develop a set of high-impact planning scenarios to inform adaptation needs.

For the 2030 and 2050 time horizon analyses, SCE will rely on climate model information, primarily sourced from Localized Constructed Analogs data available via Cal-Adapt and released through California's Fourth Climate Change Assessment. This climate data will be processed to produce probabilistic climate projections that provide information on expected change and help assess impacts. The climate model information captures change in key climate variables due to greenhouse gas-caused warming, which becomes a more significant factor over time.

SCE will also conduct more in-depth analyses to characterize potential impacts by combining climate information with information about SCE's assets, operations, and planning processes. For instance, SCE plans to overlay maps of extreme heat projections with maps of customer demographic factors that exacerbate sensitivity to extreme heat impacts (e.g., age, income levels). In this way, we can identify areas that are particularly vulnerable and might require additional customer programs. Similar analyses will be conducted based on SME input on the type of analysis that can best inform adaptation needs and next steps.

The impact assessment will score impacts by level of consequence using SCE's impact matrix, which is based on likelihood and magnitude. The impacts will be weighted by impact type (e.g., financial, safety, reliability) and impact distribution (e.g., disadvantaged communities). SCE will then use workshops with SMEs to validate and refine consequence scores and identify any broader implications. The workshops will also help identify existing and potential adaptation measures.

3. Conduct Adaptation Planning

SCE will use the vulnerability and impact assessment results to inform adaptation planning. This includes identifying potential adaptation measures and developing an actionable adaptation plan.

Building on the findings of the workshops, SCE will identify preliminary descriptions of incremental and transformational adaptation measures at a conceptual level. These measures will be designed to address impacts across SCE's assets, operations, planning, grid modernization, and community engagement activities. Measures may address acute needs,

such as changes to emergency management protocols, or more general needs, such as establishing a process for changing design standards to incorporate future climate conditions. The measures may also include ways SCE can build capabilities across its lines of business to better manage impacts from climate change and extreme weather. The measures will be evaluated based on a variety of elements, such as feasibility, flexibility, effectiveness for multiple hazards, synergies across impact areas, and cost.

C. Priority Climate Impacts to SCE's Assets and Business Processes

Several climate hazards can potentially harm SCE's assets and business processes by 2018-2023, 2030, and 2050. These hazards include temperature, extreme precipitation, drought and snowpack, wildfires, and sea level rise and coastal flooding. The impacts these hazards pose to the safety, reliability, and affordability of SCE's electricity are described below; these were identified through reviewing applicable literature and interviewing SCE SMEs. These impacts align with those included in SCE's response to the CPUC Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation. This section provides a general overview of projected changes in key climate conditions. More detailed climate information will be developed to support the impact analysis, as required.

In addition to specific standalone hazard impacts, we see compounding issues in various locations in SCE's service territory, which must be further evaluated.

1. Average & Extreme Temperatures

Average temperatures are projected to increase, and heat waves are projected to become more intense and more frequent.[69] Existing scientific literature and State data sources (i.e., Cal-Adapt) provide information that indicates expected changes in temperature in the SCE territory.

Increased average temperatures, and particularly increased extreme heat, have the potential to increase stress on SCE's system, as described in Table IX-1, below. Notably, these are examples rather than a comprehensive list. Additionally, changes in non-climate parameters, such as the spatial distribution of population growth, can potentially influence which parts of SCE's system experience the greatest impacts.

[69] California Natural Resources Agency. 2018. Safeguarding California Plan: 2018 Update, *available at* http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf

Table IX-1 – Potential increased temperature impacts to SCE's system

Business Line Affected	Potential impact
Information Technology & Telecommunications	Increased air conditioning costs in telecommunication buildings
Transmission & Distribution	Reduced substation & transformer capacity and efficiency
	Overhead conductor, connector, and hardware failure
	Reduced efficiency of T&D lines
	Increased line sag
	Inverters disconnecting from grid
Generation: Thermal	Reduced generation capacity and efficiency
Generation: Hydropower	Reduced generation capacity and efficiency
	Increased evaporation of water within conveyance systems and reservoirs
	Increased likelihood of exceedance of outflow temperature limits
Generation: Wind	Reduced output
Generation: Solar Photovoltaic	Reduced generation capacity and efficiency

2. Average & Extreme Precipitation, Wind, Storms, Snowpack; Severity of Drought

The extreme precipitation events are projected to slightly increase in frequency and intensity in the medium and long-term due to climate change.[70] These changes are projected to affect SCE's infrastructure and operations in a variety of ways. Examples of the potential impacts are described in Table IX-2, below.

SCE's internal analysis projects a dramatic rise in January precipitation (+ 151 mm per month and runoff +23 mm per month) at some of our hydropower facilities between now and mid-century. The impacts on hydropower generation require additional study, because specific data points fail to represent the cumulative watershed impacts of this data set. SCE will engage in this analysis in the future.

Notably, longer-term extreme precipitation projections differ from the more near-term RAMP extreme precipitation driver (D1), which is expected to decrease slightly. This discrepancy may be because historical trends in the annual number of 99th percentile extreme rain events may not be a useful proxy for representing longer-term trends in extreme precipitation. Climate change models currently are not designed for modeling near-term climate.

[70] Swain, D. L., Langenbrunner, B., Neelin, J. D., & Hall, A. 2018. Increasing precipitation volatility in twenty-first-century California. Nature Climate Change, 8(5), 427.

Table IX-2 – Potential extreme precipitation, wind, & storm impacts to SCE's system

Business Line Affected	**Potential impact**
All Infrastructure	Increased flooding leading to damage of electrical equipment
	Increased flooding leading to damage to infrastructure from debris carried by floodwaters
	Inundation of access roads, inhibiting site access
	Debris flow
Information Technology & Telecommunications	Scouring and potential toppling of telecommunication poles
	Inundation of buildings, including data centers, leading to limited use and potential damage to equipment inside of buildings
	Communication failure due to flooding of splice cases and vaults
Transmission & Distribution	Scouring and potential toppling of T&D poles and towers
	Inundation of and damage to substation equipment, should flooding exceed 100-year flood levels, the standard to which substations are designed
	Lightning has the potential to damage assets
	Damage from extreme winds; lines are designed to 100-year wind speeds
Generation: Hydropower	Overflow of conveyance systems
	Depending on magnitude of precipitation and reservoir capacity and design, flooding can increase generation and replenish reservoirs, or result in excess spilling of water
	Increased flooding of surrounding communities
	Turbine damage from increased sedimentation and siltation
Workforce	Inundation limiting the ability of employees to travel to and from work

In California, climate change is projected to lead to more intense and frequent droughts, and reduced snowpack.[71] This is primarily expected to impact generation resources, as described in Table IX-3 below. Notably, these are examples rather than a comprehensive list.

[71] California Natural Resources Agency. 2018. Safeguarding California Plan: 2018 Update, *available at* http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf

Table IX-3 – Potential snowpack, drought, and average precipitation impacts to SCE's system

Business Line Affected	Potential impact
Transmission & Distribution	Increased potential for subsidence, potentially leading to reduced stability of transmission and distribution infrastructure
Generation: Thermal	Reduced cooling water availability
Generation: Hydropower	Reduced water available for generation, resulting in reduced generation capacity
	Lower reservoir water levels leading to cavitation of runners and damage to blades
Catalina	Water supply shortage

3. Frequency and Severity of Wildfire

Wildfires are projected to increase in frequency and severity under climate change.[72] Potential wildfire-related impacts to SCE's system are described in Table IX-4 – Potential wildfire impacts to SCE's system. Notably, these are examples rather than a comprehensive list. Additionally, future changes in wildfire are impacted by non-climate variables, such as urbanization, de-urbanization, and changes in the urban-wildland interface.

Table IX-4 – Potential wildfire impacts to SCE's system

Business Line Affected	Potential Impact
All Infrastructure	Equipment damage and failure
	Limited site accessibility
Workforce	Limited ability of employees to safely access infrastructure, exacerbating repair and recovery times

4. Sea Level Rise, Wave Run-up, & Coastal Flooding

Sea levels are projected to increase at an accelerating pace, leading to increased coastal inundation.[73] Potential impacts from sea level rise are described in Table IX-5 below. This table represents examples rather than a comprehensive list.

[72] California Natural Resources Agency. 2018. Safeguarding California Plan: 2018 Update, *available at* http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf
[73] *Id.*

Table IX-5 – Potential sea level rise, wave run-up, and coastal inundation impacts to SCE's system

Business Line Affected	Potential impact
All Infrastructure	Increased flooding leading to damage of electrical equipment
	Increased flooding leading to damage to infrastructure from debris carried by floodwaters
	Inundation of access roads, inhibiting site access
	Saltwater intrusion leading to inundation and corrosion of coastal infrastructure lacking corrosion protection
Information Technology & Telecommunications	Scouring and potential toppling of telecommunication poles
	Inundation of buildings, including data centers, leading to limited use and potential damage to equipment inside of buildings
	Communication failure due to flooding of splice cases and vaults
Transmission & Distribution	Scouring and potential toppling of T&D poles and towers
	Inundation of and damage to substation equipment, should flooding exceed 100-year flood levels, the standard to which substations are designed
Catalina	Saltwater intrusion into water supply wells
Workforce	Inundation limiting the ability of employees to travel to and from work

5. Soil Stability & Ecology (Landslides, Mudslides Subsidence, Vegetation, and other Ecological Variables)

Changes in soil stability and ecology also have the potential to impact SCE's level of vulnerability. For instance, increases in extreme rainfall have the potential to drive increases in landslides and mudslides. Additionally, increasing drought may lead to greater groundwater consumption, resulting in subsidence. The impacts identified in the table below are examples rather than a comprehensive list.

Table IX-6 – Potential soil stability and ecology impacts to SCE's system

Business Line Affected	Potential impact
All Assets	Landslides and mudslides can lead to equipment destabilization and damage
	Subsidence can damage underground assets
	Shifts in vegetation can enhance or reduce wildfire risk
Information Technology & Telecommunications	Towers and overland pipelines can be affected if footings are within subsidence zones
Generation: Hydropower	Damage to canals or to supports and/or footings of penstocks or flumes within subsidence zones
Transmission & Distribution	Towers and overland pipelines can be affected if footings are within subsidence zones

D. Approach for Implementing Measures over Time

SCE is developing a flexible adaptation pathway approach[74] for investing in adaptation measures over time, so that we account for the uncertainty in future climate information. A flexible adaptation pathway approach helps manage future uncertainty by allowing decision-making to adjust based on new information or conditions (e.g., new technologies, customer needs, climate conditions, and economic and policy landscape). The flexible adaptation pathways approach has been adopted in other climate adaptation contexts, including for the City of New York and for a major infrastructure project along the Thames River in England.

The approach will support flexible implementation over time, taking advantage of new information as it becomes available that may reduce uncertainty or provide a "signpost" of how conditions are changing. Using this flexible approach, adaptation measures can be sequenced over time to protect against near-term changes, while leaving options open to protect against a range of plausible climate futures later in the century.

For example, SCE may select a pathway, beginning in 2020, to implement additional tide gauges to more closely monitor rising sea levels. Sea level might be selected as a signpost to track changes in conditions. Then, a trigger of four feet of sea level rise could be selected to trigger an adaptation pathway that physically protects infrastructure against inundation. The adaptation pathway might involve raising the height at which equipment sits.

[74] Hasnoot, M., Kwakkel, J.H., Walter, W.E., & ter Maat, J. (2013). Dynamic adaptive policy pathways: A method for crafting robust decisions for a deeply uncertain world. Global Environmental Change, 23(2), 485 – 498.

E. Conclusions

SCE is in the process of completing its comprehensive near-, medium-, and long-term Climate Change Vulnerability and Impact Assessment for the 2018-2023, 2030, and 2050 time periods. Because established results are not yet available to incorporate into this RAMP report, SCE will likely update its proposed climate change mitigation portfolio in its 2021 GRC submission with the results.

Early assessment findings indicate that increases in extreme heat waves are among the hazards of greatest concern, because such increases impact SCE's power generation, delivery, and demand in a variety of ways that may cumulatively reduce SCE's ability to meet customer needs. Our analysis has identified compounding and cascading impacts that arise from hazards as a substantial concern. We will continue to explore these areas to better prepare for and adapt to the changing climate.

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Appendix A
Nuclear Decommissioning

Rosemead, CA
November 15, 2018

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I. BACKGROUND

In accordance with the request made by the Commission's Safety and Enforcement Division (SED), this appendix addresses the safety risks associated with the decommissioning of Southern California Edison's (SCE) San Onofre Nuclear Generating Station (SONGS).[1] As discussed below, SCE mitigates these safety risks by adhering to Nuclear Regulatory Commission (NRC) radiological safety regulations and other federal and state industrial safety regulatory agency requirements.

A. SONGS Location

SONGS is a three-unit nuclear generation facility located on the coast of southern California, in San Diego County, about 62 miles southeast of Los Angeles and 51 miles northwest of San Diego. The on-shore SONGS site is located within the boundaries of Marine Corps Base Camp Pendleton under easements granted by the U.S. Department of the Navy (Navy). The offshore sites, used for seawater intake and discharge conduits related to facility operations, are used pursuant to lease contracts with the California State Lands Commission (CSLC).

B. Shutdown Date

Unit 1 commenced commercial operations in 1968 and was permanently retired in 1992. Most of the onshore Unit 1 facilities were dismantled by 2009. The Unit 1 offshore conduits were partially dispositioned in 2014. All Unit 1 spent fuel was transferred from wet storage in the spent fuel pools to dry storage[2] in the on-site Independent Spent Fuel Storage Installation (ISFSI) during 2003-2005. The remaining Unit 1 structures are planned to be dispositioned concurrently with the decommissioning of Units 2 and 3.

Units 2 and 3 commenced commercial operations in 1983 and 1984, respectively, and were permanently retired in 2013. A portion of the Units 2 and 3 spent fuel was transferred from the spent fuel pools to the ISFSI during 2007-2012.[3] SCE now holds an NRC license that prohibits power operations, but authorizes the possession of the SONGS facilities and licensed nuclear material (spent fuel).

[1] During one of SCE's initial pre-filing RAMP meetings with SED, SCE was requested to provide a qualitative assessment of the safety risks associated with the decommissioning of SONGS.
[2] After fuel has been used in a reactor, it is stored in pools that utilize active filtration and cooling systems. After a period of cooling, it can be moved to onsite dry storage, which does not rely on active operational systems. See Section IV of this appendix for additional details.
[3] From 1983-2007, all fuel from Units 2 and 3 was stored in the spent fuel pools.

SCE is currently planning the decontamination and dismantlement of SONGS. All remaining Units 2 and 3 spent fuel is scheduled to be transferred from the spent fuel pools to the ISFSI.

C. Decommissioning Governance

SCE is the majority owner of SONGS. San Diego Gas & Electric Company (SDG&E), and the City of Anaheim and the City of Riverside (the Cities), are minority participants in the ownership and/or decommissioning liability of SONGS. SCE, SDG&E, and the Cities are collectively referred to as the Participants.

On April 23, 2015, the Participants executed the SONGS Decommissioning Agreement. The Agreement designates SCE as the decommissioning agent, provides for the performance of decommissioning work, and identifies the separate rights, duties, and obligations of the Participants. The Agreement requires the Participants to restore the SONGS site in accordance with applicable federal and state regulations in an effective manner. It also requires unanimous agreement among the Participants for major decisions. Accordingly, the Participants collectively oversee the decommissioning project.

II. NRC JURISDICTION AND REGULATORY FRAMEWORK

A. Jurisdiction

Under the Atomic Energy Act of 1954, the federal government exercises exclusive jurisdiction over the nuclear and radiological safety aspects of nuclear energy generation. The courts have affirmed that Congress expressly and implicitly intended to preempt state regulation pertaining to nuclear facility operations and radiological safety, including the construction, operation, and decommissioning of licensed nuclear reactor facilities.[4] Based on both the express and implied Congressional intent, the individual States have no jurisdiction over nuclear facility operations and radiological safety matters. States may exercise their traditional authority over the need for generating capacity, the type of generating facilities to be licensed, land use, ratemaking, and the like.[5]

B. NRC Regulatory Framework

Consistent with its pervasive regulatory authority over nuclear facility operations and radiological safety, the NRC has established a rigorous and comprehensive regulatory framework for all aspects of the nuclear facility life cycle, including facility design, licensing, construction, operation, decommissioning, radioactive waste transportation and disposal, and final site decontamination and restoration. The paramount priority of the NRC framework is to ensure all aspects of safety and regulation are initiated and upheld. This framework encompasses both operating nuclear facilities and decommissioned facilities. The intent is to protect public health and safety, promote security of radioactive materials, and protect the environment.

As a prerequisite to NRC licensing, each facility develops a comprehensive safety analysis report that evaluates all potential risks of facility operations and establishes risk mitigation strategies. Each facility has NRC-approved technical specifications that set forth specific parameters within which the facility must be operated. The NRC license is conditional

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[4] *See* Pacific Gas & Electric Company v. State Energy Resources Conservation and Development Commission, 461 U.S. 190 (1983), at 205 and 212; Northern States Power Co. v. Minnesota, 447 F.2d 1143, (8th Cir. 1971) at 1152-53 (The implied Congressional intent arises from the pervasiveness of the federal regulatory scheme that Congress directed and that the NRC (successor agency to the U.S. Atomic Energy Commission) has carried into effect through the promulgation and enforcement of detailed regulations governing the licensing of atomic power plants).

[5] *See* Pacific Gas & Electric Company v. State Energy Resources Conservation and Development Commission, 461 U.S. 190 (1983), at 205 and 212.

based on the facility's compliance with all such parameters. The NRC continuously oversees plant operations through various means, including the use of on-site inspectors and a robust enforcement program. Enforcement sanctions may include notices of violation, monetary fines, or orders to modify, suspend, or revoke a license or require specific actions because of a public health issue.

The NRC license for each nuclear facility remains in effect until the facility is decontaminated and decommissioned, and all federal requirements for license termination have been fulfilled by the licensee and verified by the NRC. Thus, SONGS will remain subject to the NRC's jurisdiction and regulatory framework until decommissioning and license termination are completed. NRC license termination is currently scheduled to be completed by 2051.

III. SONGS SAFETY PROGRAMS

Safety is paramount at SONGS and an SCE core value. SCE expects all workers at SONGS, whether utility employees or contractors, to perform all work safely and in accordance with NRC and other regulatory requirements. SCE goes to great lengths to ensure that all workers are properly trained and equipped to perform all SONGS decommissioning work safely.

A. SCE Safety Program

SCE is committed to maintaining a strong safety culture throughout company operations, including SONGS decommissioning. We do this by creating and sustaining a work environment that values:

- Having every employee leave the workplace unhurt;
- Using work behaviors and practices that uncompromisingly protect the safety of everyone;
- Caring for the safety of each other; and
- Stopping work anytime unsafe conditions or behaviors are observed until the job can be completed safely.

SCE strives to achieve the continuous commitment and dedication by all workers to follow these values to assure that the safest workplace is established and that the safest work behaviors are always used to prevent hazardous conditions and injuries. SCE trains all workers, as applicable, on using a variety of human performance and safety awareness tools. Among other areas of the company, these tools are deployed at SONGS and include: (1) completing meticulous pre-job planning, pre-job briefs, and safety observations during work; and (2) requiring appropriate safety equipment and personal protective equipment, personal situational awareness and attention to detail, procedural compliance, and three-way communication throughout each activity. SCE insists upon their use, and monitors adherence through a variety of human-performance / safety metrics. Every worker is also authorized to stop work and obtain clarification any time a question arises regarding the safe performance of any job.

SCE has instituted several oversight mechanisms to help ensure that work proceeds safely at SONGS, and to monitor and report on safety performance. SCE uses a focused, risk-based observation program through which qualified safety inspectors personally observe the performance of spent fuel transfer[6] and decommissioning activities and provide real-time safety recommendations as needed. The SONGS Safety group continually monitors safety performance, including near-misses and other lessons learned, and provides frequent safety

[6] See Section IV.B for further discussion regarding the risks during spent fuel transfer activities.

reports to the SONGS Chief Nuclear Officer and senior leadership team. SONGS safety performance is also reviewed by the Nuclear Oversight Board, an independent team of nuclear industry executives that provide objective input to SONGS leaders regarding all aspects of nuclear facility operations including safety. SONGS also employs a corrective action program that performs in-depth evaluations of all plant incidents or accidents.

B. Decommissioning General Contractor (DGC) Safety Program

In December 2016, the Participants retained SONGS Decommissioning*Solutions* (SDS), a consortium of Energy*Solutions* and AECOM, as the Decommissioning General Contractor (DGC) to perform a substantial portion of the SONGS decommissioning work scope.

SDS staff has substantial experience and expertise in performing large-scale nuclear decommissioning projects similar to SONGS. SDS commenced mobilizing its SONGS decommissioning team in 2017, and has assumed the performance of many plant functions that were previously performed by SCE. SDS will commence physical decontamination and dismantlement activities at SONGS upon authorization from the California Coastal Commission (CCC) when it issues the Coastal Development Permit (CDP) required for major decommissioning activities.

Like SCE, SDS implements a comprehensive nuclear and industrial safety program that meets all NRC and other regulatory requirements. All other contractors are also required to implement robust and comprehensive safety programs associated with their work on the SONGS decommissioning project.

C. SCE Oversight of Safety

SCE, as decommissioning agent on behalf of the other Participants, actively oversees the performance of all decommissioning activities, whether by utility personnel or its contractors. The purpose of SCE's oversight is to assure that: (1) each decommissioning work scope is performed safely and in accordance with site procedures; and (2) the site is restored to a radiologically safe condition suitable for future uses.

For example, if a work scope involves the demolition, removal, and disposal of a particular building and its foundations, SCE's oversight helps ensure that the building and foundations are removed safely and in their entirety. It also helps ensure that the disposal of all associated waste materials is performed completely and documented properly, in accordance with NRC and other regulatory requirements. Through its active oversight, SCE will stop decommissioning work if it is not being done safely in accordance with regulatory requirements.

As the decommissioning agent for the Participants, SCE is ultimately responsible for making sure that there are no remaining impediments to terminating the NRC licenses and the

site leases and grants of easement after all decommissioning and final site restoration work is completed.

IV. DISCUSSION ON EXISTING RISKS

A. Risk – Operational (Spent Fuel Pool Operations)

1. Description of Risk

All fuel that remains in the Units 2 and 3 spent fuel pools are scheduled to be removed from the pools and transferred to the SONGS ISFSI. Until the fuel is removed, the spent fuel pools and all necessary equipment will continue to operate. The primary risk resulting from spent fuel pool operations is the potential for insufficient cooling to compromise the intended state of the spent fuel. This could result from circumstances such as a seismic event that causes damage to the spent fuel cooling system components, or a long-term power outage.

2. Mitigation of Risk

The primary function of the Operations group is to safely maintain spent nuclear fuel in the pools and the ISFSI. This includes operating, inspecting, and testing the remaining in-service plant equipment within the requirements of the NRC license, defueled technical specifications, and operating instructions. SONGS' NRC-certified fuel handlers keep the spent fuel pools operating properly, operate the plant systems that provide and support spent fuel pool cooling, and perform periodic testing to make sure the equipment continues to perform within design parameters.

The spent fuel pool meets NRC seismic design requirements, and the spent fuel cooling system consists of redundant, engineered components to help ensure that spent fuel cooling capability is maintained. In addition, SONGS has a back-up diesel generator to provide electric power in the event there is a power outage at the site. To further mitigate the risks associated with spent fuel pool operations, all utility workers and contractors, including the Operations group, adhere to the following:

- Use detailed engineered procedures for all spent fuel pool operations activities. Using these procedures helps ensure that work activities are performed and completed in a deliberate and predictable manner.
- Participate in a pre-job brief each day before a work activity commences. Here, each task is discussed in detail, and questions are answered to help ensure that everyone has a clear understanding of the process and expected outcomes.
- Review the current radiological safety requirements for the spent fuel pool area as a condition of entry into the area, wear dosimetry and protective clothing, and follow radiological safety procedures to keep exposure to radioactive materials as low as reasonably achievable.

- Use three-way communications (i.e., direction provided, acknowledgement and repeat-back of the direction, and final confirmation) throughout all stages of a work activity, and the phonetic alphabet when appropriate (e.g., saying "Bravo 1" instead of "B1"), to help avoid miscommunications.

All workers are authorized and encouraged to stop work and ask for clarification any time an uncertainty or unexpected result arises. All work activities are subject to NRC and SCE quality assurance oversight to provide independent assurance that they are performed safely and correctly in accordance with applicable procedures.

After all fuel is transferred out of the spent fuel pools, the risks associated with spent fuel pool operations will be permanently eliminated. The pools will then be drained, decontaminated, and decommissioned.

B. Risk – Fuel Transfer Operations (FTO)

1. Description of Risk

SCE retained Holtec International to design, license, and construct an expansion to the ISFSI and to transfer all remaining Units 2 and 3 fuel from wet storage in the spent fuel pools to dry storage in the ISFSI.

The fuel transfer process includes the following steps:

1. Load up to 37 fuel assemblies into a multi-purpose canister (MPC).
2. Insert the MPC into a shielded transfer cask (cask) and weld a shielded lid on the MPC.
3. Transfer the cask from the pool to the ISFSI via a specially-designed trailer.
4. Transfer the cask from the trailer to a vertical cask transporter (VCT) and lower the MPC out of the cask and into the ISFSI canister enclosure cavity (CEC).

The potential risks of FTO include the dropping of a fuel assembly in the spent fuel pool or an MPC; mishandling a cask while in transit to the ISFSI; or mishandling an MPC during transfer into a CEC.

2. Mitigation of Risk

Before commencing the transfer of fuel from the spent fuel pools to the ISFSI, SCE required that Holtec submit its fuel transfer plan and safety program for review and approval. Upon approval, Holtec performed a series of "dry run" cask loading and transfer simulations to demonstrate to SCE, and ultimately to the NRC, that it could accomplish the transfers safely and efficiently. These "dry runs" were performed in the presence of NRC inspectors; actual transfers could not commence until the NRC provided its approval.

Upon receiving NRC approval, Holtec commenced the FTO in one spent fuel pool with the intent to perform multiple transfers from that same pool before commencing fuel transfers from the other pool. Other safety mechanisms were incorporated to support FTO, such as the use of single failure-proof cranes[7] at the spent fuel pools and on the vertical cask transporters. This provides an additional level of assurance that fuel assemblies and MPCs/casks can be lifted safely within the fuel handling buildings and at the ISFSI with a substantially reduced risk of being dropped or mishandled.

To further mitigate the risks associated with fuel transfer operations, all utility and contract workers use detailed engineering procedures for all FTO activities. Use of these procedures helps ensure that work activities are performed and completed in a deliberate and predictable manner. As the part of the procedures, the workers:

- Participate in a pre-job brief each day before a work activity commences. At this pre-job brief, each task is discussed in detail and all questions are answered to help ensure that everyone has a clear understanding of the process and expected outcomes.
- Review the current radiological safety requirements for the spent fuel pool area as a condition of entry into the area, wear dosimetry and protective clothing, and follow radiological safety procedures to keep exposure to radioactive materials as low as reasonably achievable.
- Use three-way communications (i.e., direction provided, acknowledgement and repeat-back of the direction, and final confirmation) throughout all stages of a work activity, and the phonetic alphabet when appropriate, to help avoid miscommunications.

All workers are authorized and encouraged to stop work and ask for clarification any time an uncertainty or unexpected result arises. All work activities are subject to NRC and SCE quality assurance oversight to provide independent assurance that they are performed safely and correctly in accordance with applicable procedures.

After all fuel is transferred out of the spent fuel pools, the risks associated with FTO will be permanently eliminated. All spent fuel assemblies will have been sealed into dry storage canisters and placed in the passively-cooled, robustly-secured ISFSI.

3. Current Status of FTO

On August 3, 2018, during the final step of lowering a loaded canister into the ISFSI CEC, the canister became wedged in the CEC when the bottom of the canister got caught on an

[7] Single failure proof cranes are designed to prevent load drop during the occurrence of any single failure of the lifting system, providing the highest level of operational safety in the industry.

inner ring that helps guide the canister into place. There is a very snug fit in the CECs, and it is not unusual for it to take the downloading team a few manipulations to get the canister aligned appropriately. The crew performing this work did not initially recognize that the canister had become wedged on the inner ring. However, SCE's oversight team determined the canister was not sitting properly, and the canister was repositioned and safely placed on the bottom of the CEC. At no point during this event was there any harm to an employee or the public.

Adhering to the safety principles discussed above, SCE immediately stopped further FTO activities until it could fully investigate the event and determine appropriate actions to ensure the continued safety of employees and the public. SCE has directed its contractor, Holtec, to prepare a root cause evaluation (RCE), so that appropriate corrective actions could be determined and implemented. SCE is also preparing an apparent cause evaluation (ACE) to assess its oversight of Holtec's activities and determine how SCE's oversight may be enhanced. SCE will revise FTO procedures and conduct additional training as identified through the RCE/ACE. These efforts are consistent with SCE's ongoing efforts to continuously improve all work practices at SONGS.

SCE also notified the NRC regarding the event. In September, the NRC conducted a special investigation to review SCE's investigation, causal evaluations, and planned corrective actions. SCE will not resume FTO activities until SCE is satisfied that all appropriate corrective actions have been taken, and the NRC has completed its on-site inspection activities and indicated that it is satisfied with SCE's actions. SCE remains committed to safety and a rigorous oversight process during decommissioning.

C. Risk – ISFSI Operations

1. Description of Risk

The ISFSI consists of reinforced concrete structures designed to support and shield MPCs while providing passive heat removal for long-term storage of used nuclear fuel, until the U.S. Department of Energy accepts the used fuel for disposal. The passive cooling capability relies on cool air to flow into the enclosure and the release of warm air to flow out of the enclosure. The risk of ISFSI operations is that the air flow into and out of the ISFSI could become compromised due to the presence of debris in the air inlets and/or outlets, potentially leading to an overheating of the material inside.

2. Mitigation of Risk

The ISFSI and all components are licensed by the NRC. The SONGS ISFSI is engineered to help ensure sufficient passive air-cooling capability in accordance with NRC standards for heat transfer. All air inlets and outlets are sized to provide proper air-cooling capability, and have grating installed to prevent wildlife nesting.

SONGS personnel are assigned to walk down the ISFSI at least once daily, and visually inspect all enclosure gratings for the presence of any material that could impair air flow. Any findings are promptly reported so that the materials, if any, are removed as soon as possible. Thermal detectors and radiation monitors are also installed and continuously monitored by the Operations group. Any unexpected temperature increase or increase in radioactivity would be investigated immediately.

The risks associated with ISFSI operations will continue to be present until all spent fuel is transferred from the ISFSI to a federally licensed offsite disposal facility. This is currently assumed to occur by 2049.

D. Risk – Security

1. Description of Risk

As long as nuclear fuel continues to remain on-site, and in accordance with NRC regulations (10 C.F.R. § 73.1 and 10 C.F.R. § 50.54), SONGS must maintain a security force to protect against radiological sabotage. Currently, spent fuel is maintained in wet storage in the Units 2 and 3 spent fuel pools and in dry storage in the ISFSI. Thus, the security requirements apply to both locations. Security requirements for the fuel in the spent fuel pools apply not only to the pools themselves, but also to all of the plant systems that are required to operate the pools. The security risks at SONGS will be substantially reduced after all spent fuel has been transferred to the ISFSI because there is a smaller footprint to protect and the ISFSI is a passive system (i.e. no other equipment requires security protection).

2. Mitigation of Risk

As required by NRC regulations, the physical security of the licensed special nuclear material (nuclear fuel) is protected by the SONGS Security force, and by the concentric areas of graduated security features at the plant site.

The SONGS Security force is comprised of highly-skilled officers who must qualify and maintain applicable NRC security qualification standards. To maintain their capability to detect and deter threats, SONGS Security officers participate in ongoing training exercises that include firearm range qualifications, force on force drills, etc.

SONGS Security personnel monitor the plant boundaries pursuant to SCE's license and NRC's requirements. There are three security boundaries at SONGS. The first is the plant boundary, which is the perimeter fence that provides the outermost level of protection. Inside the plant boundary is the Owner Controlled Area (OCA), which is subject to an increased level of protection. All workers and visitors to the OCA must have been authorized in advance by SONGS Security, and must continually display a SONGS-issued photo identification badge.

The third and highest level of protection is the Protected Area (PA). This level of protection is necessary due to the radiological materials located within this boundary. This boundary is surrounded by substantial physical barriers and state-of-the art intrusion detection systems, and is continually monitored by the armed SONGS Security force. All personnel and equipment access to the PA is controlled by the following activities: (1) personnel who have unescorted access to the PA are subject to increased initial and ongoing screening requirements, as well as to annual retraining requirements; and (2) all vehicles and equipment are searched by SONGS Security officers before they are allowed to enter the PA. This multi-faceted approach to security provides an effective level of assurance against the security risks that may be encountered at SONGS.

There are currently two PA's at SONGS, one that includes the spent fuel pools and one that includes the ISFSI. After all spent fuel is removed from the spent fuel pools, the PA that includes the spent fuel pools will be no longer be needed. The ISFSI PA will remain in place until all spent fuel is removed, which is currently scheduled to occur by 2049.

E. Risk – Industrial Safety

1. Description of Risk

As a large industrial facility that uses heavy equipment, energized electrical circuits, pressurized fluid systems, and hazardous chemicals, various industrial safety risks associated with these activities and materials exist at SONGS. It is imperative, therefore, that all work activities at SONGS are performed safely to avoid industrial accidents and injuries, electrical shock, and chemical exposures.

2. Mitigation of Risk

As discussed above, SCE, as the decommissioning agent, and all contractors who perform work at SONGS, are required to implement robust safety programs that meet or exceed federal and state requirements. These programs emphasize a safety-first culture and employ meticulous planning, pre-job briefs, appropriate safety equipment and personal protective equipment, personal situational awareness and attention to detail, procedural compliance, and three-way communication throughout each activity. The programs are also designed to maintain workers' exposure to radiation as low as reasonably achievable.

As relevant safety lessons are learned, they are disseminated through electric and nuclear industry organizations, to peer facilities so that each facility can benefit from and leverage each other's experiences. When SCE receives such notices concerning other facilities, the notices and information are shared with onsite contractors. In addition, briefings are conducted to disseminate the information to workers to help reinforce good safety practices and avoid or eliminate unsafe behaviors. Finally, before any major decommissioning activity is

performed at SONGS, the performance of such activity at other facilities is reviewed to identify additional insights and perspectives into how the activity may be performed more safely and efficiently at SONGS.

V. CONCLUSION

The decommissioning of SONGS is a major activity that will be performed by SCE and its contractors over a period of many years. Nuclear decommissioning projects involve both radiological safety aspects that are regulated exclusively by the federal government, and industrial safety aspects that are subject to both federal and state regulation. Various decommissioning and spent fuel storage activities will be performed until the project is completed, which is expected in 2051.

The spent fuel pool operations and fuel transfer operations represent the two most significant risk exposures of the SONGS decommissioning project. However, after these activities are completed, these risks will be permanently eliminated. The spent fuel pools will be drained, decontaminated, and decommissioned, and all spent fuel assemblies will have been sealed into dry storage canisters in the passively-cooled, robustly-secured ISFSI to await future shipment to an offsite disposal facility.

Safety is paramount to SCE. To help ensure that SONGS decommissioning activities are safely performed by both SCE and its contractors, SCE has identified and analyzed numerous risks associated with the SONGS decommissioning project and established a robust safety program that adheres to NRC radiological safety regulations and federal and state industrial safety regulations. SCE also insists that all contractors performing SONGS decommissioning activities have similarly robust and compliant safety programs. As the decommissioning agent ultimately responsible for decommissioning safety, SCE will continue to provide thorough oversight of all utility- and contractor-performed decommissioning activities throughout the duration of the project.

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Southern California Edison Company's

Risk Assessment and Mitigation Phase

Appendix B
Transmission & Substation Assets

Rosemead CA
November 15, 2018

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I. Executive Summary

A. Overview

Southern California Edison (SCE) owns and maintains transmission lines, sub-transmission lines, and substation assets. These assets are essential to moving power over long distances, to maintaining grid reliability, and to serving the energy demands of our customer base.

This appendix explores the potential direct[1] safety risks associated with transmission lines, sub-transmission lines, and substation assets that are not addressed within SCE's nine top safety risks. The safety impact of the risk associated with these assets did not rise to the level of inclusion as a top safety risk within our RAMP report. However, SCE received interest from stakeholders[2] during pre-filing briefings to better understand the potential safety-related risks of these assets. Accordingly, SCE summarizes in this Appendix how these assets can potentially create safety risks.[3]

B. Scope of Appendix

Table I-1 SCE details the scope of this Appendix.

[1] Direct safety impacts are first-order consequences of risk events that directly result in an injury or fatality.

[2] Both the Commission's Safety Enforcement Division (SED), and Office of the Safety Advocate (OSA) expressed interest in transmission and substation level safety risks, whether they create direct or indirect safety impacts.

[3] This Appendix does not provide a bowtie or any quantitative analysis of the potential risks, as is provided in the nine RAMP risk chapters.

Table I-1 - Appendix Scope

In Scope	• Risks associated with transmission, sub-transmission, or substation assets not covered in the nine RAMP risk chapters. These include risks associated with, but excluded from the scope of, the following RAMP chapters: Contact with Energized Equipment, Wildfire, and Underground Equipment Failure.[4] • Qualitative evaluation of examples of safety risks associated with transmission, sub-transmission, and substation assets.
Out of Scope	• Risks associated with transmission, sub-transmission, or substation assets that are addressed in the other six RAMP risk chapters (i.e. impacts related to Building Safety; Cyberattack; Employee, Contractor & Public Safety; Hydro Asset Safety; Physical Security; Climate Change). These chapters do not exclude these assets. • Indirect, or second-order, safety impacts resulting from widespread electric service interruptions.[5] • Quantitative and comprehensive evaluation of safety risks associated with transmission, sub-transmission, or substation assets, using risk bowtie structure and RAMP model analysis.

C. Types of Risks Evaluated in this Appendix

There are two general types of direct safety risks related to transmission lines, sub-transmission lines, and substation assets: (1) Contact with energized equipment, where a person makes contact with the system while the system is intact and operating normally; and, (2) Equipment and/or structure failure where a person is injured as a result of asset failure. In

[4] The Contact with Energized Equipment and Wildfire chapters focus on distribution-level overhead conductor. The Underground Equipment Failure chapter also focused on distribution-level equipment.

[5] Widespread electric service interruptions have obvious direct *reliability* consequences. However, they do not typically have direct *safety* consequences. This is the primary reason why this risk was not included as one of SCE's RAMP risks (In this RAMP report, SCE does not address the indirect, second-order safety impacts from risk events). Widespread electric service interruptions can potentially cause loss or disruption of other services that, in turn, can be contributing factors to serious injuries or fatalities. The elevated potential for indirect safety impacts from such widespread interruptions is one of the items that distinguishes safety risks associated with transmission and sub-transmission facilities from the safety risks associated with distribution facilities. At the transmission level, the relationship between reliability performance and secondary safety impacts means that the consequences can be more widespread than at the distribution level. However, for reasons stated in Chapter 1 - RAMP Overview, we do not attempt to evaluate those indirect impacts in this RAMP report, including within this Appendix.

this Appendix, SCE provides examples of potential safety risks associated with these assets, including:[6]

- Transmission Line Clearances;
- Transmission Conductor and/or Conductor Attachment Failure;
- Transmission Line Structure Failure;
- Substation Transformer Failure; and
- Substation Circuit Breaker Failure.

[6] This should be considered a list of examples, and not an exhaustive list of safety risks associated with transmission and sub-transmission lines and substations assets.

II. Description of SCE's Electric System

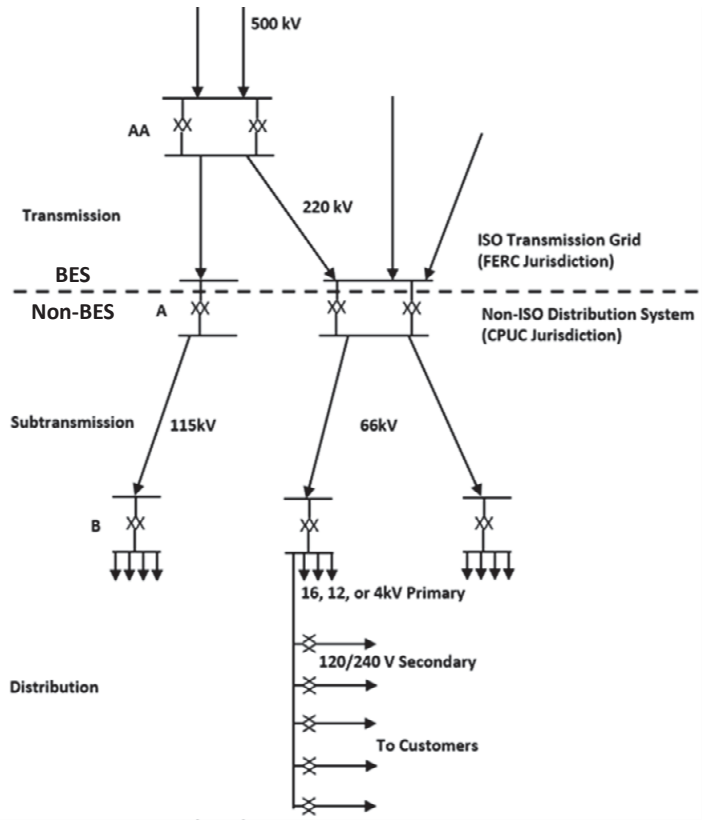
The Bulk Electric System (BES) consists of electric facilities and control systems necessary for operating an interconnected electric transmission network. In general, SCE's portion of the BES includes all transmission lines operating at 220 kV or higher and all substation facilities operating at 220 kV or higher. These facilities fall under Federal Energy Regulatory Commission (FERC) jurisdiction, are subject to NERC Reliability Standards,[7] and are under the operational control of the California Independent System Operator (CAISO).

The system of facilities used in the local distribution of electric energy are referred to as "local distribution" facilities and are not part of the BES. In general, SCE's local distribution facilities include sub-transmission lines typically operating at 66 kV or 115 kV, substation facilities typically operating at 66 kV or 115 kV, and distribution lines and substation facilities operating at voltages below 66 kV.[8] SCE's non-BES facilities are under California Public Utilities Commission (CPUC) jurisdiction and SCE operational control. A simplified overview of SCE's electric system, showing the distinction between BES and non-BES facilities, is shown in Figure II-1 below.

[7] The U.S. Energy Policy Act (EPA) of 2005 authorized the creation of an Electric Reliability Organization (ERO). The EPA of 2005 was triggered in part by concerns generated by the August 2003 blackout that affected 40 million people in the mid-western and northeastern United States and 10 million people in eastern Canada. On July 20, 2006, the Federal Energy Regulatory Commission (FERC) issued an order in Docket No. RR06-1-000 certifying the North American Electric Reliability Corporation (NERC) as the nation's Electric Reliability Organization (ERO) under Section 215 of the Federal Power Act. As the ERO, NERC has been granted the authority to develop and enforce reliability standards applicable to all owners, operators, and users of the bulk power system, rather than relying on voluntary compliance.

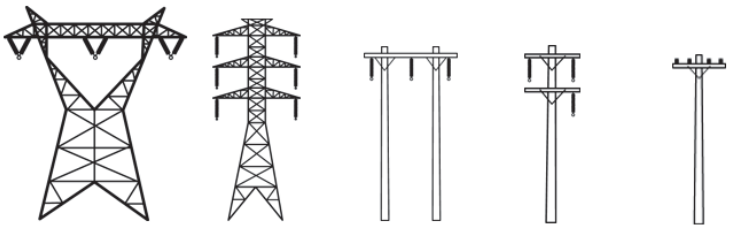
[8] SCE does have some sub-transmission lines and substation assets below 220 kV that are also BES facilities. These are the exception rather than the rule; the vast majority of SCE's sub-transmission system is classified as non-BES.

Figure II-1 – SCE's Electric System (BES and non-BES facilities)



During the 20th century, the use of higher voltages for transmission became the industry standard. Higher operating voltages require lower levels of current for similar levels of power transfer. Higher transmission voltages are accommodated through transmission tower designs that include taller towers, longer insulators, and greater phase spacing. In turn, higher voltages accommodate longer lines by means to lower losses, less voltage drop, and greater power transfer capabilities. Figure II-2 below illustrates the differences in construction, approximate effective range, and approximate nominal capacity in MW of typical transmission lines (500 kV and 220 kV), sub-transmission lines (115 kV and 66 kV), and distribution lines (12 kV and other distribution voltages).

Figure II-2 – Comparison of Transmission, Sub-transmission and Distribution Lines



	500 kV	220 kV	115 kV	66 kV	12 kV
Effective Range	Several Hundred Miles	Hundred Miles	Fifty Miles	Twenty Miles	Three Miles
Nominal Capacity	2,400 MW	650 MW	200 MW	120 MW	10 MW

The larger geographic reach of transmission lines is further extended through using BES substations that connect transmission lines together. Substations provide the capabilities of both switching and voltage transformation. In other words, substations link transmission lines to other transmission lines, and also link high voltage transmission lines to lower voltage sub-transmission lines. The interconnectivity that substations make possible tends to extend the wide area geographic reach of transmission lines, sub-transmission lines, and BES substation assets.

III. Examples of Transmission, Sub-transmission, and Substation Safety Risks

In this Appendix, SCE provides examples of safety risks that can result from contact with energized equipment, or equipment/structure failure, in the context of transmission, sub-transmission, and substation assets. We also summarize at a high level the existing controls and mitigations to manage these risks.

A. Transmission Line Clearances

1. Risk Description

This represents transmission line or sub-transmission line discrepancies leading to General Order (GO) 95 clearance violations. This is an example of contact with energized equipment risk type.

A discrepancy is any condition found in the field requiring remediation to meet GO 95 requirements during peak load conditions. Discrepancies have been prioritized based on criteria, such as line sag when operating at our below 130 degrees Fahrenheit, and potential risk to public safety and reliability. Safety risks associated with inadequate vertical clearances are elevated in locations that do not meet GO 95 clearance requirements, as high voltage transmission lines are more accessible for human contact.

2. Controls and Mitigations

Remediation work to resolve discrepancies includes replacing towers, poles and conductors, raising towers, clearing brush, replacing insulators, adding or lowering cross arms, removing slack, relocating lines, and other efforts. In 2015, SCE finalized a work plan to remediate discrepancies on CAISO lines by 2025 and on non-CAISO facilities by 2030. This work is performed through SCE's Transmission Line Rating Remediation program (TLRR).[9]

B. Transmission Conductor and/or Conductor Attachment Failure

1. Risk Description

This represents the failure of transmission line or sub-transmission line conductor and/or conductor attachments, which can lead to public injuries/fatalities. This is an example of equipment and/or structure failure risk type.

[9] See A.16-09-001, SCE's Test Year 2018 General Rate Case, Exhibit SCE-02, Volume 7 for more discussion on SCE's TLRR program.

As transmission and sub-transmission conductors, splices, insulators, and associated hardware age, they have an increased risk of failing. Aging conductor is vulnerable to the stresses caused by circuit relays and other environmental factors. This may result in a failure and can cause conductor to fall to the ground, leading to potential wildfires, personal property damage, or third-party personal contact. These failures can also impact the integrity of the BES system, as well as the reliability of service to our customers.

2. Controls and Mitigations

To mitigate aging conductor and conductor attachment risks, SCE replaces aging infrastructure on an annual basis within the Transmission Infrastructure Replacement program.[10] Replacements are prioritized based on age, wire size, deterioration identified via inspections, and documented interruptions.

C. Transmission Line Structure Failure

1. Risk Description

This represents the failure of transmission line or sub-transmission line structures, which can lead to public injuries/fatalities. This is an example of equipment and/or structure failure risk type.

Aging lattice steel structures and similar structures are at risk of failing due to corrosion, especially in coastal regions subject to marine layer or moisture source. This can have both a direct safety risk to our workers and members of the public, as well as impact the reliability of our service to customers.

2. Controls and Mitigations

SCE is presently developing a plan to identify transmission line and sub-transmission line structures that pose the greatest risk of failing. SCE is also evaluating a range of mitigation options to address these structures, such as applying a coating to prevent further corrosion, or replacing structures. SCE anticipates providing additional details as part of the upcoming 2021 GRC.

[10] See A.16-09-001, Exhibit SCE-02, Volume 7, for a full description of SCE's Transmission Infrastructure Replacement program.

D. Substation Transformer Failure

1. Risk Description

This represents the catastrophic failure[11] of substation transformers, which can lead to public and/or worker injuries/fatalities, as well as impact BES system integrity and affect service reliability to our customers. This is an example of equipment and/or structure failure risk type.

Transformers are one of the most critical pieces of equipment in a substation. Transformers are used to lower transmission voltages down to sub-transmission voltages and sub-transmission voltages down to distribution voltages, where a majority of customers draw their power. When a transformer fails, it may disturb the power flow to the system, causing a reliability consequence. In some cases, a transformer failure can be catastrophic in nature. If there are personnel near the transformer when a catastrophic failure occurs, those individuals are exposed to greater safety risks. In addition, catastrophic transformer failures can also damage other substation equipment and may cause widespread electrical service interruptions.

2. Controls and Mitigations

SCE has multiple programs to mitigate transformer failure related risks. These SCE maintenance and inspection programs monitor and maintain the condition of transformers.[12] The Substation Infrastructure Replacement (SIR) program[13] replaces aging transformers preemptively before they reach their end of usable lives. These mitigations are intended to reduce the number of transformer failures, which reduces the associated direct safety risks.

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[11] Generally speaking, SCE uses the term "catastrophic" to mean a sudden and complete failure of a piece of electrical equipment associated with an uncontrolled release of energy.

[12] See A.16-09-001, Exhibit SCE-02, Volume 6, for more details on SCE's substation maintenance and inspection programs.

[13] See A.16-09-001, Exhibit SCE-02, Volume 8, for more details on SCE's Substation Infrastructure Replacement program.

E. Substation Circuit Breaker Failure

1. Risk Description

This represents the catastrophic failure of substation circuit breakers, which can lead to public and/or worker injuries/fatalities. This is an example of equipment and/or structure failure risk type.

Substation circuit breakers are protective devices that primarily function to interrupt current flow when a fault condition occurs. This prevents damage to equipment and minimizes the impact of disturbances on the system, which can under certain circumstances lead to safety impacts.[14] Circuit breakers also provide a means to carry out routine switching operations in order to perform maintenance on substation equipment. There are two potential failure modes for circuit breakers that can result in potential safety impacts:

- Failure of circuit breaker to operate during fault event; and
- Catastrophic failure of circuit breaker during fault event.

The failure of a circuit breaker to operate during a fault could result in longer fault durations or inadequate fault clearing. This can result in greater damage to equipment and elevated safety risks. If a circuit breaker fails catastrophically, it could also expose nearby personnel to additional safety risks. A failing circuit breaker can make it necessary to use backup protection devices to clear faults. This increases the resulting size of electrical service interruptions and associated indirect safety risks.

Some circuit breakers are identified as potentially being subjected to more fault duty than they are rated for during a fault condition. These are referred to as overstressed circuit breakers. Circuit breakers identified as overstressed are more vulnerable to the failure modes described above.

2. Controls and Mitigations

SCE has multiple programs to mitigate risks related to circuit breaker failures. Our maintenance and inspection programs monitor and maintain circuit breakers conditions. The SIR program replaces aging circuit breakers preemptively before they reach the end of their

[14] Failures of protective relays can similarly lead to safety impacts. SCE includes replacing protective relays as part of our infrastructure replacement program.

usable lives. The Substation Equipment Replacement Program (SERP) replaces overstressed[15] circuit breakers. These mitigations are intended to reduce the number of circuit breaker failures, which in turn reduces the associated reliability and safety risks.

[15] Overstressed circuit breakers can be potentially subjected to more fault duty than they are rated for during a fault condition. Circuit breakers identified as overstressed are more vulnerable to the two failure modes described above.

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

(U 338-E)

Southern California Edison Company's

Risk Assessment and Mitigation Phase

Appendix C
Seismic Events

Rosemead CA
November 15, 2018

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II. Seismic Activity in Southern California 2

III. Risk of Seismic Activity to SCE Environment 3

IV. SCE's Approach to Assessing and Mitigating Seismic Risk 5

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I. Introduction

Because we are located in southern California, seismic events are a key safety risk for SCE. While major seismic events occur infrequently, such events can seriously impact our critical assets and facilities. SCE must proactively harden our critical assets and facilities to mitigate the safety, reliability, and financial consequences of these events.

As discussed in Chapter I – RAMP Overview, SCE chose to address seismic event risk in this RAMP report as a risk driver, instead of as a discrete risk event. This approach better aligns with the risk bowtie structure SCE employs throughout this report. Accordingly, we include seismic events as a key risk driver in the Hydro Asset Safety and Building Safety chapters.[1]

Because of the importance of mitigating the impacts of seismic events on our critical assets and facilities, SCE provides additional detail on our Seismic Assessment & Mitigation Program in this Appendix.

[1] Because this RAMP report focuses on safety risks, we do not address in the RAMP risk chapters the considerable efforts that SCE undertakes to mitigate reliability risks associated with seismic activity.

II. Seismic Activity in Southern California

SCE operates in one of the most seismically active areas in the United States. SCE must plan for a major earthquake, as it represents one of the most catastrophic and widespread incidents that could occur in California. In a 2015 report, the United States Geological Survey (USGS) introduced its latest earthquake model, the third Uniform California Earthquake Rupture Forecast (UCERF3).[2] The UCERF3 model shows a higher prediction rate for earthquakes in Southern California, with magnitudes between 5.0 and 8.0, compared to what prior earthquake models included.

According to the USGS report, the increased threat is due to the many interconnected faults in California. These interconnected faults can trigger seismic activities in one another. This increases the probability of multi-fault ruptures. The probability is significant due to the number of faults interconnected with the San Andreas Fault, which runs through nearly all of the state and is most likely to be the source of the most catastrophic earthquakes in California. The report estimates that there is a 93 percent chance Southern California will experience one or more earthquakes of magnitude 6.7 (the magnitude of the 1994 Northridge earthquake) or greater in the next 30 years. Additionally, there is an estimated 36 percent chance of an earthquake of magnitude 7.5 or greater in the next 30 years, which would be the largest earthquake experienced by Southern California since the 1857 Fort Tejon earthquake. These predictions drive SCE's focus on preparing for and mitigating the potential impacts of moderate to large-scale earthquakes.

Table II-1 – USGS Prediction of Southern California Seismicity

Magnitude (Greater than or equal to)	Average Repeat Time (years)	Likelihood of one or more events in 30 years
6.0	2.3	100%
6.7	12	93%
7.5	87	36%
8.0	522	7%

[2] "UCERF3: A New Earthquake Forecast for California's Complex Fault System." US Geological Survey Fact Sheet 2015-3009.

III. Risk of Seismic Activity to SCE Environment

SCE maintains approximately 1,300 buildings that cover more than 7.3 million square feet. These buildings include 89 buildings supporting administrative functions, 128 buildings supporting service centers and warehouses, 8 buildings supporting critical facilities and data centers, and 1,088 buildings supporting substation and generation facilities. In addition, SCE maintains over 13,000 circuit miles of transmission lines, over 4,600 distribution circuits, and hundreds of thousands of substation and distribution transformers, circuit breakers, underground structures, etc. Lastly, SCE owns and operates numerous electric generating facilities, including peakers, baseload, and hydroelectric stations and dams. This infrastructure system is widely dispersed, complex, and interdependent.

A major earthquake can have a direct impact on this infrastructure, and also extend beyond safety concerns and physical damage to infrastructure and buildings. Those impacts also affect the resiliency of the Company as a whole by disrupting our workforce and damaging or disabling the infrastructure we rely on to deliver electricity to our customers.

Major earthquakes can profoundly impact safety, service reliability, and community resiliency. The 1994 Northridge earthquake was a significant milestone in the evolution of earthquake codes and standards. Seventy-eight percent of SCE non-electric facilities (such as occupied buildings and warehouses) were built prior to that earthquake. As a general matter, it is expected that these buildings are more vulnerable to earthquakes than those built to modern codes and standards.

In addition, SCE owns and operates 28 high hazard dams – some dating back as far as the early 1900's. Due to potentially catastrophic safety and reliability impacts if a dam fails, these high hazard dams are subject to state and federal inspections, and undergo dam safety reviews by an independent consultant every five years. This is further discussed in Chapter 8 – Hydro Asset Safety.

A major seismic event can severely damage SCE's infrastructure and its ability to provide electric service. SCE's electric infrastructure includes transmission lines, towers, and substations, down to distribution substations, lines, poles, and equipment. Transmission lines and towers move high-voltage electricity from locales far from SCE's service territory. The lines and towers are typically built to withstand impacts from high wind, ice-wind combinations, and unbalanced longitudinal wire loads. Major seismic activity that causes deep-seated landslides,

liquefaction,[3] lateral spreading, and ground shifting pose reliability risks to the transmission system – specifically, where towers and lines would be affected by such ground shifts associated with earthquakes.

Finally, electricity is critical when law enforcement, first responders, critical care providers, search and rescue teams, and relief organizations all respond to a major earthquake. SCE's ability to quickly restore power and continue operations following a major earthquake directly impacts how recovery progresses in the communities we serve. Restoring power after a disaster is a key indicator used by emergency managers to gauge when communities transition from response to recovery efforts.

[3] Liquefaction is a process by which water-saturated soil temporarily loses strength and behaves like a liquid. This effect can be caused by earthquake shaking and has resulted in severe damage to structures in past earthquakes around the world.

IV. SCE's Approach to Assessing and Mitigating Seismic Risk

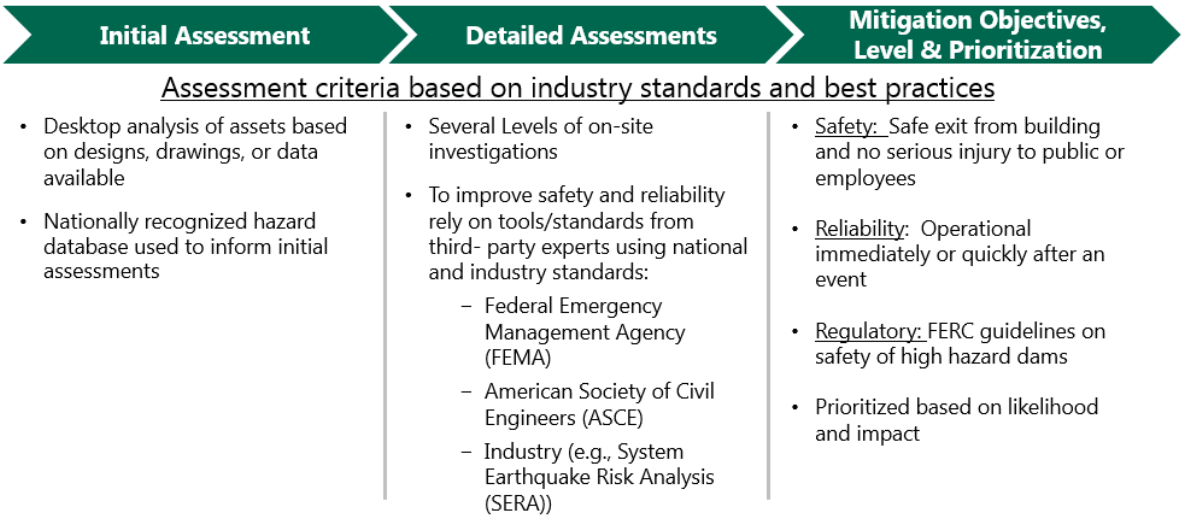
In 2016, SCE launched a company-wide Seismic Assessment and Mitigation Program to centralize and coordinate the company's ongoing seismic improvement projects for its infrastructure (electric and generation) and facilities (occupied and operational). In 2017, it added additional focus on IT and telecommunications capabilities. This centralized approach supports consistently applying best practices using recognized national standards when gathering and analyzing data, performing on-site assessments, identifying the technical and scientific subject experts, contracting with vendors, and compiling reports for the assessment and mitigation projects. Seismic mitigations are prioritized with a focus on keeping people safe and minimizing interruptions in electric service. A coordinated and company-wide seismic program is essential to help reduce the risk of a moderate or major earthquake causing substantial harm to workers, customers, and communities.

The Seismic Assessment and Mitigation Program is structured into four work streams, each of which follows a tiered and systematic approach for assessing and evaluating seismic risk and identifying and prioritizing mitigations by applying industry standards. The four workstreams are as follows:

- **Non-Electric Facilities** (Administrative and operational buildings and garages.);
- **Electric Infrastructure** (Transmission & distribution system – substations, towers, pole-mounted equipment, racks, etc.);
- **Generation Infrastructure** (Hydro, Powerhouses, Peakers, Mountainview Generating Stations);
- **IT / Telecommunications Infrastructure** (IT data centers, telecommunications sites and towers, sites housing critical IT systems).

The approach that SCE uses to assess the seismic impacts of the facilities and equipment in each of the four workstreams is illustrated in Figure IV-1.

Figure IV-1 – Risk Assessment & Mitigation Identification



A variety of standards are used to perform these assessments, including:

- **Federal Emergency Management Agency (FEMA) P-154:** Recommended methodology for Rapid Visual Screening techniques to identify, inventory, and screen buildings for potential seismic hazards;
- **American Society of Civil Engineers (ASCE) 41:** Industry standard. A three-tiered process applying the latest generation of performance-based seismic rehabilitation methodology to improve building performance in future earthquakes;
- **FEMA P-58:** Next-generation seismic performance assessment methodology that develops performance-based seismic design guidelines and stakeholder guidelines;
- **System Earthquake Risk Assessment (SERA):** Computer program used to identify seismic hazards on a system, utilizing historical performance data and estimated fragility values to calculate expected damage levels of electric equipment and infrastructure;
- **Institute of Electrical and Electronics Engineers (IEEE) IEEE-693:** Seismic design recommendations for substations including seismic criteria, qualification methods and levels, structural capacities, performance requirements for operating equipment, and installation methods;
- **Federal Energy Regulatory Commission (FERC) Division of Dam Safety and Inspections Engineering Guidelines:** Seismic guidelines for dam safety and hydropower projects

SCE's Seismic Assessment and Mitigation Program is currently focusing on the following efforts through 2020:

- **Electric** – Retrofitting transmission substations, distribution overhead equipment Racks, transmission tower assessments, and relay racks;
- **Non-electric** – Retrofitting older precast concrete tilt-up[4] and reinforced masonry buildings;
- **Generation** – Assessing high hazard dams, powerhouses, peaker plants, and Mountainview Generating station;
- **IT/Telecomm** – Assessing and retrofitting data centers and telecomm racks supporting critical applications and grid systems.

For seismic work beyond 2020, SCE will consider the following work activities for inclusion in our 2021 GRC:

- **Electric** – Retrofitting distribution substations, continuing to assess and mitigate transmission towers;
- **Non-electric** – Improving facilities that store critical electrical equipment and performing additional retrofits of buildings;
- **Generation** – Performing ongoing assessments of high hazard dams and conveyance systems; potentially retrofitting assessed facilities;
- **IT /Telecomm** – Continuing to assess IT infrastructure and reinforcing computer racks in SCE buildings.

[4] Precast concrete tilt-up buildings are built from concrete panels pre-constructed at a manufacturing facility. The panels are "tilted" into place and connected to a roof diaphragm. Roof-to-wall connections for older buildings constructed with this method have historically performed poorly in earthquakes, resulting in significant damage.

V. Seismic Events as Drivers to Multiple RAMP Risks

SCE includes seismic events as a driver in several risk chapters. Table II maps where the seismic risk is addressed in this RAMP report.

Table II – Seismic Drivers in RAMP Risk Chapters

Chapter	Description	Controls and Mitigations Proposed in Chapter
[Ch. 8] Hydro Asset Safety	Seismic event is modeled as a driver that can lead to uncontrolled and rapid release of water from SCE's hydroelectric generating assets, if they were to fail.	C1 – Seismic retrofit C6 – Instrumentation and communication improvements
[Ch. 4] Building Safety	Seismic events of magnitude 6.0 or greater are modeled as a driver to structural compromise of occupied SCE buildings.	C1 – Seismic assessment and mitigation program C2 – Facility emergency management plans M4 – Worker relocation M5 – Building Replacement

CASE: UE 374
WITNESS: MITCHELL MOORE

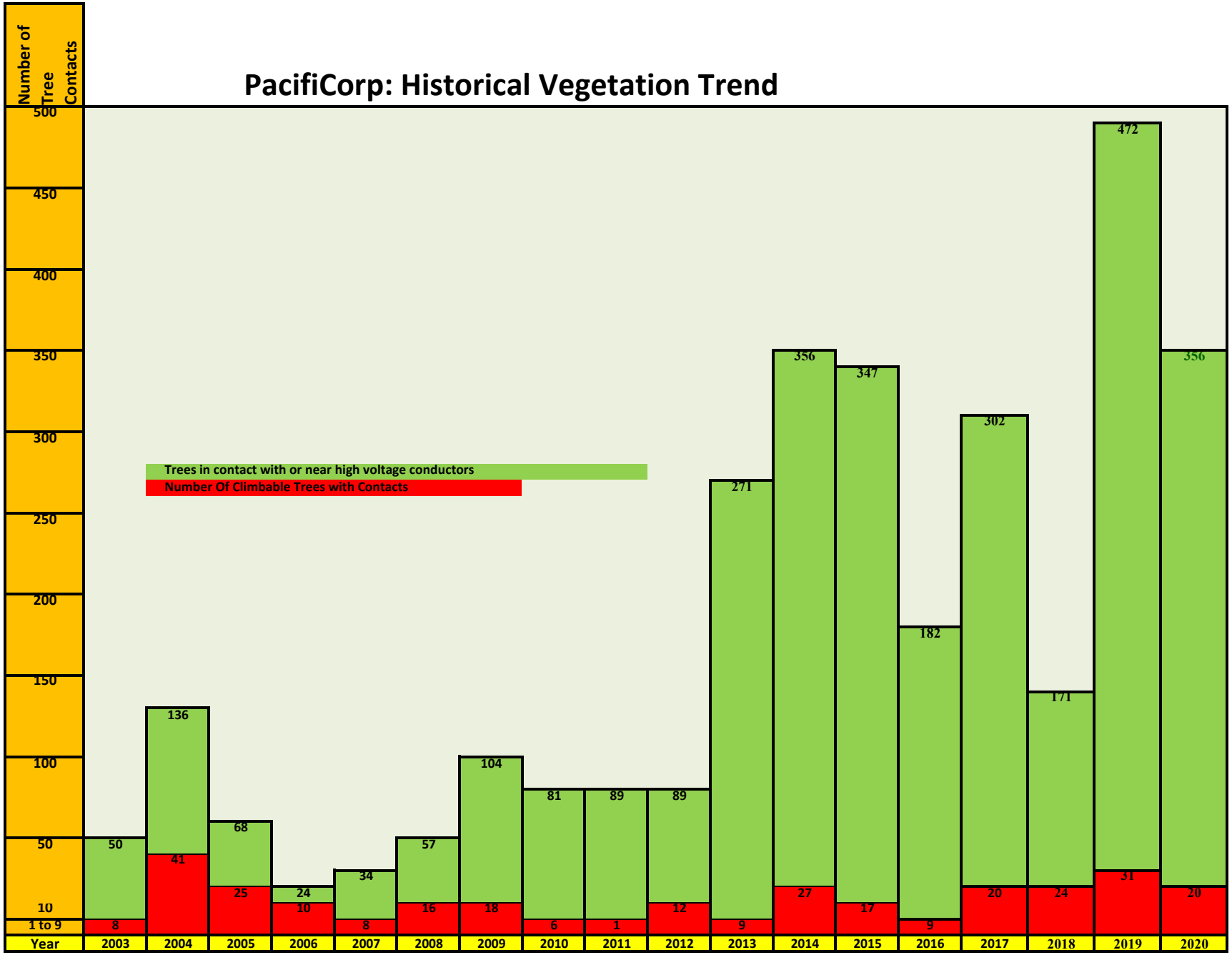
PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2704

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

PacifiCorp: Historical Vegetation Trend



CASE: UE 374
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2800

Rebuttal Testimony

July 24, 2020

Q. Please state your name, occupation, and business address.

A. My name is Paul Rossow. I am a Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon. My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes, I sponsored Staff Exhibits Staff/1200-1203.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit staff/1201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to PacifiCorp's reply testimony on the issues of Memberships and Subscriptions, and Meals and Entertainment and Miscellaneous Operations and Maintenance Expenses.

Q. Did you prepare an exhibit for this docket?

A. No

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Memberships and Subscriptions 2
Issue 2, Meals and Entertainment and Miscellaneous Operations and Maintenance Expenses 7

ISSUE 1, MEMBERSHIPS AND SUBSCRIPTIONS

Q. Please summarize your adjustment from your Opening Testimony, and PacifiCorp's response.

A. In my Opening Testimony, I proposed a downward adjustment of $197,678 in "Memberships and Subscriptions" expense, based on my analysis as described in my testimony.[1] This category of expense is comprised of: (1) Books and Subscriptions, (2) Dues and Licenses, and (3) Memberships and Subscriptions. In PacifiCorp's Reply Testimony, the Company argues that my adjustment is duplicative of an adjustment already made by the Company, is not supported, appears arbitrary, and odes not properly calculate the Oregon allocation.[2]

Q. Is Staff updating its opening testimony position adjustment regarding books, memberships, dues, licenses, and subscriptions?

A. Yes, in part. In the category of "Memberships and Subscriptions," Staff agrees with Ms. McCoy that some of Staff's initially proposed decreases were duplicative of adjustments already made. Accordingly, Staff re-examined our proposed adjustments and now recommends a $34,270 reduction to Memberships and Subscriptions. Staff's maintains its adjustments to "Books and Subscriptions" and "Dues and Licenses."

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[1] Staff/1200, Rossow/3-5.
[2] PAC/3100, McCoy/22.

Table 1 Summary Table of Staff's Adjustments

	Oregon Revenue Requirement Decrease	
Expense Category	Opening Testimony *(June 4, 2020)*	Rebuttal Testimony *(July 24, 2020)*
Books and Subscriptions	$4,634	$4,602
Dues and Licenses	$10,992	$10,916
Memberships and Subscriptions	$182,052	$18,753
Total	**$197,6781**	**$34,270**

Q. Does Staff agree with PacifiCorp's assertions that the proposed adjustments are arbitrary, without support, and improperly calculated?

A. No. Staff's proposed adjustments are based on an individual review of over 184,000 line items in an effort to categorizing and assess them based on the information provided by the Company. While Staff agrees a mistake was made in the initial "Membership and Subscription" decrease proposed in its opening testimony, Staff's strongly disagrees with Ms. McCoy assertion that Staff's approach to assessing these cost is arbitrary or without support, as we will demonstrate below.

Q. With regards to books and subscriptions, how did Staff arrive at the same decrease as in its Opening Testimony?

A. Staff's approach to assessing PacifiCorp's books and subscriptions remains the same as it was previously and in other rate cases: to find and then review each item under FERC Accounts 500 through 935 and, based on the evidence provided by Company, attempted to discern if the customer

benefits and/or employee benefits from this purchase. For this rate case, Staff reviewed over 184,000 line items and categorized 213 line items as related to "Books and Subscriptions." Staff then reviewed each item. Staff found that 34 of the items should be allowed at 100 percent and the remaining items allowed at only 75 percent. Contrary to PacifiCorp's assertion, no items were fully disallowed. Staff would note that our reduction amounts to less than 20 percent of Books and Subscriptions. In short, Staff agrees with the Company that books and subscriptions have a justifiable business purposes, but the Company failed to provide enough evidence in support of 179 of the 213 items to justify inclusion in rates at 100 percent. In these instances, Staff defaults to protecting ratepayers and discounting them by 25 percent. Then Staff uses the most recent Consumer Price Index all urban (CPI) of 0.7 percent for 2020 and 2.1 percent for 2021,[3] to escalate amounts from the base year to the test year.

Q. With regard dues and licenses expense, how did Staff arrive at the same decrease as in its Opening Testimony?

A. Staff's recommended adjustment is based on the same approach to assessing dues and licenses books and subscriptions. Staff begins by searching through over 184,000 line items. (I believe this is where Ms. McCoy mistakenly refers to our "key item search." It is used to identify items, not disallow them.) In this case, Staff found 468 items related to dues and licenses. Staff then individually assesses their merit (i.e., ratepayer

[3] See Oregon Office of Economic Analysis Forecast June 2020 (Appendix A), page 8.

benefit) based on the information provided. In this case, of the 468 items worth $102,301 that were reviewed, 288 dues and subscriptions items were allowed at 100 percent. The remaining 188 items worth $42,468 were discounted by 25 percent, at an estimated disallowance value of $10,915, or roughly 11 percent of the total charges. Then Staff uses CPI to escalate amounts from the base year to the test year.

Q. Does Staff support PacifiCorp securing books, subscriptions, licenses, or paying dues for professional organizations related to their employees as it benefits ratepayers?

A. Yes. Ms. McCoy's assertions to the contrary are incorrect. Ms. McCoy either misunderstood or mischaracterized how Staff conducts its process, which as described above, strikes a balance between the Company's needs and ratepayer protection.

Q. Please explain your updated adjustment for the final category, memberships and subscriptions.

A. Staff's analysis included the review of PacifiCorp's memberships and subscriptions 2019 O&M transaction expenses for the Oregon allocated non-payroll expenses recorded to FERC account 930.2 shown in an electronic spreadsheet format by PacifiCorp Staff witness Ms. Shelley McCoy, page 4.6 in Exhibit PAC/1302, tab 4.6.1 – 4.6.2.

Next, Staff searched through PacifiCorp's national and regional trade memberships shown in tab 4.6.1 – 4.6.2 and is proposing to disallow those expenditures related to community affairs, which are identified in red font in

Staff's workpaper on tab Membership Adj to PAC 4.6, which amounted to a disallowance of $115,081. The remaining test year expense of $1,006,013 was then applied against the Company's factor of 27.215 percent to arrive at the test year amount of $286,357. This is $18,753 reduction from PacifiCorp's revised Oregon allocated amount of memberships and subscriptions of $305,109.

To be clear Staff's policy regarding memberships and dues for organizations not related to the energy industry is to apply a disallowance of 100 percent. Staff's rationale is that while civic and community affairs organizations play a role in a strong community those expenditures are discretionary in nature, as they are not necessary in the delivery of electricity, and meant to burnish the image of the Company.

Table 2 summarizes the total Oregon allocated amount for memberships recorded in FERC account 930.2, and the disallowed amount, results in an Oregon allocated test year decrease as shown below.

Table 2 Memberships Adjustment by Staff

Memberships (FERC 930.2)	Total Oregon Allocated Amount ($)	Staff Allowed Allocated Amount ($)
National and Regional Memberships	$305,109	$286,357

Q. What is Staff's membership and subscriptions adjustment?

A. Staff's adjustment is a decrease of $18,753 from the Company's filed case for a total adjusted amount of $286,357 for memberships and subscriptions.

1 **ISSUE 2, MEALS AND ENTERTAINMENT AND MISCELLANEOUS**
2 **OPERATIONS AND MAINTENANCE EXPENSES**

3 **Q. Please summarize your adjustment from your Opening Testimony, and**
4 **PacifiCorp's response.**

5 A. In my Opening Testimony, I proposed a downward adjustment of $ 594,533
6 in O&M expense, based on my analysis as described in my testimony.[4] In
7 PacifiCorp's Reply Testimony, the Company argues that my adjustment
8 should be rejected.[5]

9 **Q. What is covered under this issue, how many line items did it amount to**
10 **in PacifiCorp's submission, and what were the total amounts proposed**
11 **for allowance in rates?**

12 A. This issue covers a broad category of expense activities including Meals &
13 Entertainment, Awards, Miscellaneous, Donations, Airfare and Travel, and
14 Lodging. There were over 79,668 line items related to these expenses
15 amounting to over $7.7 million in allowable expenses. The table below
16 provides a summary.
17

[4] Staff/1200, Rossow/11.
[5] PAC/3100, McCoy/24.

Table 3

G/L Account Descriptions	Proposed Allowable Amount
Meals & Entertainment	$ 987,482
Awards	$ 52,349
Miscellaneous	$ 4,718
Donations	$ 1,299
Airfare and Travel	$ 2,812,038
Lodging	$ 3,912,567
Total	**$ 7,770,454**

Q. What is Staff's approach to assessing the appropriate level of O&M expense related to these categories?

A. First, to be clear, the purpose of this general rate case is to set a level of O&M expense for the test year, and does not constitute a "disallowance" of any past costs actually incurred. In accordance with Commission Order No. 09-020, the Commission adopted a policy for the treatment of meals and entertainment, office refreshments, catering, gifts, and awards which it found to be discretionary. Because these cost categories are discretionary, the Commission found that they should be shared equally between customers and shareholders. The amount of expense included in the test year is based on the base year, with adjustments. Accordingly, Staff analyzes base year expenses in these categories and places them into one of three categories: 0 percent allowance; 50 percent allowance; and 100 percent allowance. As described below, each of the six categories of expenses listed above have their own logic for the application of the three types of allowance. Staff has

applied this same logic over multiple rate cases within each category and against each line item.

Table 4

	Expense Adjustments Eligibility/Applicability Logic		
G/L Account Descriptions	**100%**	**50%**	**0%**
Meals & Entertainment	Not business related expenses.	Most meal or entertainment expenses.	Eligibility on an exception basis.
Awards		All awards.	
Miscellaneous	All. None eligible.		
Donations	All. None eligible.		
Airfare and Travel	Not business related expenses.	Meal or entertainment expenses.	Most expenses.
Lodging	Not business related expenses.	Meal or entertainment expenses.	Most expenses.

Q. How does this translate into adjustments for this rate case?

A. The table below summarizes Staff's proposed adjustments for these categories of expenses, unadjusted by the two years of CPI data.

Table 5

			Rate of Disallowance and Staff's Reduction in Proposed Amount of Expenses *(Negative amounts indicate a reduction)*		
G/L Account Descriptions		**PacifiCorp Proposed Amount**	**100%**	**50%**	**Staff's Final Proposed Amount**
Meals & Entertainment		$987,481	($ 33,883)	($ 476,799)	$ 476,844
Awards		$ 52,349	$0	($ 26,174)	$ 26,175
Miscellaneous		$ 4,718	($ 4,718)	$0	$0
Donations		$1,299	($ 1,299)	$0	$0
Airfare and Travel		$2,812,038	($ 16,780)	($ 5,017)	$ 2,790,241
Lodging		$ 3,912,567	($ 11,924)	($ 0)	$ 3,900,643
Total		$ 7,770,453	($68,606)	($507,990)	$ 7,193,904

1 The total amount of $507,991 of adjustments in the table above convert to an
2 escalated amount of $522,289 for the test year using the most recent CPI.
3 **Q. How were these adjustments determined?**
4 A. Like other expenses, Staff went through line-by-line and identified each
5 expense and then, for the most part, attempted to determine if there was a
6 ratepayer benefit or legitimate business reason based on the evidence
7 provided. In the case of meals and entertainment, all expenses determined
8 to be eligible were automatically adjusted by a 50 percent to account for the
9 sharing per Commission Order No. 90-020.
10 **Q. Why does Staff automatically apply a sharing of 50 percent of meals**
11 **and expenses?**
12 A. This has been Staff's practice for several rate cases and is backed by
13 Commission Order No. 09-020. In that Order, the Commission adopted
14 Staff's principal that costs for meals and entertainment could be considered
15 discretionary and should be shared equally by ratepayers and shareholders.
16 It remains Staff's belief that this approach broadly mirrors the policy
17 associated with bonuses and the handling of these expenses for income tax
18 purposes, which also limits business meal and entertainment to 50 percent
19 of total expenses.
20 **Q. How does PacifiCorp characterize your proposed sharing, amounting**
21 **to a downward escalated adjustment of $590,895 from a total of**
22 **$7,770,453 (~ 7.7 percent), of charges related to these activities?**

A. Ms. McCoy characterizes Staff's approach to all of these disallowances as arbitrary, despite the fact the approach toward the largest disallowance mirrors federal tax practices and is documented in Commission order. Her testimony further casts Staff's approach as callous with regards to meals expenses related to critical storm restoration work or PacifiCorp staff with no other meal options than Starbucks.

Q. Has Staff's position changed regarding the disallowance of $590,895 related to meals, entertainment, and O&M non-payroll expenses?

A. No. As set forth in Table 5, above, Staff continues to propose excluding 100 percent of those O&M non-payroll expenses that have no benefit to customers and 50 percent of those expenses that Staff believes benefitted both customer and shareholders recorded under PacifiCorp's G/L Account Description titled Meals & Entertainment, Awards, Miscellaneous, Donations, Airfare and Travel, and Lodging.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 374
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2900

Rebuttal Testimony

July 24, 2020

1 **Q. Please state your name, occupation, and business address.**

2 A. My name is Max St. Brown. I am a Senior Analyst within the Energy
3 Resources and Planning Division. My business address is 201 High St.,
4 Salem, Oregon 97301-3612.

5 **Q. Are you the same Max St. Brown from Staff Exhibit 1100?**

6 A. Yes.

7 **Q. What is the purpose of your testimony?**

8 A. I am providing a statement that we have reached a settlement in principle on
9 the issues covered by the marginal cost study, rate spread, rate design, pilot
10 programs, and street lighting programs, therefore no substantive testimony on
11 these issues will be offered.

12 **Q. What is the timeline for the stipulating parties' joint testimony?**

13 A. Staff has proposed to PacifiCorp that we have a stipulation filed before
14 PacifiCorp would be due to file surrebuttal testimony (on August 18, 2020),
15 even if we are unable to get joint testimony done in that time.

16 **Q. Does this conclude your testimony?**

17 A. Yes.

CASE: UE 374
WITNESS: RUSSELL (RUSS) BEITZEL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3000

Rebuttal Testimony

July 24, 2020

Q. Please state your name, occupation, and business address.

A. My name is Russ Beitzel. I am a Senior Utility Analyst employed in the Retail Telecom & Water Regulation division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes, please see Exhibit Staff/500.

Q. What is the purpose of your testimony?

A. To rebut portions of the testimony of McCoy (PAC/3100).

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Staff Exhibit/3001, which contains responses to Staff's data requests.

1 **ISSUE 1. PACIFICORP'S EXPLANATION OF CHANGES FROM BASE YEAR TO**
2 **TEST YEAR FOR NON-LABOR EXPENSES**

3 **Q. Please summarize the Company's Reply Testimony regarding Staff**
4 **Discovery Requests.**

5 A. The Company stated that "… the Test Period data is not prepared at the same
6 level of detail as is available for the actual data from SAP. Therefore,
7 comparisons of the non-labor data for the Test Period versus the Base Period
8 and previous two calendar years are likely not meaningful."[1].

9 Staff requests that each major utility company provide their FERC account data
10 split between labor and non-labor (e.g. via standard data request 058). It is
11 important to isolate non-labor costs as they are generally not affected by labor
12 contracts or other payroll related increases.

13 Staff often splits the analysis functions between different people based on labor
14 and non-labor. Once assigned, Staff uses the Urban CPI index, for non-labor
15 accounts, as part of the analysis of growth from Base Year to Test Year.

16 **Q. Does Staff agree with the Company's position?**

17 A. No. PacifiCorp provided no evidence to support that it is unable to analyze its
18 own Oregon Test Year data in regards to asking for increased amounts
19 compared to its Base Year in this rate case. The Company should be able to
20 demonstrate, with appropriate supporting evidence, the costs that are to be
21 borne by Oregon ratepayers. PacifiCorp has not met the burden of proof to
22 request additional revenue for the FERC accounts listed in Table 1.

[1] See PacifiCorp/3100, McCoy 61.

Q. Did the Company provide appropriate data, split between labor and non-labor, for SDR 058 with their initial application?

A. No. The Company provided various workbooks that were not in the format specifically requested for SDR 058.

Q. Did Staff request a supplemental filing for SDR 058?

A. Yes. As noted in the Company's Reply Testimony,[2] here is a summary of the timeline of events related to SDRs 057 and 058:

2/14/20 – The Company submits initial response to SDRs 057 and 058.

4/9/20 – Staff contacts the Company related to information provided in SDRs 057 and 058.

4/10/20 – A conference call between Staff and the Company is held to discuss the data in SDRs 057 and 058. What is not noted in the Reply Testimony is that staff specifically requested a supplemental filing for SDR 058.

4/20/20 – Staff contacted the Company about SDRs 057 and 058.

4/21/20 - A conference call between Staff and the Company is held to discuss the data in SDRs 057 and 058. Staff reiterates the requested format for SDR 058 and provides a template file as an example.

5/15/20 – The Company provides its first supplemental data for SDR 058.

Q. Did Staff issue Data Requests related to SDR 058?

A. Yes. Once the Company provided supplemental data to SDR 058, Staff was able to analyze the non-labor data provided. Staff issued DRs 571-591.

Q. Which accounts did Staff request clarification for in DRs 571-591?

[2] See PacifiCorp/3100, McCoy 58-61.

A. Staff requested additional information on the following FERC accounts for changes in the non-labor accounts:
560, 561, 570, 580, 581, 583, 587, 588, 590, 592, 593, 594, 921, 922, 924, 928, and 929.

Q. What were Staff's efforts to clarify changes in specific O&M and A&G Accounts listed above?

A. Staff asked multiple times for clarification regarding specific O&M accounts that significantly increased more than the Urban CPI index from the Base Year to the Test Year. Staff first asked using DRs 571-591 and then requested Staff's legal counsel to follow up for supplemental responses.

Q. Did PacifiCorp provide additional information?

A. No. The Company reiterated its position stated in DR 571 that, "Because these adjustments are made only at the FERC Account level, on a total basis (i.e. labor and non-labor combined), variances between Base and Test Year cannot be explained on a non-labor only basis, but is only meaningfully identifiable on a total basis by FERC Account."[3]

Q. What is Staff's position related to the accounts identified in DRs 571-591?

A. The Company did not provide any explanation for specific increases in the above identified accounts. For this reason, Staff recommends the following reductions by account:

[3] See DR 571.

Table 1		Base Year	OR 19(1/2)	OR 20	OR 21 Escalation	Test Year	Test Year vs:	Staff
Account	Non-labor	OREGON	Urb CPI	Urb CPI	Urb CPI	OREGON	Escalation	Adjustment
			1.8%	1.8%	1.7%			
570	Maintenance of Station Equipment	839,633	847,190	862,439	877,101	1,252,175	375,074	(375,074)
583	Overhead Line Expenses	60,326	60,868	61,964	63,018	357,319	294,301	(294,301)
587	Customer Installation Expenses	179,277	180,891	184,147	187,277	1,234,416	1,047,138	(1,047,138)
592	Maintenance of Station Equipment	419,197	422,970	430,583	437,903	825,379	387,476	(387,476)
594	Maintenance of Underground Lines	1,936,699	1,954,129	1,989,303	2,023,121	2,639,674	616,552	(616,552)
	Total O&M	3,435,132	3,466,048	3,528,437	3,588,420	6,308,962	2,720,541	(2,720,541)
924	Property Insurance	7,581,128	7,649,359	7,787,047	7,919,427	8,608,613	689,186	(689,186)
928	Regulatory Commission Expense	6,070,810	6,125,447	6,235,705	6,341,712	6,548,375	206,663	(206,663)
	Total A&G	13,651,938	13,774,806	14,022,752	14,261,139	15,156,988	895,849	(895,849)
	Total Adjustment							(3,616,390)

In Table 1, Staff determined the accounts that exceeded the Urban Growth CPI index, which Staff uses for escalation. Because the Base Year ended at June 30, 2019, Staff used 2.5 years of escalation to determine a Test Year amount. Staff then removed any amount from the Test Year that was above the escalated Base Year.

What is Staff's recommendation related to the accounts identified in Table 1?

A. Staff recommends a total expense reduction of $3.616M for the Test Year.

Q. Does this conclude your rebuttal testimony?

A. Yes.

CASE: UE 374
WITNESSES: RUSSELL (RUSS) BEITZEL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3000

Exhibits in Support
Of Rebuttal Testimony

July 24, 2020

OPUC Data Request 571

O&M, A&G
Please explain the $684K reduction in Test Year FERC 560 compared to the Base Year.

Response to OPUC Data Request 571

The Company recognizes the identified variance as the difference between Base Year and Test Year balances presented in the Company's response to Standard Data Request (SDR) OPUC 058. SDR OPUC 058 shows only non-labor operations and maintenance (O&M) expenses. The historical balances were derived manually, utilizing general ledger accounts to isolate the non-labor portion of expenses to the best of the Company's ability and prepared specifically in response to SDR OPUC 058. Test Year adjustments are not made at this level of detail in the general rate case (GRC). The Company's Test Year results calculated for the purpose of ratemaking in general rate cases are calculated at a functional basis, using Base Year total balances at the Federal Energy Regulatory Commission (FERC) Account level as a starting point. Each of the revenue requirement components in Base Period was analyzed to determine if a normalizing ratemaking adjustment was warranted to reflect normal operating conditions. The historical information was then adjusted to recognize known and measurable, and anticipated events. Therefore, the only variance between Base Year and Test Year balances is the regulatory adjustments. Because these adjustments are made only at the FERC Account level, on a total basis (i.e. labor and non-labor combined), variances between Base and Test Year cannot be explained on a non-labor only basis, but is only meaningfully identifiable on a total basis by FERC Account. (Note: the only adjustment in this rate case that specifically adjusts labor and labor-related costs is Adjustment 4.2, Wage and Employee Benefits. Amounts identified in Adjustment 4.2 are excluded from escalation in Adjustment 4.11, O&M Escalation.)

Please refer to Attachment OPUC 571 for a table summarizing all the Test Year regulatory adjustments accounting for the variance between Base Year and Test Year FERC Account balance for the O&M expense account in question, explaining the change from Base Year to Test Year levels as included in the Company's GRC. Each adjustment identified is supported by its individual work paper sponsored by Shelley E. McCoy. Balances in Attachment OPUC 571 are presented on an Oregon-allocated basis.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.