June 4, 2020

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Public Utility Commission of Oregon
Attn: Filing Center
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Re: Docket No. UE 374 Sierra Club Opening Testimony

Enclosed please find for filing in Docket No. UE 374 the following exhibits:

Exhibits 100-1-25: Fisher
Exhibits 200-204: Posner

Confidential and highly confidential versions of the documents herein will be serviced in accordance with OAR 860-001-0070(3) and the Commission's Covid-19 Response outlined in Order 20-088 on all eligible party representatives electronically via encrypted password protected ZIP folders

If you have any questions or require any additional information, please do not hesitate to contact me.

Respectfully submitted,



Ana Boyd
Research Analyst
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
415-977-5649
ana.boyd@sierraclub.org

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, Request for a General Rate Revision	UE 374

CERTIFICATE OF SERVICE

I hereby certify that on this 4th day of June, 2020, I have served the foregoing Opening Testimony and Exhibits of Jeremy Fisher and David B. Posner upon all party representatives on the official service list for this proceeding. The public version of this document was served upon parties via email, and the confidential and highly confidential portions of this document was served pursuant to Protective Order No. 16-128 and 20-145 respectively upon all eligible party representatives electronically via encrypted password protected ZIP folders.

PACIFICORP
Etta Lockey (C)
Matthew McVee (HC) (C)
825 NE Multnomah St, Ste 2000
Portland, OR 97232
etta.lockey@pacificorp.com
matthew.mcvee@pacificorp.com
oregondockets@pacificorp.com

STAFF
Marianne Gardner (C)
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088
marianne.gardner@state.or.us

Sommer Moser (C) (HC)
PUC Staff - Department Of Justice
1162 Court St. NE
Salem, OR 97301
sommer.moser@doj.state.or.us

Elizabeth B Uzelac (C)
PUC Staff - Department Of Justice
Business Activities Section
1162 Court St. NE
Salem, OR 97301
elizabeth.b.uzelac@state.or.us

AWEC
Brent Coleman (C) (HC)
Tyler C Pepple (C) (HC)
Davison Van Cleve, PC
1750 SW Harbor Way, Ste 450

OREGON CITIZENS UTILITY BOARD
Robert Jenks (C) (HC)
Michael Goetz (C) (HC)
610 SW Broadway, Ste 400
Portland, OR 97205

Portland, OR 97201
blc@dvclaw.com
tcp@dvclaw.com

Bradley Mullins (C) (HC)
Mountain West Analytics
1750 SW Harbor Way, Ste 450
Portland, OR 97201
brmullins@mwanalytics.com

KWUA
Klamath Water User Association
2312 South Sixth Street, Ste. A
Klamath Falls Or 97601
assist@kwua.org

Paul S Simmons
Somach Simmons & Dunn, PC
500 Capitol Mall, Ste.1000
Sacramento, CA 95814
psimmons@somachlaw.com

CALPINE SOLUTIONS
Greg Bass
401 West A St., Ste. 500
San Diego, CA 92101
greg.bass@calpinesolutions.com

Gregory M. Adams (C)
Richardson Adams, PLLC
P.O. Box 7218
Boise, ID 83702
greg@richardsonadams.com

bob@oregoncub.org
mike@oregoncub.org
dockets@oregoncub.org

TESLA INC
Bill Ehrlich (C) (HC)
3500 Deer Creek Rd
Palo Alto Ca 94304
wehrlich@tesla.com

Francesca Wahl (C) (HC)
6800 Dumbarton Circle
Fremont, CA 94555
fwahl@tesla.com

Kevin Auerbacher (C) (HC)
601 13th St NW, 9th Fl North
Washington, DC 20005
kauerbacher@tesla.com

John Dunbar (C) (HC)
Dunbar Law LLC
621 SW Morrison St, Ste 1025
Portland, OR 97205
jdunbar@dunbarlawllc.com

VITESSE LLC
R. Bryce Dalley (C)
Facebook, Inc.
24005 Bertsinger Rd.
Ridgefield, WA 98642
rbd@fb.com

Liz Ferrell (C)
Facebook, Inc.
1 Hacker Way
Menlo Park, CA 94205
eferrell@fb.com

Kevin Higgins (C)
Energy Strategies LLC
215 State St, St 200
Salt Lake City, UT 84111-2322
khiggins@energystrat.com

CHARGEPOINT INC
Steve Elzinga (C)
Alexandra Leumer (C)
693 Chemeketa St NE
Salem, OR 97301
steve@shermlaw.com
alexandra.leumer@chargepoint.com

Scott Dunbar (C)
Keyes Fox & Wiedman LLP
1580 Lincoln St, Ste 880
Denver, CO 80203
sdunbar@kfwlaw.com

SBUA
Diane Henkels (C)
Adleaide "Ellie" Hardwick
621 SW Morrison St, Ste 1025
Portland, OR 97205
diane@utilityadvocates.org
adelaide@utilityadvocates.org

James Birkelund (C)
548 Market St, Ste 11200
San Francisco, CA 94104
james@utilityadvocates.org

William Steele (C)
Bill Steele And Associates, LLP
PO Box 631151
Highlands Ranch, CO 80164
wa.steele@hotmail.com

Irion A Sanger (C)
Sanger Law PC
1041 SE 58th Place
Portland, OR 97215
irion@sanger-law.com

WALMART
Steve W Chriss (C)
2001 SE 10th St
Bentonville, AR 72716-0550
stephen.chriss@wal-mart.com

Vicki M Baldwin (C)
Parsons Behle & Latimer
201 S Main St, Ste 1800
Salt Lake City, UT 84111
vbaldwin@parsonsbehle.com

FRED MEYER
Justin Bieber (C)
215 South State Street, Ste 200
Salt Lake City, UT 84111
jbieber@energystrat.com

Kurt J Boehm (C)
Jody Kyler Cohn (C)
Boehm Kurtz & Lowry
36 E Seventh St, Ste 1510
Cincinnati, OH 45202
kboehm@bkllawfirm.com
jkylercohn@bkllawfirm.com

Dated this 4th day of June, 2020 at Redwood City, CA.

/s/ Ana Boyd

Ana Boyd
Research Analyst
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
ana.boyd@sierraclub.org

BEFORE THE
OREGON PUBLIC UTILITIES COMMISSION

In the Matter of PACIFICORP d/b/a PACIFIC POWER Request for a General Rate Revision.	**UE 374**

Opening Testimony of
Jeremy Fisher, PhD

On Behalf of
Sierra Club

Redacted Version

June 4, 2020

TABLE OF CONTENTS

1. Introduction and Qualifications 1

2. Summary of Conclusions and Recommendations 4

3. The Company's Election to Install Selective Catalytic Reduction at Jim Bridger in December 2013 was Imprudent 8

   a. Overview of PacifiCorp's Jim Bridger 3 & 4 SCR Assessment 11

   b. The Timeline to Install SCR at Jim Bridger by 2015 and 2016 was of the Company's Own Manufacture 17

   c. The Company's Assessed Alternatives to Constructing SCRs at Jim Bridger was Fundamentally Faulty 28

   d. Costs and Operations at the Bridger Mine Changed Materially in the Months Prior to the FNTP 32

   e. Gas Prices Fell Rapidly in the Months Leading Up to the FNTP 44

   f. The Liability of the Jim Bridger SCRs Exceeded the Cost of Contract Termination Well Before the project Reached Completion 58

   g. The Continued Operations of Jim Bridger Have Imposed Substantial and continuing Harm on PacifiCorp's Ratepayers 62

4. PacifiCorp's election to allow environmental retrofits at Hayden was inconsistent with its own assessments 66

   a. PacifiCorp's Flawed Assessment of the [redacted] at Hayden 79

   b. PacifiCorp's Flawed Assessment of its [redacted] for the SCRs at Hayden 81

LIST OF FIGURES

Confidential Figure 1. Relationship between levelized gas prices and the (benefit) / cost of the SCR investments at Jim Bridger 3 & 4. 14

Confidential Figure 2. Benefit of SCRs at Bridger 3&4 over time, Company and Author calculations 15

Figure 3. Figure from PacifiCorp 2010 Plan, showing capital expenditures anticipated at PacifiCorp's coal plants. 22

Figure 4. Deliveries of coal to Jim Bridger plant (M tons). 33

Confidential Figure 5. Baseline total cost of coal at Bridger Coal Company surface and underground mines from January 2013, four unit scenario ($/MMBtu) 40

Figure 6. PacifiCorp projections of Opal gas prices Dec 2011- Dec 2013 (blue) and 2014-2016) 47

Figure 7. NYMEX Futures for 2018 HH, 2012-2016, indicating fall in forecast during 2013. 49

Figure 8. PacifiCorp slide on Forward Price Curves. October 29, 2013. 51

Highly Confidential Figure 9. SCR contractor associated cancelation schedule (i.e. [redacted]) versus the value of the Bridger SCR projects from December 2013 (including adjustment for coal and SCR cost savings) through the completion of the project. 60

Figure 10. Table from PSCo Emission Reduction Plan scenarios before the CoPUC, showing the assumption that Hayden would be retrofit with SCR in each scenario. 71

Confidential Figure 11. November 2012 Assessment of Hayden and Craig value, as conducted by PacifiCorp, and as corrected. 86

LIST OF EXHIBITS

Sierra Club/101	Curriculum Vitae of Jeremy Fisher, PhD
Sierra Club/102	Public Discovery Responses
Sierra Club/103	Confidential Direct Testimony of Rick Link in 20000-418-EA-12 (Wyo. Pub. Serv. Comm'n) (provided as an attachment to PacifiCorp Response to Sierra Club Data Request 1.1)
Sierra Club/104	Redacted Rebuttal Testimony of Rick Link in 20000-418-EA-12 (Wyo. Pub. Serv. Comm'n)
Sierra Club/105	WY DEQ Bart Appeal Settlement Agreement (November 2010)
Sierra Club/106	PacifiCorp Emission Reduction Plan (Nov. 2, 2010)
Sierra Club/107	PacifiCorp Comments on WY Regional Haze Plan (Aug. 26, 2013) (excerpt)
Sierra Club/108	Confidential Rebuttal Testimony of Dana Ralston in UE-152253 (Wash. Util. & Transp. Comm'n) (provided as an attachment to PacifiCorp Response to Sierra Club Data Request 1.8(c))
Sierra Club/109	Redacted Supplemental Rebuttal Testimony of Cindy A. Crane in UE-152253 (Wash. Util. & Transp. Comm'n)
Sierra Club/110	PacifiCorp Response to Sierra Club Data Request 4.9 in Docket No. 13-035-184 (Utah Pub. Serv. Comm'n)
Sierra Club/111	Hearing Transcript of Ms. Cindy Crane in Docket No. 20000-418-EA-12 (Wyo. Pub. Serv. Comm'n)
Sierra Club/112	"Attach Sierra Club 3.27" in Docket No. LC 70
Sierra Club/113	Andrew Graham, *Life beneath the earth in Wyo's only underground coal mine*
Sierra Club/114	Supplemental Testimony of Jeremy Twitchell in Docket No. UE-152253 (Wash. Util. & Transp. Comm'n)
Sierra Club/115	Confidential Attachment 1.5-2 to PacifiCorp Response to Sierra Club Data Request
Sierra Club/116	PacifiCorp, *2012 Natural Gas Request for Proposals Workshop* (Oct. 29, 2013)

LIST OF EXHIBITS CONT.

Sierra Club/117	PacifiCorp Response to Sierra Club Data Request 4.10 in Docket No. 13-035-184 (Utah Pub. Serv. Comm'n)
Sierra Club/118	PacifiCorp Dec. 5, 2013 Memorandum (provided as a confidential attachment to PacifiCorp Response to Sierra Club Data Request 1.4)
Sierra Club/119	Highly Confidential Exhibit B Re: Bridger EPC Contract
Sierra Club/120	Direct Testimony of Susan Arigoni in Docket No. 11A-917E (Colo. Pub. Util. Comm'n)
Sierra Club/121	Confidential Technical Workshop: Review of Existing Analysis on Craig and Hayden Environmental Investments (provided as a confidential attachment to PacifiCorp Response to Sierra Club 2.6)
Sierra Club/122	Confidential Attachment to Pacificorp Response to Sierra Club Data Request 2.6-2 (Hayden PVRR)
Sierra Club/123	Confidential Hayden SCR Recommendation Memo (provided as a confidential attachment to PacifiCorp Response to Sierra Club Data Request 2.4)
Sierra Club/124	Confidential Attachment to Pacificorp Response to Sierra Club Data Request 2.4 (Xcel Energy Projects)
Sierra Club/125	Direct Testimony of James Hill in Docket No. 10M-245E (Colo. Pub. Util. Comm’n)

1. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, position, and business address.

A My name is Jeremy I. Fisher. I am a Senior Advisor for Strategic Research and Development in Sierra Club's Environmental Law Program, which is located at 2101 Webster Street, Suite 1300 in Oakland, California.

Q On whose behalf are you providing testimony in this case?

A I am providing testimony on behalf of Sierra Club.

Q Please describe your role at Sierra Club.

A Sierra Club is a national public interest group dedicated to the responsible use of ecosystems and resources with over 800,000 members. My role as an advisor is to work with the Environmental Law Program to understand and engage productively with best utility practices in energy system planning, fossil generation issues, energy efficiency and renewable energy, ratemaking and rate design, market power issues, and utility regulations.

Q Please summarize your work experience and educational background.

A Prior to joining Sierra Club in December 2017, I held the position of Principal Associate with Synapse Energy Economics in Cambridge, Massachusetts where I worked for a decade on electricity system energy planning, supporting regulators in the use and execution of environmental regulations, and helping states craft or revise resource planning rules. As a consultant, I worked with a wide variety of public sector and public interest clients, including the U.S. Environmental

Protection Agency ("EPA"), the National Association of Regulatory Utility Commissioners ("NARUC"), the National Association of State Utility Consumer Advocates ("NASUCA"), National Rural Electric Cooperative Association ("NRECA"), the energy offices and public utility commissions of Alaska, Arkansas, Michigan, and Utah, the Commonwealth of Puerto Rico, Tennessee Valley Authority Office of Inspector General ("TVA OIG"), the California Division of Ratepayer Advocates ("CADRA"), the California Energy Commission ("CEC"), the Regulatory Assistance Project ("RAP"), and multiple environmental public interest groups. In 2014 and 2015, I provided training to federal regulators on resource planning practice. I recently led an intensive statewide planning process on behalf of the Michigan Public Service Commission ("MPSC") and worked on behalf of the Puerto Rico Energy Commission ("CEPR") on the first open audit of the Commonwealth's public utility.

I have provided testimony in electricity planning and general rate case dockets in California, Georgia, Idaho, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Nevada, New Mexico, Ohio, Oklahoma, Oregon, Puerto Rico, Utah, Washington, Wisconsin, and Wyoming.

I hold a doctorate in Geological Sciences from Brown University, and I received my bachelor degrees from University of Maryland in Geology and Geography.

My full curriculum vitae is attached as Exhibit Sierra Club/101.

Q Have you previously provided comments to or testified before the Oregon Public Utility Commission previously?

A Yes. I've submitted testimony on behalf of Sierra Club in PacifiCorp's prior rate case in 2012 (OR UE 246), and supported Sierra Club comments in multiple PacifiCorp IRP proceedings from 2013 to the present day.

Q In general, are you familiar with PacifiCorp's system and practices?

A Yes. Since 2010, I've reviewed PacifiCorp's long-term resource planning and short-term modeling in dockets across the Company's service territory. This includes expert testimony in rate cases (WY 20000-384-ER-10, WY 20000-446-ER-14, OR UE 246, WA UE-152253), certificates of public convenience and necessity ("CPCN") (WY 20000-418-EA-12), assessments of fuel contracts (OR UM 1712, CA A.15-09-007), and multiple integrated resource planning ("IRP") reviews in 2013 (OR LC 57, UT 13-2035-01), 2015 (OR LC-62, UT 15-035-04), 2017 (OR LC-67, UT 17-035-16), and 2019 (OR LC 70, UT 19-035-02).

Q What is the purpose of your testimony?

A My testimony is focused on the election of PacifiCorp d.b.a. Pacific Power ("Company") to install high-cost selective catalytic reduction ("SCR") emissions controls at the Jim Bridger units 3 & 4 and Hayden 1 & 2 coal-fired power stations. My testimony walks through the process of how PacifiCorp, or in the case of Hayden, its co-owner Public Service Company of Colorado ("PSCo"), decided to move forward with the retrofits, and the analyses that PacifiCorp

employed to assess whether the retrofits were in the best interests of customers. I assess the alternatives available to the Company at each key decision-making moment, and how the Company's decisions aligned with the information it knew, or should have known at the moment.

I show that the Company understood that its election to move forward with the SCRs at Jim Bridger 3 & 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. Once the Company began construction, the liability of the project degraded faster than the monies the Company sank into it, meaning ratepayers would have benefited from cancelation mid-stream.

I also show that the Company failed to conduct appropriate due diligence on the Hayden SCR projects when decisions on those projects were underway by PSCo, and then failed to appropriately exercise its participation rights when it determined that the projects were not favorable to ratepayers.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Can you summarize your conclusions?

A Yes. With respect to the installation of SCR at Jim Bridger 3 & 4, I conclude the following:

1. PacifiCorp manufactured a compliance deadline that it understood was well ahead of EPA's requirements;

2. PacifiCorp asserted that same compliance deadline without respect to alternatives or the flexibility afforded under the Clean Air Act, at a cost to ratepayers;
3. PacifiCorp's election to move forward on the SCRs at Jim Bridger 3 & 4 on December 1, 2013 was uninformed by changes in the projected cost of coal and gas available to the Company, factors which would have shown a substantially degraded value for the projects.
4. A new mining plan in October 2013 materially changed the way that PacifiCorp would procure coal for Jim Bridger, and increased the cost of coal, and yet PacifiCorp failed to assess how that plan would impact its impending SCR decision.
5. PacifiCorp failed to assess new market price projections available to it prior to December 1, 2013 that would have revealed lower market price forwards for gas.
6. PacifiCorp's use of a shortcut "breakeven" assessment to determine whether the SCR still had economic value in September 2013 relied on modeling data over 15 months old, and was unbefitting of a project of this magnitude.
7. Prior to committing monies to the SCR projects at Jim Bridger, the Company was aware that the economic value of the projects had degraded substantially, and yet failed to conduct more extensive modeling.
8. After committing monies to the SCR projects on December 1, 2013, the Company failed to assess whether continuing with the projects was cost effective or in the best interests of customers.

9. The Company failed to terminate the SCR projects when the forward liability of continuing the projects and operating Jim Bridger 3 & 4 on coal fell below the cost of ceasing construction.
10. PacifiCorp's election to install SCRs in December 2013 and continue operating Jim Bridger 3 & 4 has resulted in excess costs to ratepayers above the cost of alternatives. Ratepayers have incurred damages more substantial than the cost of the SCRs alone.

With respect to the installation of SCRs at Hayden 1 & 2, I conclude the following:

1. The Company failed to engage successfully or meaningfully in PSCo's 2010 emission reduction plan, whereby PSCo opted to install SCRs at Hayden, committing PacifiCorp to that same course of action.
2. The Company failed to assess the joint cost of signing a new coal contract for Hayden and moving forward on the SCRs. By decoupling the SCR decision from the coal contract decision, the Company made two separate elections that should have been made jointly.
3. The Company 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. The Company failed to pursue an alternative retirement strategy with PSCo, instead incorrectly agreeing to—[redacted]—an unenforceable premature compliance deadline.

5. The Company's assessment of [redacted] but the Company elected to ignore this information and signaled its approval to PSCo.

6. [redacted].

7. [redacted]

8. [redacted].

[redacted]

Q What are your recommendations to this Commission?

A With respect to the SCRs at Jim Bridger, I recommend that the Commission disallow the full costs of the projects, [redacted] on an Oregon-allocated basis.

With respect to the SCRs at Hayden, I recommend that the Commission disallow the full costs of the projects, [redacted] on an Oregon-allocated basis.

In addition, I recommend that the Commission consider disallowing costs associated with the [redacted] Hayden coal contract entered into in 2011.

3. THE COMPANY'S ELECTION TO INSTALL SELECTIVE CATALYTIC REDUCTION AT JIM BRIDGER IN DECEMBER 2013 WAS IMPRUDENT

Q Please describe the Jim Bridger plant.

A The Jim Bridger power plant is a 2,100 MW coal-fired plant made up of four units (Jim Bridger units 1, 2, 3, and 4). PacifiCorp owns two-thirds of each unit and Idaho Power Company owns the remaining one-third. Jim Bridger is located in southwest Wyoming and contributes to haze pollution in several national parks and wilderness areas: Yellowstone National Park, Grand Teton National Park, Rocky Mountain National Park, Teton Wilderness Area, Bridger Wilderness Area, Fitzpatrick Wilderness Area, Mt Zirkel Wilderness Area, Rawah Wilderness Area, and Washakie Wilderness Area. [1]

Jim Bridger is a mine-mouth plant, which means that it receives the bulk of its coal fuel from a mine that is adjacent to (or at least near) the plant. The majority of Jim Bridger plant ("Bridger plant") is supplied by the Bridger coal mine ("Bridger mine"). The Bridger mine is comprised of two separate operations—a surface mine and an underground mine, a distinction which will prove important.

The Bridger mine is operated by the Bridger Coal Company ("BCC"), itself a jointly-owned subsidiary of PacifiCorp and Idaho Power Company. Bridger Coal Company is one of the few remaining coal mining operations owned by a regulated utility. The costs of operating BCC are recovered both through the fuel costs of Jim Bridger plant, as well as recovered directly through rate base from

[1] Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 79 Fed. Reg. 5032, 5041 (Jan. 30, 2014).

PacifiCorp's customers. This intimate relationship between the mine and the plant, and the fact that both are rate-based means that PacifiCorp treats the mine as an asset for which customers maintain all liability. Similarly, factors that affect the mine impact the costs of operating the plant, and vise versa.

Q Why did PacifiCorp install SCRs at Jim Bridger 3 & 4?

A PacifiCorp installed the selective catalytic reductions ("SCR") in connection with the Regional Haze Rule under the Federal Clean Air Act. As I will discuss later, a core question for this Commission is whether PacifiCorp actually had an enforceable obligation to install the SCRs by 2015 and 2016. In Section 3.b (page 17), I assert that the Company's timeline for the installation of SCRs was a product of its own manufacture, and was not a matter of law.

Q When did PacifiCorp decide to install SCRs at Jim Bridger 3 & 4?

A The Company agreed to install SCR at Jim Bridger 3 & 4 in November 2010, as an outcome of a settlement with the Wyoming Department of Environmental Quality ("WYDEQ").[2] As I describe below in Section 3.b, the Company appears to have entered into that agreement voluntarily, even when offered the opportunity to extend its compliance deadlines by the United States Environmental Protection Agency ("EPA").

The Company's "final" decision to proceed on the SCRs came when the Company issued a full notice to proceed ("FNTP") letter to its Engineering,

[2] PAC/800 at Teply/32:1, Figure 1—Bridger SCRs Timeline.

Procurement and Construction ("EPC") contractors on December 1, 2013.[3] Prior to signing that FNTP, the Company had the option to withdraw from the project with relatively little consequence and cost. As I show, after that contract date the Company still had the option to terminate the contract, but the cost of doing so rose thereafter. The Company had an obligation to continue assessing its decision to install the SCRs up through the signing of the FNTP on December 1, 2013, and had a continuing obligation thereafter to continue assessing if the project had merit, net of costs already sunk into the project.

Q Were alternative compliance paths available to the Company?

A Yes. The Regional Haze Rule's requirements are based on both a control technology and an emissions limit at each unit. PacifiCorp could therefore have complied with the rule either by installing the required pollution controls necessary to meet that limit, or by shutting down, or by converting the Jim Bridger units to run on fossil gas. There are several examples of coal plants shutting down or switching to gas fuel as an alternative compliance path under the Regional Haze Rule,[4] and examples wherein a unit committed to a firm future shut down date in exchange for less expensive near-term controls.[5]

[3] *Id*.
[4] Approval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Reconsideration 80 Fed. Reg. 19,220 (Apr. 10, 2015 (Apache Unit 2); 79 Fed. Reg. at 5045 (Naughton Unit 3, Wyoming; (Muskogee 4 & 5, Oklahoma).
[5] Approval and Promulgation of Implementation Plans; State of Oregon; Regional Haze State Implementation Plan and Interstate Transport Plan, 76 Fed. Reg. 38, 997 and 2008 Oregon Regional Haze Plan at 154-156 and) (PGE Boardman, Oregon); Transalta Centralia, Washington (Washington Department of Ecology, Order 6426, 2011)

Q Did the Company assess alternatives to the installation of the SCRs at Jim Bridger?

A Just one. The Company performed an assessment, described by Mr. Rick Link, to determine if it was more cost effective to install the SCRs, shut down or repower Jim Bridger 3 & 4 with gas.[6]

Notably, the Company had other forms of compliance that would have likely been deemed acceptable by EPA, and that the Company has since sought to exercise elsewhere. Prominent amongst these alternatives is the option to avoid costly controls like SCR by committing to a shorter plant life. That shorter plant life need not be the immediate shut down of the unit on the compliance deadline. I discuss alternative compliance with the Regional Haze Rule in Section 3.c (page 28), below.

a. OVERVIEW OF PACIFICORP'S JIM BRIDGER 3 & 4 SCR ASSESSMENT

Q Please summarize the Company's analysis process to determine if the SCRs should be built at Bridger 3 & 4.

A Since 2012, PacifiCorp has used the System Optimizer (sometimes abbreviated "SO") model, its primary forward planning and integrated resource planning platform, to determine whether large capital investments were economic at existing coal-fired units. PacifiCorp typically uses the model to assess two alternative worlds: one in which the retrofit is pursued, the other in which the plant is retired or, as in this case, repowered. The use of a system-wide model is critical because it assesses how other factors on the utility's system change in

[6] PAC/700 at Link/86: 8-11.

response to a retire/retrofit decision, and not just the costs of the power plant itself.

This methodology, like all other models, is highly sensitive to inputs and the quality of the data used in the model. Specifically, the value of pursuing a retrofit can change substantially as the market shifts, and decisions need to be evaluated using the very best information available up to the moment the decision is finalized, and even beyond.

The Company's initial filing in this case was a CPCN submitted to the Wyoming Public Service Commission on August 1, 2012, and was based on an analysis conducted using data from December 2011.[7] In that initial analysis, the Company claimed that the Bridger 3 & 4 SCRs had a value of [redacted][8] Intervenors pointed out that, amongst other flaws, PacifiCorp's initial analysis used outdated data. On rebuttal, filed March 4, 2013, the Company provided an updated analysis, populated with September 2012 data, showing a $183 million value,[9] substantially lower than the Company's initial valuation. The results of that

[7] PacifiCorp Response to Sierra Club Data Request 1.1(h) ("Yes, the CPCN application in Wyoming (Docket 20000-418-EA-12) used the December 2011 official forward price curve for the base case."). All public data responses referenced in this testimony are compiled and attached as Exhibit Sierra Club/102.
[8] Direct Testimony of Mr. Rick Link, *In The Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 And 4 Located Near Point of Rocks, Wyoming* Docket No.20000-418-EA-12 at 2:5. (Wyo. Pub. Serv. Comm'n Aug. 2012) (provided as an attachment to PacifiCorp Response to Sierra Club Data Request 1.1(g)) (attached as Exhibit Sierra Club/103).
[9] Redacted Rebuttal Testimony of Mr. Rick Link, *In The Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 And 4 Located Near Point of Rocks, Wyoming* Docket No.20000-418-EA-12 at 1:22. (Wyo. Pub. Serv. Comm'n Mar. 2013) (attached as Exhibit Sierra Club/104). Note that value is provided publicly in PAC/700, Link/86:15.

revised September 2012 analysis are before this commission today.[10] The Wyoming Commission docket was concluded in May 2013.

The Company's "final" assessment conducted for the Wyoming CPCN rebuttal used September 2012 data, and was conducted in January 2013[11]—it would be the last time the Company ran the System Optimizer model to assess the retire/retrofit decision.

Q How did the Company assess the value of the retire/retrofit decision after January 2013?

A Mr. Link ran what he describes as a "breakeven" assessment of the retrofit.[12] Basically, the Company observed that the value of the retrofit decision appeared to have a roughly[13] linear relationship with gas prices, and assessed that if the levelized cost of gas fell below $4.86/MMBtu, it would be more economical to repower Jim Bridger with gas than install the SCRs.

Confidential Figure 1, below, shows Mr. Link's derived relationship between the value of the SCR retrofit[14] relative to the levelized cost of gas from 2016-2030. It then shows how the value of the Bridger SCR degraded from September 2012 through December 2014 as gas prices rapidly approached and then fell below PacifiCorp's own breakeven at $4.86/MMBtu.

[10] PAC/700, Link/86:15, Link/98:9.
[11] Date stamps on Mr. Link's System Optimizer work papers submitted in this docket.
[12] PAC/700 at Link/106:4-21
[13] Roughly: Mr. Link's breakeven analysis relies on three data points to create a line of best fit. While the trend appears visually clear, from a statistical standpoint, the lack of additional modeling observations (i.e. degrees of freedom) actually renders this a weak relationship. At a 90% confidence interval, the projected "breakeven" could be as low as $3.71/MMBtu, or as high as $5.59/MMBtu.
[14] Negative values being a benefit to the Bridger SCR decision.

Confidential Figure 1. Relationship between levelized gas prices and the (benefit) / cost of the SCR investments at Jim Bridger 3 & 4.[15]



Q How had the Company's analysis of the Bridger 3 & 4 SCRs changed from the Company's CPCN proceeding in Wyoming until the time that the SCR FNTP was signed in December 2013?

A From the time the Company completed its rebuttal assessment in the Wyoming CPCN, the value of the decision to install SCRs continued to fall substantially up through the FNTP. Confidential Figure 2, below, shows the value of the Bridger 3 & 4 retrofit through time leading up to the FNTP.

[15] PAC/710; Attachment to PacifiCorp Response to Sierra Club Data Request "Attach Sierra Club 1.6.xlsx" [hereinafter "Attach Sierra Club 1.6.xlsx"] (additional OFPC author's calculation).

Confidential Figure 2. Benefit of SCRs at Bridger 3&4 over time, Company and Author calculations[16]



In the instant docket, Mr. Link testified that prior to executing the FNTP in December 2013, he found that the margin had shrunk another 30% to $130 million using September 2013 gas price projections in his breakeven assessment.[17]

However, Mr. Link's updated analysis is still deficient because it relied on inadequate and stale data when there was substantial evidence that the decision to install SCR continued to rapidly lose value. In fact, by the time PacifiCorp executed the FNTP on December 1, 2013, the SCR projects had effectively no value to ratepayers.

As I show in Section 3.d (page 32), PacifiCorp acknowledged that the costs of coal provided to Jim Bridger had increased in October 2013, reducing the value to

[16] [A] Ex. Sierra Club/103, Direct Testimony of Rick Link in Wyoming 20000-418-EA 12 at 2:5; [B] PAC/700 at Link/86:15; [C] PAC/700 at Link/107:13; [D] Author's calculation, see Adjustment #1; [E] Author's calculation, see Adjustment #2.
[17] PAC/700 at Link/107:13

[redacted]—an adjustment neither disclosed nor discussed by Mr. Link. Below, I show that the Company critically failed to assess how a new mine operations plan for Jim Bridger would impair the decision to retrofit Jim Bridger 3 & 4.

Finally, late 2013 was the dawn of the hydraulic fracturing boom, and in the months leading up to the FNTP, analysts and PacifiCorp were projecting substantially lower forward-looking gas prices. As I describe in Section 3.e (page 44) information in the Company's hands prior to the execution of the FTNP led the Company to conclude that gas prices had fallen within cents of Mr. Link's $4.86/MMBtu breakeven,[18] and a reasonable assessment of trends leading up to that period would have concluded that there was a very real potential that the project would fail economically. In December 2013, the value of the SCR retrofit had, conservatively, fallen to [redacted]—effectively a wash.

As has been made clear in the industry, the economics of maintaining coal have continued to fall drastically in the months and years since the Company finalized its decision to proceed with the SCRs, to the extent that the Company recently identified Jim Bridger 3 & 4 as candidates for early retirement in the 2019 IRP.

Finally, as I show in Section 3.f (page 58) the Company's own metric for the economics of the Bridger 3 & 4 SCRs degraded so rapidly that the losses attributed to the continued operations of the unit exceeded the termination cost of the SCR project during the construction of the SCRs. In other words, the Company erred not only in releasing contractors to build the SCRs, but it also

[18] PAC/700 at Link/101:13-17.

erred in not re-evaluating—and ceasing construction—at the Bridger SCRs, to the detriment of their ratepayers.

b. THE TIMELINE TO INSTALL SCR AT JIM BRIDGER BY 2015 AND 2016 WAS OF THE COMPANY'S OWN MANUFACTURE

Q What is the basis for the SCRs at Jim Bridger, and how is the installation connected to the Clean Air Act?

A Regional haze results from small particles in the atmosphere that impair a viewer's ability to see long distances and color. The main haze-forming pollutants are sulfur dioxide (SO_2), nitrogen oxides (NO_X) and fine particulate matter (PM). These air pollutants contribute to the deterioration of air quality and reduced visibility in our national parks and wilderness areas, designated as Class 1 areas.

In 1977, Congress declared as the nation's 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 manmade air pollution."[19] In order to meet this goal, states are required to adopt implementation plans ("SIPs") to reduce, and ultimately eliminate, haze-causing pollution that may cause or contribute to visibility impairment for any protected Class 1 area (i.e. wilderness or national park) located within or beyond that state's boundaries.

The Clean Air Act imposes a legal obligation on both states and EPA to abate haze pollution in such Class 1 areas.[20] One of the Clean Air Act's mechanisms for achieving this goal was the requirement for certain haze-causing sources, like coal

[19] 42 U.S.C. §7491(a)(1).
[20] *Id.*

plants, to install "best available retrofit technology" ("BART").[21] Bridger units 3 & 4 were subject to BART.

Under the BART-phase of the Regional Haze Rule, states were required to assess which power plants were covered by the rule, and set emissions limits and require control technology necessary to satisfy the particular requirements of BART, including visibility monitoring and an assessment of cost. States would then include these findings into a SIP, which would be submitted to EPA for final approval. EPA had the option of approving, disapproving, or modifying state plans. If EPA disapproved a plan (or a portion of a plan), it then promulgated a federal implementation plan ("FIP") to replace the disapproved SIP.[22] Ultimately regional haze plans were not enforceable until after EPA acted to either approve a SIP or issue a FIP. Finally, under the Regional Haze Rule, an owner/operator was required to comply with a final BART rule within five years of rule issuance.[23]

In 2011, Wyoming Department of Environmental Quality ("WYDEQ") submitted a revised state implementation plan to EPA to comply with the BART provisions of the Regional Haze Rule. Within that SIP, the state proposed that Jim Bridger 3 & 4 be retrofit with SCRs in 2015 and 2016, respectively. After several years of back and forth, EPA disapproved several elements of Wyoming's plan, which triggered EPA's obligation to promulgate a federal implementation plan ("FIP") to replace those disapproved elements.[24]

[21] *Id*. §§ 7491(a), (b)(2).
[22] 42 U.S.C. § 7410(c)(1)(A).
[23] 40 C.F.R. 51.308(e)(iv).
[24] 79 Fed. Reg. 5032 (Jan. 30, 2014).

EPA issued a FIP, which then became binding on Jim Bridger, on January 30, 2014[25]—nearly two months after the Company had already issued its FNTP for the SCRs at Jim Bridger. In other words, the Company made its final determination to proceed with the retrofit before the EPA had finalized the plant's BART obligations.

Q Did the Company decide to install SCRs at Jim Bridger in 2015/2016 before EPA had even finalized its requirements?

A Yes. In 2007, PacifiCorp provided data to Wyoming for Wyoming to incorporate into its regional haze SIP. Wyoming adopted that first regional haze SIP on May 22, 2008,[26] followed by a series of permit issuances from Wyoming DEQ authorizing PacifiCorp to move forward with SCRs.

On November 2, 2010, PacifiCorp settled with WYDEQ, agreeing not to appeal the SCR requirements for a number of coal units.[27] In the settlement, PacifiCorp agreed to install SCR at Jim Bridger 3 & 4 by 2015 and 2016, and install SCR at Jim Bridger 1 & 2 by 2022 and 2021, respectively. The settlement, which is briefly mentioned by Mr. Teply as the "2010 Wyoming Stipulation",[28] was signed by PacifiCorp's then Vice President of Generation, Dana Ralston.

In January 2011, WYDEQ submitted a revised SIP to EPA, including the proposed settlement terms. Importantly, EPA did not make its final BART

[25] PAC/800 at Teply/32:1, Figure 1—Bridger SCR Timeline.
[26] *Id.*
[27] Exhibit RMP_(CSW-3R) Accompanying the Rebuttal Testimony of Cathy S. Woollums, November 2010 Wyoming DEQ Bart Appeal Settlement Agreement, Docket No. 20000-418-EA-12 (Wyo. Pub. Serv. Comm' March, 2013) (attached as Exhibit Sierra Club/105).
[28] PAC/800 at Teply/28:10-11.

determination for Wyoming until January 30, 2014. In its FIP, EPA was explicit that while it was accepting Wyoming's proposed deadlines, compliance was only required "within five years of our approval of the SIP,"[29] pushing PacifiCorp's deadline out to 2019. EPA noted that it was accepting the state's deadlines because they were likely more stringent than what the EPA itself would have otherwise required:

> In our proposal, we indicated that the State had neglected to reasonably assess the costs of compliance and visibility improvement for Jim Bridger in accordance with the BART Guidelines. We nonetheless proposed to approve the State's BART and reasonable progress determinations for Units 3 and 4 because the compliance deadlines to install SCR on these units were sufficient to meet the requirements of BART.[30]

The Regional Haze rule provided up to five years to install BART retrofits.[31] In this case, however, PacifiCorp appears to have supported—or likely proposed—the 2015/2016 installation dates for Bridger 3 and 4 back in November 2010, as I describe below.

Q To date, what had been the typical EPA-mandated compliance period for installing BART retrofits?

A The Regional Haze rule expressly provides owners/operators with a five-year installation window. In this case, EPA finalized its FIP for Wyoming on January 30, 2014 with an effective date of March 3, 2014. Therefore, **the Jim Bridger 3 & 4 projects would have had a compliance deadline of March 2019**, not 2015 and 2016. EPA only affirmed Wyoming's proposed 2015/2016 compliance

[29] 79 Fed. Reg. at 5046.
[30] *Id.*at 5048.
[31] 40 C.F.R. 51.308(e)(iv).

deadlines because PacifiCorp had agreed to or proposed those deadlines itself. In no instance did PacifiCorp complain about the expedited construction schedule.

Q Why was the Company's rush to achieve early compliance with the Regional Haze Rule a problem in this case?

A The Company's rush to achieve early compliance with an expensive environmental obligation deeply reduced the Company's optionality. By pushing forward to meet compliance well ahead of the federally mandated deadline—in this case by a number of years—the Company forfeited any opportunity to assess whether the expedited compliance schedule was economically advantageous for its customers.

Q Why did PacifiCorp support the 2015/2016 SCR installations at Jim Bridger plant?

A The record convincingly indicates that PacifiCorp viewed the installations as a way of extending investments in its coal plants, and identified from an early date the opportunity to invest $2.7 billion dollars across its entire coal fleet.

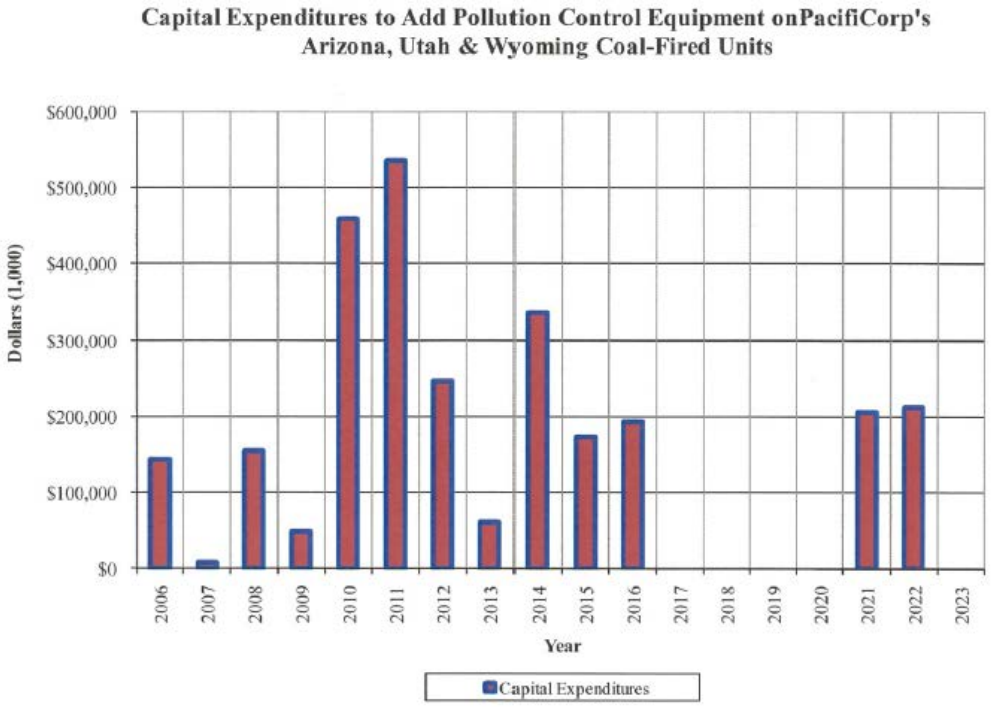
On November 2, 2010—the same day that PacifiCorp settled with WYDEQ, according to Mr. Teply's testimony[32]—PacifiCorp provided to Wyoming an Emissions Reduction Plan ("2010 Plan").[33] The 2010 Plan opened with a description of the monies PacifiCorp anticipated spending:

[32] PAC/800 at Teply/32:1, Figure 1—Bridger SCR Timeline.
[33] Exhibit A: PacifiCorp's Emission Reduction Plan (Nov. 2, 2010) (originally published as part of Regional Haze State Implementation Plan supporting materials at WYDEQ) (attached as Exhibit Sierra Club/106).

> From 2005 through 2010 PacifiCorp has spent more than $1.2 billion in capital dollars [on emission reductions]. **It is anticipated that the total costs for all projects that have been committed to will exceed $2.7 billion by the end of 2022.** The total costs (which include capital, O&M and other costs) that will have been incurred by customers to pay for these pollution control projects during the period 2005 through 2023, are expected to exceed $4.2 billion, and by 2023 the annual costs to customers for these projects will have reached $360 million per year.[34]

The 2010 Plan then showed a schedule of prior and anticipated spending, including the substantial spending for the Bridger 3 & 4 SCRs in 2015 and 2016, and the Bridger 1 & 2 SCRs in 2021 and 2022.

Figure 3. Figure from PacifiCorp 2010 Plan, showing capital expenditures anticipated at PacifiCorp's coal plants.[35]



[34] *Id*. at 1 (emphasis added).
[35] *Id*. at 5.

Q You testified above that PacifiCorp's Bridger 3 & 4 retrofit schedule was well ahead of the Regional Haze rule's regulatory compliance timetable. Was PacifiCorp aware that it was pushing for a construction schedule much faster than that required by federal regulations?

A Yes. According to Company's 2010 Plan, "PacifiCorp began implementing its emission reduction commitments in 2005. **This was well ahead of the emission reduction timelines under the regional haze rules** which require BART to be installed no later than five years following approval of the applicable Regional Haze SIP."[36] PacifiCorp was both aware that its compliance was premature and that the Regional Haze Rule itself specified a five year window **after approval of the SIP by EPA**.

In addition, in PacifiCorp's CPCN proceeding for the retrofits in Wyoming, Sierra Club motioned to stay or continue the proceeding until after EPA had made its designations final.[37]

Q What are the reasons that PacifiCorp states it was required to install the SCRs at Jim Bridger in 2015/2016?

A PacifiCorp generates a list of reasons, none of which are the federally enforceable deadline—which was issued after the Company made its firm commitment to its EPC contractors.

Mr. Teply testified that the Company filed an application requesting CPCN at the Wyoming Commission "in compliance" with the 2010 Wyoming Stipulation with

[36] *Id*. at 4 (emphasis added).
[37] Docket No. 20000-418-EA-12, Sierra Club Motion for a Stay or Continuance Pending Final EPA Action (Wyo. Pub. Serv. Comm'n Dec. 21, 2012) [hereinafter "WY PSC, SC Motion for Stay"].

WYDEQ.[38] As I'll describe, the SCRs are regulated—and enforced—under the federal Clean Air Act. There is no record of how PacifiCorp made the determination with WYDEQ that SCRs at Jim Bridger were reasonable, or should be achieved by 2015-2016.

Mr. Teply also testified that the timeline was required by a "Best Available Retrofit Technology (BART) permit issued by the state of Wyoming"[39] in December 2010.[40] That permit was issued as an outcome of 2010 Wyoming Stipulation. As I understand these permits, they allow for the stated modification in a particular timeframe, but are not the records that establish an enforceable deadline.

Q **Finally, Mr. Teply testified that "the Company was required to comply with the timelines set in Wyoming's SIP."[41] The SIP was, until EPA's finalization, simply a draft plan. Mr. Teply testified that "the Company was required to comply with the timelines set in Wyoming's SIP,"[42] and provided a letter from the Wyoming DEQ[43] which he claimed verified the enforceability of the Wyoming claim. Was he correct?**

A No. Mr. Teply's fundamental assertion that the Wyoming DEQ was able to enforce the specific deadlines in its SIP prior to EPA's affirmation of the SIP was, in my lay understanding, incorrect. As I understand the requirements under the

[38] PAC/800 at Teply/26:22-23, 28:9-13.
[39] PAC/800 at Teply/26:22.
[40] PAC/800 at Teply/32, Figure 1—Bridger SCRs Timeline.
[41] PAC/800 at Teply/36:15.
[42] PAC/800 at Teply/36:15.
[43] PAC/830.

rule, Wyoming DEQ had neither state nor federal authority to require compliance with its draft SIP under the federal Regional Haze Rule.

PacifiCorp's letter to Wyoming DEQ (dated March 5, 2013)[44] was sent the day after the Company submitted rebuttal in the Wyoming CPCN (March 4, 2013),[45] and was generated for the purposes of rebutting Sierra Club's assertion that the Company did not have an enforceable deadline. The proper course of action by PacifiCorp would have been to inform Wyoming that it understood its deadline to be contingent on EPA's review and finalization, and that its deadlines would be no earlier than five years after EPA's final approval.

Q What options were open to the Company other than rushing SCR construction ahead of the federally mandated deadlines?

A First, the Company should not have entered into a decade-long compliance schedule with WYDEQ in the 2010 Wyoming Stipulation. Secondly, Regional Haze falls under the federal Clean Air Act, and as the years wore on, and expensive retrofits became less economically viable, the Company should have used the opportunity to adjust its plans through the appropriate channels with EPA. Again, EPA's final Regional Haze FIP was not issued until January 30, 2014. [46] Tellingly, PacifiCorp sued EPA for its SCR requirements under the Wyoming FIP for its other units in Wyoming, but not for Bridger. The Company

[44] PAC/829.
[45] WY PSC, SC Motion for Stay.
[46] Even after it issued the FNTP, the Company still could have terminated the project with minimal costs. I discuss the termination provisions of the EPC contract in Section 3 f (starting page 58).

successfully obtained a stay of the FIP with respect to those other units, [47] but it did not challenge or seek a stay of the EPA's decision to require the Jim Bridger SCRs. As of today, construction deadlines for those other units are still pending.

Q Did the Company have the opportunity to ask EPA to make its deadlines for Jim Bridger 3 & 4 later than 2015 / 2016?

A Yes. In fact, the Company submitted comment to EPA while the agency was analyzing these very deadlines, in August of 2013. But rather than contest Wyoming's Bridger deadlines as inconsistent with Clean Air Act requirements, the Company instead cited the fact that "engineering and permitting is underway for the installation of SCR" at Jim Bridger,[48] and even referenced the recent CPCN process that it had gone through before the Wyoming Public Service Commission ("WPSC") seeking approval to install these retrofits.[49]

It cannot be understated just how backwards, PacifiCorp's process was here. In comments to EPA, the regulatory agency that would ultimately determine what its compliance obligations would be, PacifiCorp instead elaborated on its intent—and actions—to reach a presumptive form of compliance. Any form of urgency to meet a 2015/2016 deadline was of PacifiCorp's own manufacture, and not a

[47] *See PacifiCorp v.EPA*, No. 14-9534 (10th Cir.)(filed Mar. 31, 2014) (PacifiCorp's motion to stay implementation of the FIP granted September 9, 2014 and implementation of the FIP remains stayed as of this writing).
[48] PacifiCorp Comments on Wyoming's Regional Haze Plan, ID EPA-R08-OAR-2012-0026-0149 at 7 (Aug. 26, 2013) (excerpts attached as Exhibit Sierra Club/107).
[49] *Id.* at 35.

product of the federally enforceable requirements of the federal Regional Haze Rule.[50]

Q What are your conclusions with respect to the Company's timeline to install the SCRs at Jim Bridger 3 & 4?

A I conclude that the Company manufactured a compliance deadline that it understood was well ahead of EPA's requirements, and continued to assert that compliance deadline without respect to alternatives or flexibility afforded under the Clean Air Act, and at cost to its ratepayers.

Rather than a 2015/2016 deadline, PacifiCorp had an enforceable 2019 deadline. The additional four to five years of compliance would have afforded PacifiCorp the opportunity to assess additional alternatives, and continue to assess the need to retrofit Jim Bridger 3 & 4, as opposed to either retiring or repowering the units. And as I'll show in Section 3.e (page 44) and Section 3.f (page 58) that additional timeline would have revealed unequivocally that the Company's election to move forward on the retrofits was not in the interests of ratepayers.

The Company's failure to ask EPA for a federally enforceable deadline commensurate with the five-year requirements under the Regional Haze Rule was imprudent.

[50] 40 C.F.R. 51.308(e)(iv).

c. THE COMPANY'S ASSESSED ALTERNATIVES TO CONSTRUCTING SCRS AT JIM BRIDGER WAS FUNDAMENTALLY FAULTY

Q You testified that the Company had alternative compliance options available to it other than the immediate shut down or repowering of the coal-fired unit in order to meet regional haze obligations. What kinds of alternatives were available to states and generators under the Regional Haze Rule?

A EPA worked with states to propose alternative compliance pathways that achieved the same or better cumulative emissions reductions, what is known as "better than BART." For example, in the recent approval of an alternative compliance pathway for PacifiCorp's Naughton 3 coal-fired station, EPA was clear that its guidance on alternative compliance extended back to 2006, stating:

> In 2006, the EPA finalized regulations that govern alternatives to source-specific BART determinations such as that contemplated in the Wyoming SIP revision for Naughton Unit 3. These regulations "make clear that the emissions reductions that could be achieved through implementation of the BART provisions at § 51.308(e)(1) [for source-by-source BART] serve as the benchmark against which States can compare an alternative program." In turn, the emissions reductions that could be achieved through source-by-source BART are calculated in accordance with the Guidelines for BART Determinations Under the Regional Haze Rule.[51]

Q Is the Company today aware of the alternative compliance options available to it under the Regional Haze Rule?

A Yes, very much so. In fact, much of the 2017 Integrated Resource Plan ("IRP") focused on alternative regional haze compliance options, including unit retirements and conversions to gas; pathways that the Company believed would

[51] 84 Fed. Reg. 55, 10433 (Mar. 21, 2019) (internal citations omitted).

provide potentially lower cost options for compliance than installation of pollution controls.[52]

Q Should the Company have been aware in 2013 that there were alternative compliance options available to it rather than the five year compliance window under the Regional Haze Rule?

A Yes. On July 5, 2011, EPA approved Oregon's Regional Haze SIP, which amongst other items, proposed to shut Portland General Electric's ("PGE") Boardman coal-fired power plant by December 2020, well after the five-year compliance deadline under the Regional Haze Rule.[53] In proposing to accept the alternative approach, EPA cited a specific process conducted by PGE and the Oregon Department of Environmental Quality ("ODEQ"):

> In a letter from PGE to ODEQ dated October 22, 2010, PGE requested that ODEQ reopen the Regional Haze BART rulemaking to consider an alternative BART approach for PGE Boardman. This alternative approach would allow PGE Boardman to commit to cease burning coal by December 31, 2020, and in the interim operate with less expensive control technology.[54]

EPA approved this process and finding, an outcome that would have—or should have—been clear to PacifiCorp. And in fact, organizations such as the Citizens' Utility Board ("CUB") of Oregon strove to make it quite clear to PacifiCorp that this type of alternative compliance should be reviewed by the Company. In both

[52] PacifiCorp, 2017 Integrated Resource Plan, at 21 (April 4, 2017), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html ("Compliance associated with Regional Haze requirements continued to be a key area of focus for the 2017 IRP. PacifiCorp developed resource portfolios among seven potential Regional Haze scenarios (including a reference case), assessing how different inter-temporal and fleet-tradeoff compliance outcomes might influence new resource needs and system costs.").
[53] 76 Fed. Reg. 38997.
[54] 76 Fed. Reg. 12651, 12660 (Mar. 8, 2011).

opening comments, and then reiterated in final comments on PacifiCorp's 2011 IRP, CUB explicitly raised this alternative compliance opportunity, stating:

> To the degree that the clean air costs are associated with Regional Haze (BART) SIPs, the range of options that the Company has considered must also be disclosed, since BART contains a fair amount of flexibility tied to the lifetime of the plant. This flexibility allows for a utility to shorten the life of a plant rather than prolong it by adding additional clean air investments, as the total amount of pollution emitted from a plant is greatly reduced by early closure. As such, if a plant is closed early, the shorter life will mean that less pollution control investment is cost-effective and the utility can move towards finding a more efficient replacement resource.[55]

Inexplicably, PacifiCorp ignored CUB's recommendation. Instead, PacifiCorp affirmatively chose not to assess any alternative compliance options for Jim Bridger 3 & 4. It is entirely feasible that a commitment to retire Jim Bridger at a later date, like 2020 or 2022, would have resulted in lower costs in a forward-looking assessment.

Q Has the Commission previously recognized that the Regional Haze Rule provides utilities with flexibility in its timing?

A Yes. In December 2012, this Commission ruled on PacifiCorp's implementation of retrofits at the (still operating) Naughton 1 & 2 coal-fired power plants, finding that the Company's decision and process to build emission controls was analytically and structurally flawed.[56] Specifically, the Commission noted that the inherent flexibility in the Regional Haze Rule as afforded to PGE should have

[55] Opening Comments of the Citizens' Utility Board of Oregon, *In the Matter of PacifiCorp dba Pacific Power 2011 Integrated Resource Plan,* Docket No. LC 52, at 7-9 (Aug. 25, 2011).
[56] Order No. 12-493, *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision,* Docket No. UE 246, at 29 (Dec. 20, 2012) [hereinafter "Order No. 12-493"].

been employed by PacifiCorp in contemplating those retrofits, to the benefit of ratepayers:

> In addition, if Pacific Power had properly explored the potential flexibility in the timing of its options under the RHR, as we believe it had the opportunity to do, the utility and ratepayers would have benefited from additional information that could have been incorporated into cost-effectiveness analyses. That additional information, at a minimum, could have supported later potential shut down dates for use in the PVRR(d) analysis as suggested by CUB and Sierra Club. Indeed, had Pacific Power planned to delay investments at some of its plants, then the utility would have been clearly aware of the "phase-out" analysis conducted by PGE for its Boardman plant and prompted to evaluate the economics of a similar phase-out. As noted by CUB, that analysis permitted PGE to consider a phase-out of its Boardman plant geared toward shutting the plant in 2020, rather than investing in more costly upgrades necessary to allow the plant to operate past that date.[57]

Q What are your conclusions with respect to the alternatives that were available to the Company under the Regional Haze Rule?

A I conclude that the Company failed to assess any alternatives towards lower cost compliance as authorized under the Regional Haze Rule, as conducted by PGE for the Boardman plant, and as recommended by CUB in 2011. These alternatives would have allowed the Company to seek a later firm retirement date for Jim Bridger 3 & 4 rather than install the SCRs. This pause would have ultimately resulted in substantial savings for customers, as I show in Section 3.f (page 58).

The Company's failure to assess alternative options under the Regional Haze Rule was imprudent.

[57] *Id*. at 30.

d. COSTS AND OPERATIONS AT THE BRIDGER MINE CHANGED MATERIALLY IN THE MONTHS PRIOR TO THE FNTP

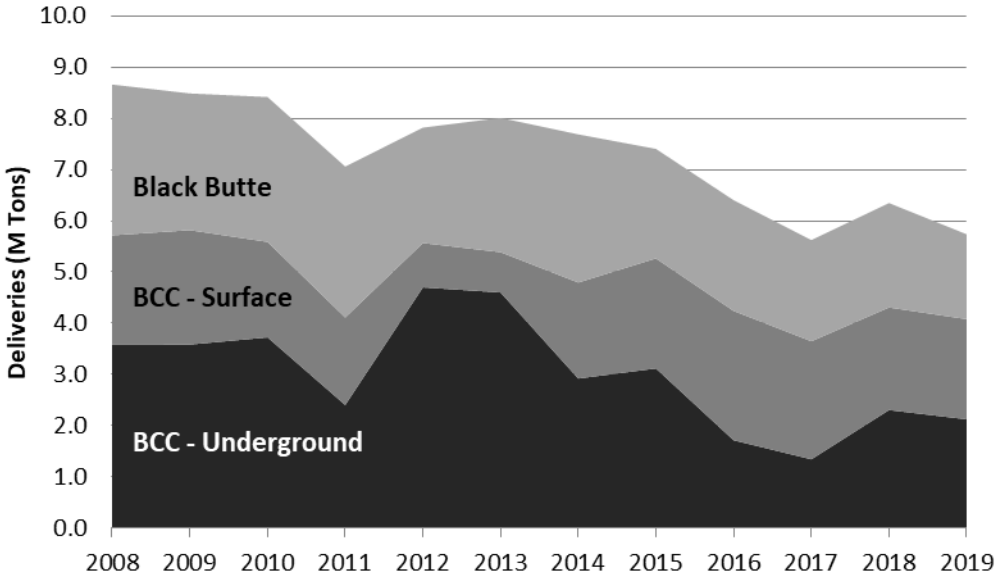
Q How does the Bridger coal plant receive fuel, and how is that relevant to this case?

A The Jim Bridger coal plant receives coal both from the Bridger Coal Company ("BCC"), a mine and company jointly owned by PacifiCorp and Idaho Power Company; and the Black Butte Mine, a commercial coal producer. BCC exclusively serves Jim Bridger plant, while Black Butte mine also serves a small amount of coal to Idaho Power Company's North Valmy station.

Over the last decade, Jim Bridger has received about 2/3rds of its coal supply from BCC, with the remainder coming from Black Butte. My testimony focuses on the Bridger Coal Company mine, and material changes that occurred in mining operations between the time that Mr. Link ran his September 2013 "breakeven" assessment and the signing of the FNTP.

The BCC mine is divided into a surface and underground operation. Over the last decade, the underground mine has contributed around 60 percent of the coal from BCC to Bridger (see Figure 4, below).

Figure 4. Deliveries of coal to Jim Bridger plant (M tons).[58]



The BCC underground mine was opened in 2004, and was meant to extend the longevity of the Bridger mine at a lower cost than the surface.

When doing long-term planning, PacifiCorp constructs what it terms "long-term fueling forecasts," ("fuel forecast") and for the Jim Bridger plant, those forecasts seek to account for the costs of procuring coal from the surface mine, the underground mine, and from Black Butte over a period of decades. For the Bridger SCR assessment, the Company used a fuel forecast from January 2013 (the "January 2013 Fuel Plan").[59]

However in the period between January 2013 and October 2013—i.e. preceding the FNTP date of December 1, 2013—the Company's plan for acquiring fuel at

[58] EIA Form 923, *available at* https://www.eia.gov/electricity/data/eia923/.
[59] *See* Exhibit No. DR-1CT, Confidential Rebuttal Testimony of Dana Ralston, *Washington Utilities and Transportation Commission, Complainant, v. Pacific Power & Light Company, Respondent*, Docket No. UE-155253, at 2:14-16 (Wash. Util. Transp. & Comm'n Apr. 2016) [hereinafter "UTC Ralston Rebuttal Testimony"] (provided as an attachment to PacifiCorp Response to Sierra Club Data Request 1.8(c) (attached as Exhibit Sierra Club/108).

Jim Bridger was thrown into disarray, ultimately causing the Company to come up with a completely different fueling plan for the plant and a very different outlook for the Bridger Mine. The Company admits that as an outcome of this new fueling plan, the costs of maintaining Jim Bridger as a four-unit coal-fired plant increased by [redacted].[60] This increased cost materially devalued the SCR retrofit project, and was not accounted for by the Company at all in its re-assessment of the SCR project prior to executing the FNTP.

Below I explain the basis of the Company's adjustment.

Q How did the Company assess the cost of coal for the Jim Bridger SCR assessment?

A First, it's notable that the fuel costs for Jim Bridger are actually reflected in two different places in the Company's modeling. Because PacifiCorp partially owned the mine, the Company actually incorporated capital costs[61] through a completely different avenue than what it referred to as the "cash costs," which are reflected in the per MMBtu cost of coal.[62] For clarity, I refer to the all-in cost of coal (i.e. including capital) as the "full cost" of coal, while I use the Company's term for the variable cost, the "cash cost."

In assessing both the cash cost as well as the full cost of coal at Bridger for the SCR analysis, the Company developed two completely different fuel forecasts. The first forecast assessed how coal would be procured if all four Jim Bridger units were to run until 2037 (the "four-unit scenario"). The second forecast

[60] *See id* at 8:15.
[61] *See* PAC/707;
[62] *See* PAC/705;

assessed the cost of coal if only two units ran through 2037 (the "two-unit scenario").[63]

Mr. Link briefly described that under a two-unit scenario, the Company had a different set of assumptions for the Bridger coal mine, and requisite costs.[64] He also showed some of the differences between the resulting costs in his accompanying exhibits.[65]

What Mr. Link failed to describe was that under a two-unit scenario, the Company assumed that it would close the surface mine in 2017,[66] relying instead on the underground mine for the remainder of the plant's life, through 2037. The Company assumed that the expedient closure of the surface mine (in the two-unit scenario) would result in the acceleration of the mine reclamation costs.[67] Critically, that acceleration of mine reclamation costs (shown by Mr. Link in Exhibit PAC/706) [redacted] between 2013 and 2018, the period when all four Bridger units are still operating.[68]

In contrast, the four-unit scenario assumed that both the surface and underground mine would persist through 2037.[69]

[63] In its initial CPCN the Company also developed a three-unit scenario assessment that it dismissed as a higher cost alternative.
[64] PAC/700 at Link/91:20-93:3.
[65] *See* PAC/705; PAC/706; PAC/707.
[66] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.8(b).
[67] *See* Exhibit No. CAC-1CT, Redacted Supplemental Rebuttal Testimony of Cindy Crane, *Washington Utilities and Transportation Commission, Complainant, v. Pacific Power & Light Company, Respondent*, Docket No. UE-152253, at 11:18- 12:1 (Wash. Util. & Transp. Comm'n May 2016) [hereinafter "UTC Crane Supplemental Rebuttal"] (attached as Exhibit Sierra Club/109).
[68] Author's calculation from Exhibit PAC/705.
[69] *See* Sierra Club/102, PacifiCorp Response to Sierra Club 1.8(b).

Paradoxically, in the Company's view, it is more expensive to operate the Bridger Coal Company (in absolute terms) when it is producing less coal. These incremental costs were not imposed on the four-unit scenario.

Q What was the total incremental cost that was imposed in the two-unit scenario for assumed accelerated reclamation at the Bridger mine?

A The accelerated reclamation cost was actually imposed as a contribution to a "sinking fund,"[70] or a pool of cash the Company allocates for the use of eventual mine closure. The Company collects an amount every year, determined as the amount necessary, after growth through interest, to fund closure activities at the end of the mine's life. In the four-unit scenario, the Company is able to simply collect $[redacted] per year,[71] while in the two-unit scenario the Company requires contributions of [redacted] per year through 2018 to fund the closure of the surface mine.[72]

Overall, the acceleration of remediation in the two-unit scenario drove up the present value of closure by [redacted] (present value, 2014$) relative to the four-unit scenario.[73]

Effectively, the Company *had* assumed through 2013 that it would continue collecting sufficient revenue through 2037[74] sufficient to fund the massive closure in 2037. Specifically, the Company assumed that compounding interest—and [redacted]—would generate

[70] *See* Sierra Club/109, UTC Crane Supplemental Rebuttal at 6:3-5.
[71] *See* Exhibit PAC/706.
[72] *Id.*
[73] Author's calculation from Exhibit PAC/706
[74] *See* PAC/700 at Link/92:15-18

enough to fund [redacted][redacted][5] of reclamation activities, the bulk of which would [redacted]. This assumption that the Company could effectively self-bond its own closure was interrupted by the two-unit scenario, where the Company's requirement for cash was suddenly accelerated. And while the overall closure cost was much lower – at only [redacted],[76] the impact on the cost of coal increased dramatically.

Q You stated that between January 2013 and October 2013, prior to the completion of the FNTP, circumstances changed dramatically at the Bridger coal mine. How so?

A In March/April of 2013, Bridger Coal Company conducted drilling that resulted in a finding that a panel in the underground mine had excessive ash content,[77] a finding that led to a substantial change in mining operations and ultimately contributed to a rate increase request before the Utah Public Service Commission. That January 2014 Utah rate case presented new costs associated with the Bridger mine. [78] The mine plan supporting those costs was developed in October 2013, two months before the FNTP. [79]

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[75] PacifiCorp 2/3 share. Sum nominal 2013-[redacted]. Author's calculation from Confidential Attachment "BCC Production-Operating Cost Schedules.xlsx" to PacifiCorp Response to Sierra Club Data Request 1.7/Two DL Rev [hereinafter "1.7 Attach_Two DL Rev,_CONF BCC Production-Operating Cost Schedules"].

[76] Author's calculation from Confidential Attachment "BCC Production-Operating Cost Schedules CONF.xslx" to PacifiCorp response to Sierra Club Data Request 1.7/Two Unit Rev2. [hereinafter "1.7 Attach_Two Unit Rev 2_ CONF BCC Production-Operating Cost Schedules"].

[77] *See* Docket No. 13-035-184, PacifiCorp Response to Sierra Club Data Request 4.9(b) (Utah Pub. Serv. Comm'n Apr. 15, 2014) (attached as Exhibit Sierra Club/110).

[78] *See In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184 (Utah Pub. Serv. Comm'n filed Jan. 3, 2014).

[79] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.8(a).

The October 2013 four-unit mine plan ("October 2013 mine plan") shows that the Company had significantly changed its expectations for the Bridger mine since January of 2013. While the January 2013 fuel plan (for four-unit operation) assumed that both the surface and underground mines would be utilized through 2037, [80] the October 2013 mine plan indicated that the Bridger underground mine would cease operations in 2022,[81] and only utilize surface operations through 2037.[82]

Q Why was the change in closure dates for the underground mine in the October 2013 mine plan significant?

A The January 2013 fuel plan had assumed that the surface mine would close in 2017 in a two-unit scenario, requiring an immediate—and costly—remediation. By October 2013, the Company clearly no longer believed that the underground mine had the capacity to provide cost-effective coal through the end of the analysis period. Therefore, it is highly unlikely that the Company would have developed or continued to use a two-unit mine plan that relied on the underground mine, and the acceleration of surface remediation would not have been featured in that two-unit scenario.

[80] *See id.* at 1.8(b).
[81] *See id.*
[82] *See id.*

Q Was the October 2013 mine plan significant?

A Yes, the October 2013 mine plan was the basis for a new business plan at the mine.[83] In a Washington UTC docket on this same issue, the Company verified that "[t]here is no doubt that the October 2013 mine plan reflects changes in the relationship between the surface and underground mining operations at BCC."[84]

The change in disposition of the underground mine in October 2013 was a substantial shift with respect to the Bridger Coal mine. In late March 2013—before the coal ash problems were discovered at the underground mine—Cindy Crane, then CEO of Interwest Mining Company, the PacifiCorp subsidiary which partially owns and operates the Bridger Coal Company, verified that if two units were to shut down the Company would assuredly rely on the underground mine in perpetuity.[85]

By October 2013, the Company was projecting that it would shutter the underground mine by 2022,[86] and that assumption persists. In fact, the Company's recent 2019 IRP verified that in its preferred scenario the underground mine

[83] Docket No. 13-035-184, Redacted Rebuttal Testimony of Cindy A. Crane on Behalf of PacifiCorp dba Rocky Mountain Power , at 11: 193-197 (Utah Pub. Serv. Comm'n June 4, 2014) ("In this test period, based on drilling in March/April 2013, Bridger Coal personnel spent several months re-engineering the mine plan to bypass the 12th right longwall panel. This re-engineered plan is the basis of the 2014 Bridger Coal Business Plan produced in October 2013.").
[84] Sierra Club/108, UTC Ralston Rebuttal Testimony at 8: 5-6.
[85] *See* Docket No. 20000-418-EA-12, Hearing Transcript of Ms. Cindy Crane, at 130:6-16 (Wyo. Pub. Serv. Comm'n Mar. 26, 2013) [hereinafter "WY Crane Hearing Transcript"] (attached as Exhibit Sierra Club/111).
[86] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.8(b).

would close in 2022,[87] and a recent article quoted the Company as projecting a December 2021 closure.[88]

Q What was the impact of the new mining plan on the Bridger SCR assessment?

A The surface mine is a high cost operation.[89] In the Company's January 2013 fuel plan, the Company assessed that the total cost of the surface mine is [redacted], as shown in Confidential Figure 5, below. On a levelized cost basis (2016-2030), the surface mine is [redacted].[90]

Confidential Figure 5. Baseline total cost of coal at Bridger Coal Company surface and underground mines from January 2013, four unit scenario ($/MMBtu)

[redacted]

[87] *See* Docket No. LC 70, Attachment "Attach Sierra Club 3.27" to PacifiCorp Response to Sierra Club Data Request 3.27 (Ore. Pub. Util. Comm'n Nov. 27, 2019) (attached as Exhibit Sierra Club/112).
[88] Andrew Graham, *Life beneath the earth in Wyo's only underground coal mine,* WyoFile (Sept. 3 2019 *available at* https://www.wyofile.com/life-beneath-the-earth-in-wyos-only-underground-coal-mine/ (attached as Exhibit Sierra Club/113.
[89] *See* Sierra Club/111, WY Crane Hearing Transcript at 125: 3-11.
[90] Author's calculation from 1.7 Attach_Two DL Rev_CONF BCC Production-Operating Cost Schedules. Levelized cost of the surface mine is [redacted]. The levelized cost of the underground mine is [redacted].

Therefore, when the Company elected to close the underground mine early, and then shift to the surface mine, it was electing to use a higher cost of coal in the four-unit scenario—a circumstance that would disadvantage the decision to retrofit Jim Bridger with SCR.

Q Did the Company re-assess the value of pursuing the SCR retrofit in light of the need for a new and revised mining plan?

A No. There is no evidence that the Company reviewed, assessed, or even discussed the new mining plan.

Ironically, Ms. Crane had testified just months before that in assessing the value of the SCR the Company strove to use the most up-to-date data, stating:

> In addition, the company has been very diligent in its mine planning to ensure that we have included in the analysis in this proceeding the absolute most current detailed mine planning data available for the decision relating to the SCR installations.[91]

While that may have been true when the Company sought a CPCN in 2012, it was not the case when the Company actually committed customer funds and signed the FNTP.

Q What was the monetary impact of the new October 2013 mining plan on the Bridger SCR decision?

A An independent assessment of the monetary impact is almost impossible from a third-party perspective. The Company did not translate the new mine plan into a comprehensive "fueling plan" until November 2014, in preparation for the 2015

[91] Sierra Club/111, WY Crane Hearing Transcript at 125:19-23.

IRP,[92] and the Company never created a two-unit scenario with the new October 2013 mining plan.[93]

While both UTC Staff[94] and I[95] have previously attempted to create an estimated four- and two-unit coal cost scenarios in the past, the Company's source workbooks for Bridger fuel costs are a warren of broken links,[96] circular references,[97] inscrutable structures,[98] and the Company's characterization of costs as either "cash costs" or that flow to capital are both ill-defined and changing.[99]

In its Washington presentation of this case, the Company rebutted my assessment of the impact of the new mining plan, but affirmed that the new mine plan represented "changes in the relationship between the surface and underground mining operations at BCC."[100] Company witness Dana Ralston, Vice President of Thermal Generation at PacifiCorp, provided a revision to my assessment, and estimated that the new October 2013 mine plan had resulted in an increased cost

[92] *See* Sierra Club/108, UTC Ralston Rebuttal Testimony at 10:2-3.
[93] *Id*. at 10:19-20.
[94] UE-152253, Supplemental Testimony of Jeremy B. Twitchell on Behalf of UTC Staff (Exhibit JBT-19HCT), at 9-15 (Wash. Util. & Transp. Comm'n May 6, 2016) (attached as Exhibit Sierra Club/114).
[95] UE-152253, Direct Testimony Jeremy Fisher on Behalf of Sierra Club, at 20:22-21:19 (Wash. Util. & Transp. Comm'n Mar. 17, 2016).
[96] Opening the Company's fuel plan workbook entitled "BRIDGER Rev 1-18-13 CONF. xlsx" (provided as a confidential attachment to PacifiCorp Response to Sierra Club Data Request 1.7) produces an unreadable content flag, and flags a number of broken links.
[97] Opening the Company's Bridger Coal Company core workbook "BCC Production-Operating Cost Schedules. xlsx" produces a circular reference warning. *See* 1.7 Attach_Two DL Rev_CONF BCC Production-Operating Cost Schedules.
[98] For example, in the Bridger mine workbook, [redacted]. *See* 1.7 Attach_Two DL Rev_CONF BCC Production-Operating Cost Schedules.
[99] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.7(f) (listing line items included in "cash costs" and noting that "reclamation contributions were included in cash costs in these scenarios, however, they are not included in the 2019 Integrated Resource Plan cash cost.").
[100] Sierra Club/108, UTC Ralston Rebuttal Testimony at 8:5-6.

of [redacted] to the Bridger SCR retrofit decision[101]—thereby degrading the value of the SCR by [redacted].

Notably, Mr. Ralston's assessment was conducted *post hoc*. He calculated his adjustment to the value of the SCR projects using work papers that I had constructed to assess the potential change in value. There was no affirmative Company assessment or adjustment conducted between October 2013 and the signing of the FNTP in December 2013.

Layered on top of Mr. Link's re-assessment using September 2013 gas prices, the value of the SCR retrofit would have fallen by another [redacted] to [redacted].

Q Is it your opinion that Mr. Ralston's estimate of the cost increase associated with the shift to surface mining may have been a lowball estimate?

Yes. As I noted earlier, the Company's two-unit scenario assumed that the surface mine would need to be remediated immediately, requiring an increase in reclamation payments of [redacted] (present value, 2014$) relative to the four-unit scenario.[102] Once the surface mine was the exclusive source of coal, there was relatively little difference between the timing of the closure obligation for the two-unit scenario and the four-unit scenario. In addition, the two-unit scenario would presumably have disturbed less landscape, requiring less reclamation. Mr. Ralston did not factor in the lack of accelerated reclamation nor the reduction in total reclamation associated with a surface-based two-unit scenario. Accounting for these changes would have increased the discrepancy between the two-unit and

[101] *See id.* at 8:14-15.
[102] Author's calculation from Exhibit PAC/706.

four-unit scenarios by potentially [redacted],[103] to the detriment of the Bridger SCR projects.

Q What are your conclusions with respect to the new mine plan at Bridger mine in October 2013?

A I conclude that the Company failed to properly or timely assess the impact that its new October 2013 mining plan would have on the value of the Bridger SCR decision. That new plan resulted in a degradation of value by anywhere from [redacted], but the Company ignored this information in the run-up to signing the FNTP.

The Company acted imprudently in failing to account for the new mine plan, available prior to the December 1, 2013 FNTP.

e. GAS PRICES FELL RAPIDLY IN THE MONTHS LEADING UP TO THE FNTP

Q You earlier testified that in the months leading up to the FNTP, industry analysts and PacifiCorp were projecting substantially lower forward-looking gas prices which PacifiCorp ignored when assessing the value of Jim Bridger when the Company executed the FNTP. Please explain.

A PacifiCorp's records at the time show that when it signed the FNTP, it understood that gas prices would likely become—and remain—depressed on a going-forward basis. This was new information that was not represented in the Company's analyses preceding the FNTP.

[103] Addition of the Ralston's [redacted] mine plan adjustment and an incremental [redacted] adjustment to account for the lesser near-term reclamation costs.

Mr. Link described that the Company elected to move forward on the Bridger SCR retrofits on the basis of his "breakeven" assessment, in which he assessed that the levelized cost of local gas prices from 2016 to 2030 would have to drop below $4.86/MMBtu[104] in order for the Company to re-assess its retrofit decision. In constructing that assessment, Mr. Link described that he used a September 2013 gas price forecast, which still projected gas prices at $5.35/MMbtu,[105] above his breakeven. Mr. Link testified that at this price point, the SCRs benefited customers by approximately $130 million.[106]

It is notable that from a statistical standpoint, the $5.35/MMBtu gas price was not a robust indicator that the retrofit was cost effective, even relying on Mr. Link's shortcut breakeven assessment. In fact, at a 90 percent confidence interval, the SCRs either continued to be a benefit to consumers, or were already a liability. And since gas prices are inherently uncertain,[107] there was a distinct potential—particularly if gas prices trended downward—that the SCRs would pose a liability to consumers.

The Company did not conduct any further analysis with respect to gas prices and did not conduct further modeling on the value of pursuing the retrofit.

The "September 2013" gas price forecast that Mr. Link relied on is the Company's own internal "Official Forward Price Curve" ("OFPC"), a quarterly 30-year projection compiled by Mr. Link and for which Mr. Link bears

[104] PAC/700 at Link/101:13-17; Link/106:4-21.
[105] *Id.* at Link/107:6-9.
[106] *Id.* at Link/107:6-13.
[107] *Id.* at Link/107:15.

responsibility.[108] As far as I can discern, Mr. Link develops the OFPC gas price forecast by consulting forecasts from three private vendors,[109] the Energy Information administration, and forwards on commodity exchanges.

When Mr. Link produced the Company's December 2013 OFPC on December 31, 2013, the levelized price of gas at Opal had dropped to $5.00/MMBtu.[110] According to Mr. Link's "breakeven" assessment, that would have left the value of the Bridger SCRs at just [redacted]—or a drop of [redacted] from Mr. Link's "base case" of $186 million.[111]

Below, I show why assessing the cost of gas using a projection that theoretically wasn't available until December 31, 2013 is consistent with the information available to the Company at December 1, 2013.

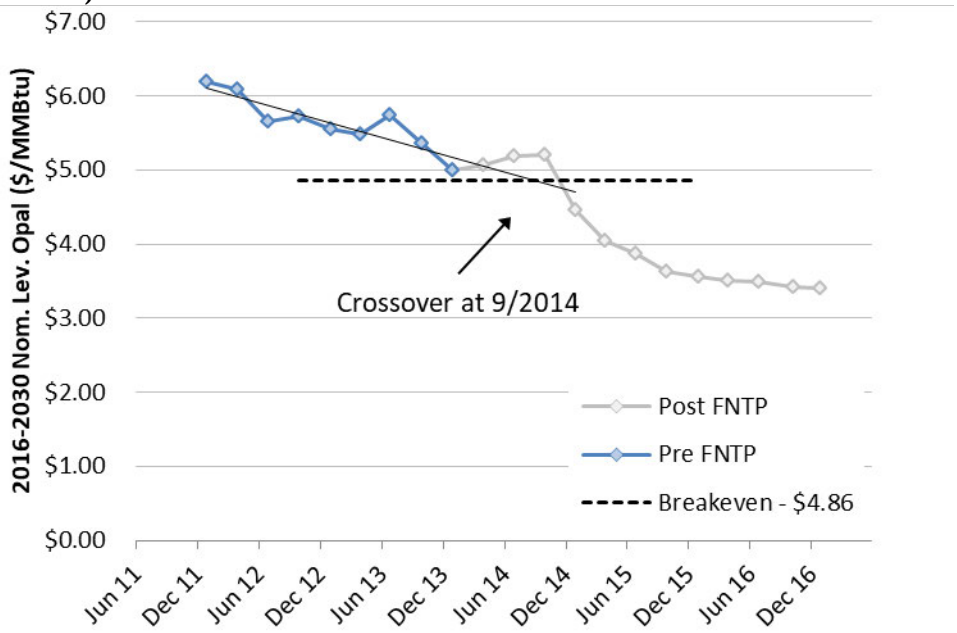
Q Mr. Link testified that "PacifiCorp also considered that . . . natural-gas prices cannot trend downward indefinitely."[112] To what trend is Mr. Link referring?

A Mr. Link was referring to the fact that from the time of the Company's August of 2012 CPCN application before the Wyoming PSC, which relied on a gas price forecast from December 2011,[113] the Company's projection of future gas prices had fallen steadily, dropping by $1.18/MMBtu by December 2013. In fact, just projecting forward from the Company's own projections of prices at the Opal hub

[108] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.6(a)-(b).
[109] *See* Sierra Club/102. PacifiCorp Response to Sierra Club Data Request 1.5(b) (Vendors are PIRA, CERA, and Woods Mackenzie.).
[110] Authors calculation from data provided in Attach Sierra Club 1.6.xlsx .
[111] PAC/700 at Link/86:15-17.
[112] *Id.*at 107:14-16.
[113] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.1(h).

would have showed that the project would cross Mr. Link's notional "breakeven" of $4.86/MMbtu in September 2014 (see Figure 6).

Figure 6. PacifiCorp projections of Opal gas prices Dec 2011- Dec 2013 (blue) and 2014-2016)[114]



As I discuss below, while gas prices did not trend down "indefinitely," they absolutely continued to fall through the execution of the SCR project. And as I show in Section 2.g (page 62), below, gas prices in fact fell faster than the Company's termination provisions from the contract, meaning that it could have exited the contract mid-project and still provided customer benefits.

[114] Author's calculation from, Attach Sierra Club 1.6.xlsx, using Link formulation for real levelized cost.

Q The Company signed the FNTP on December 1st, 2013, but you testify that the Company's lower projection wasn't produced until December 31st. Did the Company have sufficient information by December 1st to know that prices were falling?

A Yes. It is notable that the OFPC is produced internally from information that the Company had on hand. On December 1, 2013, PacifiCorp had the following new information:

- Two new forecasts from third-party vendors, CERA (accessed November 21, 2013) and Wood-Mackenzie (accessed October 22, 2013).[115] Relative to prior forecasts (in [redacted] and [redacted], respectively[116]), both vendors were projecting [redacted] across the 2016-2030 analysis window ([redacted] respectively).
- Commodity trading forwards for natural gas. A retrieval for Henry Hub prices, a heavily traded gas hub, indicates that between the 2nd and 3rd quarters of 2013, gas price forwards for January 2018 fell by 6-10%, from between $4.6-$5.1/MMBtu in July-September to $4.3-4.5/MMBtu in September to December. This sustained projected price fall, repeated for every year 2014-2020, would have been apparent to PacifiCorp.

[115] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.5(b).
[116] *See* Confidential Attachments1.5-2 to PacifiCorp Response to Sierra Club Data Request 1.5 (attached as Exhibit Sierra Club/115.

Figure 7. NYMEX Futures for 2018 HH, 2012-2016, indicating fall in forecast during 2013. [117]



- The Energy Information Administration's ("EIA") Short Term Energy Outlook ("STEO") does not extend beyond a year, and would have served limited value for this analysis. Nonetheless, the November STEO (Nov 13, 2013)[118] projected prices about three percent lower in 2014 than had been projected in the August STEO (August 6, 2013).[119]

The next Annual Energy Outlook ("AEO") "early release" product was not available until December 16, 2013.

[117] CME Group, January 2018 Henry Hub gas futures with one-week average open, high, low, close (accessed Mar. 15, 2016.).
[118] EIA Short Term Energy Outlook, November 2013, *available at* https://www.eia.gov/outlooks/steo/archives/nov13.pdf.
[119] EIA Short Term Energy Outlook, August 2013, available at https://www.eia.gov/outlooks/steo/archives/aug13.pdf.

The new information available to PacifiCorp between September 2013 and December 1, 2013 all indicated a downward trend in forward gas prices. This trend was ultimately reflected in the Company's December OFPC, and should have been reflected at the start of that month, had the Company sought to consult its standard data sources.

Q How stale was the data PacifiCorp used to inform the September 2013 OFPC?

A PacifiCorp doesn't provide insight into its black box process of developing OFPCs, but it did provide the two prior vendor forecasts presumably used in the September 2013 OFPC. While CERA is dated [redacted], Wood-Mackenzie is dated [redacted]. This means that if these vendor forecasts were a substantial part of the OFPC, elements of the OFPC were [redacted] old by the time PacifiCorp finalized the FNTP.

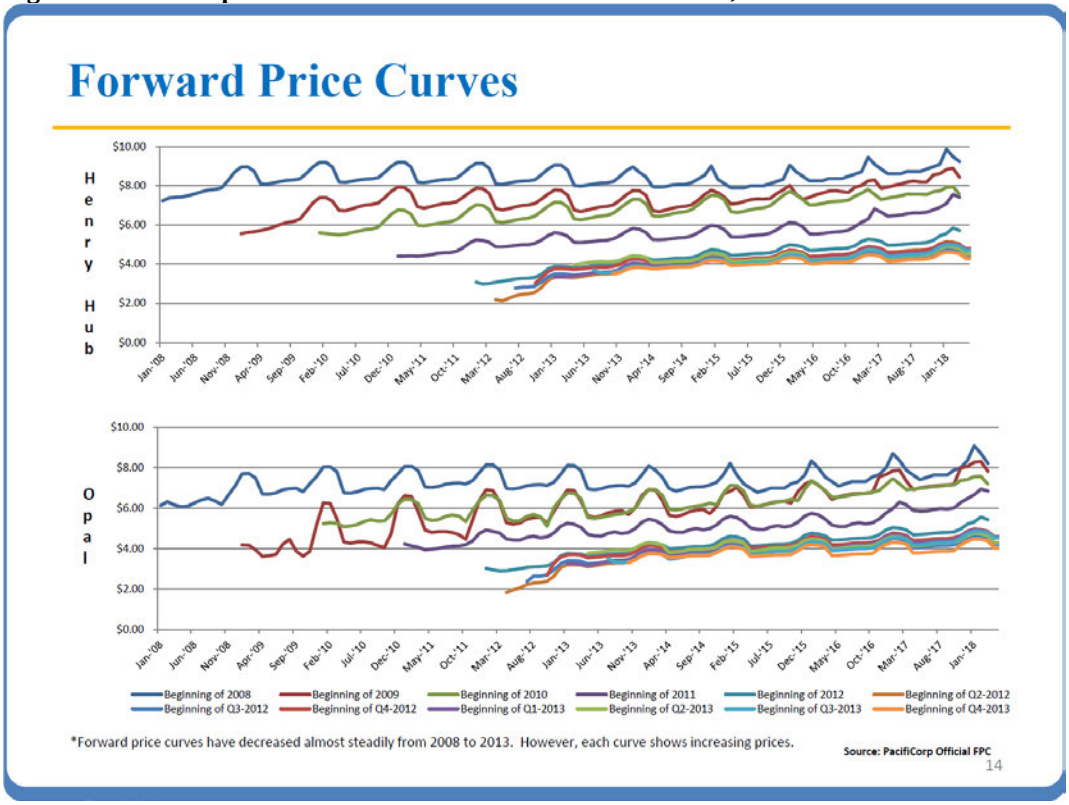
Q Did PacifiCorp recognize that gas prices were dropping rapidly through 2013?

A Yes. In an October 29, 2013 workshop on a natural gas RFP process, PacifiCorp developed a slide with a series of then-recent OFPCs, dropping from 2008 through the September 2013 OFPC.[120] That slide, shown below in Figure 8, indicated that "forward price curves have decreased almost steadily from 2008 to

[120] PacifiCorp,*2012 Natural Gas Request for Proposals Workshop* (Oct. 29, 2013)(also provided in UTC docket UE-152253 as Exhibit No. JIF-8) (attached as Exhibit Sierra Club/116).

2013."[121] The curves show that the Company, in fact, had revised gas price futures downwards in recent OFPCs as well, and was therefore aware of the trend.

Figure 8. PacifiCorp slide on Forward Price Curves. October 29, 2013.



In addition, the Company produced two short-term OFPC, dated October 31, 2013 and November 8, 2013.[122] These forecasts only extended through December 2016, and are thus of limited value, but provide a sense of directionality. In October, 2013 PacifiCorp projected that gas prices would be nearly 3 percent lower through 2016 than the September 2013 OFPC, and in November 2013, PacifiCorp was already projecting that gas prices would be nearly 5 percent lower through 2016 than the September 2013 OFPC.

[121] *Id.* at 14.
[122] *See* Attach Sierra Club 1.6. xlsx at tab "11-08-2013" and tab "10-31-2013".

PacifiCorp clearly understood that forward gas prices were falling after the September 2013 OFPC. Nonetheless, PacifiCorp failed to construct a new assessment of forward gas prices or uncertainty in those prices, failed to conduct new or additional modeling, and failed to convey internally or externally that the economics of the Bridger SCR had degraded.

Q Is the fact that the Company only produces long-run OFPCs on a quarterly basis relevant?

A No. The Company's election to create OFPC on a quarterly basis is useful, but arbitrary. There are no specific pieces of information that are only available to the Company on a quarterly basis—the Company simply elects to finalize its OFPC on that schedule.

The information driving the lower gas prices projected in PacifiCorp's December 2013 OFPC would have been available to PacifiCorp on and before December 1, 2013. A reassessment using the Company's own mechanism and own projection of levelized gas prices (2016-2030) at $5.00/MMBtu would have revealed that—according to a gas price adjustment alone—the benefit would have dropped to [redacted],[123] or a reduction of [redacted] from the Company's assessed $183 million "Base Case" in the instant docket.[124]

[123] Based on Mr. Link's linear relationship between the levelized cost of gas and the SCR benefit, B_{SCR}= [redacted] * P_{NG} + [redacted], where B_{SCR} is the benefit of SCR decision (PVRR(d)) in millions of 2014 dollars, and P_{NG} is the levelized cost of gas at Opal hub from 2016-2030 at a 7.15% discount rate.
[124] PAC/700 Link/86:15-17.

Q Mr. Link testified that "[b]efore issuing the FNTP PacifiCorp was aware that EPC costs for the Jim Bridger SCR emission control systems had been reduced by [redacted] . . ." which resulted in [redacted] in additional benefits to the SCR compliance alternative."[125] How does this factor into your assessment?

A Even taking into account the incremental benefit of [redacted], the final overall value of the projects were not substantial going into the FNTP. Layered on top of the Company's own admitted change in coal prices received from the Bridger mine, which had already reduced the benefit of the SCRs to [redacted],[126] the Bridger SCRs were reduced to basically a wash—from the perspective of a system the size of PacifiCorp's— with a benefit of only [redacted][27] by December 1, 2013. In other words, when the Company signed the FNTP, the SCRs presented no ratepayer benefit.

Q Mr. Link also testified that "there was a reasonable possibility that actual natural-gas prices could be higher than then-current base-case projections."[128] Do you have a response?

A Yes. It is true that gas prices could have trended higher than the Company's then-current base-case projections. And gas prices could also have trended lower than the Company's then-current base-case projections, which is the value proposition

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[125] *Id.* at Link/108:3-6.
[126] Company's September 2013 breakeven assessment value of $130 million less Ralston's [redacted] October 2013 coal price adjustment = [redacted]
[127] Company's breakeven assessment applied to Company's December 2013 OFPC, resulting in [redacted] benefit for the SCR, less Ralston's [redacted] October 2013 coal price adjustment, plus Mr. Link's [redacted] SCR cost reduction = [redacted]
PAC/700 at Link/107:16-18.

behind sensitivities and characterizing risk. But the risk bands that Mr. Link discussed in his testimony,[129] shown graphically in Figure 14, are from September 2012 and were 15 months stale—and moot—by the time the Company signed the FNTP. The Company did not produce risk bands associated with its September 2013 OFPC.

Q Given the marginal outcome for the Bridger SCR project in December 2013, what action should the Company have taken?

A The rapidly declining benefit of the Bridger SCR project should have galvanized the Company to perform a far more rigorous assessment of the benefits or costs of continuing with the SCR projects. It should have paused the execution of the FNTP, if necessary, in order to conduct a final rigorous analysis.

Q What are your conclusions with respect to falling gas price leading up to the FNTP?

A I have several conclusions:

1. The Company failed to assess new market price projections available to it prior to December 1, 2013 that would have revealed lower market price forwards for gas.
2. The Company's use of a shortcut "breakeven" assessment, which relied on modeling data more than 15 months old at the time of the FNTP was unbefitting for a project of this scale and magnitude.

[129] PAC/700 at Link/102:18-105:

3. The Company was aware that the margin for the Bridger SCRs was tightening, and failed to conduct more extensive or intensive modeling to determine if the decision was still in the best interests of ratepayers prior to the signing of the FNTP.

In sum, the Company acted imprudently by failing to produce an adequate assessment prior to signing the FNTP, and the Company acted imprudently in failing to assess up-to-date gas price forwards at the time it made the decision to move forward with SCR construction.

Q Did the Company re-assess the value of the Bridger SCR on the basis of falling gas prices or increasing coal costs?

A No. The Company conducted no modeling on the benefit of the Bridger 3 & 4 SCRs after January 2013,[130] and did not re-assess the value of the Bridger SCR after September 2013 through any mechanism.

[130] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.4(d).

Q The Company now claims that before issuing the FNTP, "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,"[131] and claims that "[Mr]. Teply personally performed the review of these factors, in regular consultation with Mr. Link and members of PacifiCorp's fuels group."[132] What is your opinion of these assertions?

A The Company has not provided **any** evidence that it actually reviewed these projections. Sierra Club requested that the Company provide evidence indicating that the coal and changed gas prices had been considered. The Company objected that it had no obligation to provide contemporaneous documentation of any its decisions.[133] When asked to provide notes or emails discussing these changes, the Company responded that all such records would have been erased.[134]

In fact, in its Washington presentation of this case, Mr. Teply—no longer employed by PacifiCorp, but responsible for the SCR installation—stated that any such reviews would have been informal, testifying:

> [T]he reviews that we would have completed here prior to issuing full notice to proceed would have been literally sitting down at a desk, looking at the screen, looking at the actual data, and making a decision as to whether there was any material change there that would have then triggered a reason to go back and reassess compliance approaches. In this instance there were none […]

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[131] *Id.* at 1.4(b).
[132] *Id.*
[133] *Id.*
[134] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request SC 4.3(a)-(b).("Internal emails are not routinely saved but are automatically deleted in the normal course of business after 90 days unless deliberately saved by a user. PacifiCorp is conducting an internal review of responsive emails. None have been identified to date.").

> There would be no memo documenting these three particular decision points in one place, no.[135]

There is additional evidence showing that the Company **did not** consult up-to-date gas prices or the new fueling plan.

1. In the spring of 2014, Sierra Club was engaged in PacifiCorp's general rate case in Utah, and asked if the changed coal costs from October 2013 had been assessed with respect to the Jim Bridger SCRs. The Company responded that:

> A comparison of [2014] test period [coal] costs to the CPCN approval docket for the Bridger 3 & 4 SCR **has not been completed**. Since the CPCN analysis, Bridger Coal Company mine costs and quality have been updated as part of the annual mine planning process.[136]

2. The Company provided an internal memorandum written December 5, 2013 explaining the Company's decision to ultimately sign the FNTP. The memorandum, [redacted], but made no mention of either gas or fuel price changes, or even Mr. Link's economic analysis supporting the decision to move forward.[137]

3. In its Washington presentation of this same case, the Company rebutted my assertion that the coal price differential between the two- and four-unit scenarios had increased, using a *post* hoc analysis, as I described on page 43, above. The fact that the Company's analysis, performed by Mr. Ralston, was

[135] Order 12, *Washington Utilities and Transportation Commission, Complainant, v. Pacific Power & Light Company, a Division of PacifiCorp, Respondent,* Docket No. UE-152253, at ¶92 (Wash. Util. & Transp. Comm'n Sept. 1, 2016) [hereinafter "Order 12"].
[136] Docket No. 13-035-184, PacifiCorp Response to Sierra Club Data Request 4.10(d) (Utah Pub. Serv. Comm'n) (emphasis added) (attached as Exhibit Sierra Club/117).
[137] PacifiCorp, December 5, 2013 Memorandum (provided as confidential attachment "Attach Sierra Club 1.4-3 CONF.pdf" to PacifiCorp Response to Sierra Club Data Request 1.4, (attached as Sierra Club/118).

conducted as a modification to my already heavily modified work papers, and was not provided as an assessment conducted by the Company at the time clearly indicates that the Company had not assessed the coal price differential at the time.

From the evidence here, I conclude the Company never actually reviewed the changes in gas or coal prices after September 2013, and prior to signing the FNTP on December 1, 2013.

f. THE LIABILITY OF THE JIM BRIDGER SCRS EXCEEDED THE COST OF CONTRACT TERMINATION WELL BEFORE THE PROJECT REACHED COMPLETION

Q Was the drop in gas prices and reduction in value of the Bridger SCRs a temporary downturn restricted to December 2013, or did lower gas prices persist?

A With the exception of a three-quarter excursion in mid-2014, the Company's projected gas prices continued to fall after the execution of the FNTP (see Figure 6, page 47). By December 2014, the Company projected that the forward cost of gas at the Opal hub had fallen to $4.47/MMBtu (2016-2030), or $0.39/MMBtu **below** Mr. Link's breakeven. Had the Company assessed the SCRs as a new project in December 2014, it would have made the determination that the SCRs were a deep liability. On the basis of gas prices alone and using Mr. Link's 2012 gas/benefit relationship,[138] the Company would have assessed a liability of over [redacted] for pursuing the SCRs. Of course the SCRs were already under

[138] *See* PAC/700 at Link/107:9-10.

contract by late 2014—but the value proposition kept plunging as gas prices sank further and further.

Just three months later, in March 2015, Mr. Link's breakeven assessment would have shown a liability of [redacted]. Accounting for the now-solidified Bridger fueling plan (which assumed the near-term closure of the underground mine) and the assessed slightly lower cost of the SCR projects, a contemporaneous assessment would have shown an SCR liability of [redacted]

Q Even if the Company had already spent a large fraction of the Bridger SCR budget, was there a point in the construction process where it still would have been prudent to terminate the project prior to completion?

A Yes. 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 interests of ratepayers. The Company's contract with the SCR construction firm included "termination rights and an associated cancellation schedule,"[139] [redacted][140] [redacted] At any point when the liability of continuing to pursue the project exceeded the cost of terminating the contract, the Company should have scrutinized the value of ceasing the project.

[139] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.3(d).
[140] *See* Highly Confidential Attachment 1.4-3, "Exh B to EPC Contract" to PacifiCorp Response to Sierra Club 1.3(e) (attached as Exhibit Sierra Club/119).

This inflection point occurred between January 2015 and April 2015. By April 2015, the liability of the Bridger SCRs at [redacted] exceeded the contractor's [redacted].[142] From this rough assessment, terminating in April 2015 would have saved ratepayers [redacted]. Highly Confidential Figure 9, below, shows the [redacted] against the value of the Bridger SCR projects.

Highly Confidential Figure 9. SCR contractor associated cancelation schedule (i.e. [redacted] versus the value of the Bridger SCR projects from December 2013 (including adjustment for coal and SCR cost savings) through the completion of the project.[143]

[redacted]

The [redacted] subject to change on the basis of the actual project costs. It is possible that termination could have been invoked earlier in a cost effective manner, as well.

[141] Author's calculation from OFPC provided in Attach Sierra Club 1.6.xlsx, tab "0314"
[142] *Id.*
[143] Author's calculation, and Sierra Club/119, "Exh B to EPC Contract" to PacifiCorp Response to Sierra Club 1.3(e).

To continue with a failed project is to succumb to the sunk cost fallacy. Not only should the project not have commenced, it should never have been completed.

Q Did the Company provide detailed modeling or assessment of the Jim Bridger SCRs after they commenced?

A No. Sierra Club asked the Company if it re-assessed the Bridger SCRs using the System Optimizer model at any time after February 2013, and the Company confirmed that it did not.[144]

The Company did not include any assessments of Jim Bridger 3& 4 in its contemporaneous IRP either. On March 31, 2015 the Company submitted its 2015 IRP. Each and every assessed case included an assumption that Jim Bridger 3 & 4 would be retrofit with SCR and run through 2037.[145]

Q What conclusions do you draw about the Company's assessment of the Bridger SCRs after the FNTP?

A After signing the FNTP, the Company failed to assess whether continuing with the Bridger SCRs was cost effective and in the best interests of customers. My analysis demonstrates that customers would have benefited by [redacted] had the Company elected to terminate the projects—and the units—in early 2015.

[144] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.4(d).
[145] PacifiCorp, *2015 Integrated Resource Plan*, Vol. II, at 148, Figure 7.2 (Mar. 31, 2015), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html ("Common to all scenarios: Carbon 1&2 shut down 2015; Colstrip 3&4 SCR 2023/2022, respectively; Craig 1&2 SCR 2021/2018, respectively; Hayden 1&2 SCR 2015/2016, respectively; Naughton 1&2 shut down 2029; Naughton 3 gas conversion 2018, shutdown 2029; Hunter 1&3 SCR 2021/2024, respectively; and Bridger 3&4 SCR 2015/2016, respectively").

The Company acted imprudently by failing to terminate the SCR projects, once the forward liability of continuing the projects and operating Jim Bridger 3 & 4 on coal fell below the cost of ceasing construction.

g. THE CONTINUED OPERATIONS OF JIM BRIDGER HAVE IMPOSED SUBSTANTIAL AND CONTINUING HARM ON PACIFICORP'S RATEPAYERS

Q Have ratepayers continued to be harmed by Jim Bridger 3 & 4 and the Company's election to install SCR at these units?

A Yes. I estimate that, using Mr. Link's "breakeven" assessment, adjusting for coal and SCR costs, ratepayers would have benefited by [redacted] by December 2015 if the Company had retired Jim Bridger 3 & 4 in 2015/2016, rather than installing SCRs. This value is remarkably close to a damage value derived from the Company's most recent IRP, and then accounting for the costs of the SCRs. In October 2019, the Company submitted its 2019 IRP, which assessed the economics of specific coal units, and for the first time assessed the value of maintaining coal units not facing large new capital expenditures. The IRP showed a ratepayer benefit of $141million (present value 2019$) if the Company sought the retirement of Jim Bridger 3 & 4,[146] with the SCRs already a sunk cost. Adding the total cost of those SCRs,[147] at [redacted] (inflated from 2015$ to 2019$) amounts to [redacted] (2019$) in savings allocated to customers if the Bridger SCRs had been avoided.

[146] PacifiCorp, 2019 Integrated Resource Plan, Volume II, Appendix M, at 274 -275 (Oct. 18, 2019), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html (Comparing case P-35 ("Jim Bridger 3&4 Retirement 2022") at $21,732 million and "parent" case P-11 ("Cholla 4 Retirement 2020") at $21,873 million.).

[147] PAC/800 at Teply/33:22 [redacted] for the Jim Bridger 3 SCR); PAC/800 at Teply/35:17 () [redacted] for Jim Bridger 4 SCR).

Q Does this Commission have an established standard for disallowing imprudent expenditures?

A Yes. In 2012, the Commission ruled that "[b]ecause the purpose of a prudence review is to hold ratepayers harmless from any amount imprudently invested, a disallowance should equal the amount of the unreasonable investment."[148]

Here, the "amount imprudently invested" was the totality of the SCRs at Jim Bridger 3 & 4, and subsequent capital and operating expenses that continue to harm ratepayers relative to the Company's alternative options.

Q Do you have a recommendation as to how the Commission should assess damages associated with the implementation of the Bridger SCRs?

A Yes. The Company has provided sufficient evidence to show that customers will incur harm well above the cost of the SCRs themselves. In December 2015, that total harm was [redacted] (as shown above), while a rough estimate in 2019 is that the total harm is roughly [redacted].

One portion of the estimated harm are the costs already incurred through the Company's election to construct the Bridger SCRs; namely, the cost of the SCRs and the excessive cost of operating Jim Bridger from 2015/2016 to the present day. Another portion of that harm is the costs incurred should the Company continue to operate Jim Bridger 3 & 4 through 2037 with the SCRs in place. The costs that are avoidable through the further operation of Jim Bridger 3 & 4 are

[148] Order No. 12-493 at 31.

still avoidable. Those costs are not yet ratepayer harm, but will be should the Company continue to operate these units above the cost of cheaper alternatives.

The costs the Commission should assess for disallowance are the totality of costs incurred to date (including both SCR and other capital) against the Company's alternative to either have converted the units to gas, or invoking an alternative under the Regional Haze Rule. The harm that will incurred by ratepayers through the continued use of Jim Bridger is still avoidable through the cessation of operations at Jim Bridger 3 & 4.[149]

We do not have a ready mechanism for assessing which costs make up the difference between the Company's chosen course of action and the lower cost option from 2015 through today at realized fuel, gas, and market prices. Therefore, I offer two alternatives:

1. The Commission could require the Company to assess the costs of having converted to gas in 2015/2016 or having delayed retirement or repowering until 2019, and assess damages as the difference between actual and theoretical capital plus operational costs incurred from 2013 to the present day; or

[149] The Commission, however, should consider any harms pressed upon ratepayers by the Company's inability or unwillingness to retire the Jim Bridger 3 & 4 units in a timely fashion if such inability or unwillingness was otherwise avoidable through the conversion or retirement of these units at an earlier date.

2. The Commission could elect to identify the costs of the SCRs, [redacted], or [redacted] on an Oregon-allocated basis,[150] as the imprudent investment, and disallow the costs of the SCRs in full.

In my opinion, based on the 2019 IRP results, the avoidable forward-looking damages associated with continuing to run Jim Bridger 3 & 4 are the same order of magnitude as the SCR costs, and therefore the damages resulting from options 1 and 2 are probably proximate. In addition, because option 1 relies on a hypothetical, option 2 may be the simpler option. Therefore, I recommend that the Commission disallow the full costs of the SCRs.

Q You stated earlier that the Company made a similar presentation of this case before the Washington Utilities and Transport Commission ("WUTC") in 2016. What was the finding of the WUTC?

A The WUTC found that PacifiCorp failed to show that it had taken new information about gas and coal prices into account when making its decision to proceed with the FNTP,[151] specifically citing the substantial change in coal mining plans,[152] falling gas prices,[153] and the Company's lack of a rigorous modeling approach given the important changes afoot.[154] As a result, WUTC elected to disallow the return on investment for both the Bridger 3 and 4 SCRs.[155]

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[150] PAC/800at Teply/33:22 [redacted] for the Jim Bridger 3 SCR on an Oregon-allocated basis); PAC/800 at Teply/35:17 [redacted] for Jim Bridger 4 SCR on an Oregon-allocated basis).
[151] Order 12.
[152] *Id.* ¶ 104.
[153] *Id.* ¶ 105.
[154] *Id.* ¶ 102.
[155] *Id.* ¶ 116.

The evidence shows that a broader disallowance including the cost of the SCRs themselves is warranted to make whole Oregon ratepayers.

4. PACIFICORP'S ELECTION TO ALLOW ENVIRONMENTAL RETROFITS AT HAYDEN WAS INCONSISTENT WITH ITS OWN ASSESSMENTS

Q Please provide background on the environmental retrofits at the Hayden power plant.

A Mr. Teply briefly described two selective catalytic converter ("SCR") projects installed at Hayden units 1 & 2, in Colorado,[156] with a cost to PacifiCorp ratepayers of [redacted], or [redacted] on an Oregon-allocated basis.[157] For a number of reasons, it is notable that PacifiCorp is a minority owner at Hayden, with a 24.5 percent ownership fraction at Hayden 1 (or 44 MW) and a 12.6 percent ownership fraction at Hayden 2 (or 13 MW).[158] The units are majority owned and operated by Public Service Company of Colorado ("PSCo"). For perspective, at these fractions, the total SCR projects at Hayden 1 and 2 were large-scale projects, at [redacted] and [redacted], respectively.[159]

While the SCRs are ultimately a requirement under the Regional Haze Rule, the Regional Haze rule requirement post-dates a series of fleet-wide decisions made by PSCo, in which PacifiCorp simply followed PSCo's elections. In my opinion, this passive role was unjustifiable given the magnitude of the SCR retrofits, and lies in stark contrast with an evaluation of the project conducted by PacifiCorp.

[156] PAC/800 at Teply/48:4-51:14.
[157] *Id.* at Teply/24:15-19 [redacted] for SCR at Hayden 1, and $[redacted] for SCR at Hayden 2).
[158] *Id.* at Teply/50:10.
[159] Author's calculation. PacifiCorp project cost divided by ownership fraction.

Mr. Teply provided a few key dates of the Hayden project, but like all Regional Haze projects, timelines are important in understanding drivers and opportunities for alternative decisions. In addition, several of Mr. Teply's dates were incorrect. Below, I compile a more complete and corrected timeline of the Hayden SCR project.

Table 1. Timeline and milestones for Hayden Unit 1 and 2 SCR decisions and installation

Date	Milestone
April 19, 2010	Colorado Clean Air Clean Jobs Act is passed (HB 10-1365)
April 21, 2010	Colorado PUC opens Emission Reduction Plan docket, 10M-245E
August 13, 2010	PSCo submits Emissions Reduction Plan to Colorado PUC, including a proposal to install SCR at Hayden by the end of 2016.[160]
December 9, 2010	Colorado PUC determines a need for SCR at Hayden (Colorado PUC Order C10-1328)[161]
November 14, 2011	PSCo applies for CPCN in Colorado (Colorado PUC docket 11A-917E) PSCo announces that it has signed a new long-term coal contract[162] with Peabody coal. Contract is [redacted][163] for sixteen-years, expiring December 1, 2027[164]
July 18, 2012	Colorado PUC approves PSCo CPCN for SCR at Hayden (Colo PUC Order C12-0843)
November 18, 2012	PacifiCorp runs internal analysis [redacted] in retrofitting Hayden 1.[165] No explicit analysis of Hayden 2.
November 29, 2012	[redacted]
November 30, 2012	[redacted]
December 31, 2012	EPA's approval of Colorado Regional Haze SIP
January 30, 2013	Effective date for EPA's approval of Colo. SIP
June 1, 2013	[redacted][169]
May, 2015	Unit 1 in-service
August, 2015	Unit 2 in-service

[160] Public Service Company of Colorado's Notice of Filing, *In the Matter of Commission Consideration of Public Service Company of Colorado Plan In Compliance With House Bill 10-1365, "Clean Air - Clean Jobs Act."*, Docket No. 10M-245E, at 4 (Colo. Pub. Util. Comm'n Aug. 13, 2010).
[161] Corrects Mr. Teply's date of January 26, 2011. PAC/800 at Teply/49:14.
[162] Direct Testimony of Susan Arigoni on Behalf of PSCo, I*n the Matter of the Application of Public Service Company of Colorado for a Certificate Of Public Convenience and Necessity for the Hayden Emissions Control Project*, Docket No. 11A-917E at 12: 12-14 (Colo. Pub. Util. Comm'n Nov. 14, 2011) [hereinafter "Arigoni Direct Testimony"] (attached as Exhibit Sierra Club/120).
[163] *See* PacifiCorp, [redacted] at 4 (Aug. 5, 2014) (provided as a confidential attachment to PacifiCorp Response to Sierra Club 2.6 [hereinafter "Hayden/Craig Confidential Workshop"] (attached as Exhibit Sierra Club/121).
[164] EIA Form 923, fuel receipts, EIA Form 923, *available at* https://www.eia.gov/electricity/data/eia923/.
[165] *See* Confidential Attachment "[redacted]" to PacifiCorp Response to Sierra Club Data Request 2.6(b) (summary A and B attached as Exhibit Sierra Club/ 122).
[166] *See* Confidential Attachment "[redacted]" to PacifiCorp Response to Sierra Club Data Request 2.4 [hereinafter "Confidential Hayden SCR Memo" (attached as Exhibit Sierra Club/123).
[167] *Id.*
[168] Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan, 77 Fed. Reg. 76871 (Dec. 31, 2012) (Corrects Mr. Teply's date of December 31, 2012.).
[169] *See* Confidential Attachment to PacifiCorp Response to Sierra Club Data Request Sierra Club 2.4 CONF/Hayden 1, [redacted] (attached as Exhibit Sierra Club/124).

Q What's the relevance of the Colorado Clean Air Clean Jobs Act ("CACJA")?

A The CACJA was a unique Colorado state program to encourage the state's utilities to reduce air pollution through a combination of unit retirements and retrofits. The bill contemplated the state's need to propose an implementation plan for EPA's regional haze rule, and proposed that a "coordinated" approach to emissions reductions would be superior for the state, rather than a piecemeal approach.[170]

Importantly, CACJA did not mandate specific controls or emissions reductions at specific units. Rather it identified that the two investor-owned utilities, Black Hills and PSCo, should submit plans to the Colorado Public Utilities Commission ("PUC") proposing emissions reductions across their entire fleets. If the plans were pre-approved by the Colorado PUC, the utilities would be legislatively entitled to earn a return on any investments, or costs stranded through unit retirement.

The incentive is described by a PSCo witness in that utility's subsequent CPCN.

> The CACJA pushed two investor owned utilities (Black Hills and Public Service) to invest significant capital and retire existing plants for the greater good of the people of Colorado. In exchange, the companies were assured that they would recover their prudently incurred costs.[171]

The Colorado legislature set up a mechanism to provide an incentive to achieve rapid emissions reductions from Colorado's utilities through retrofits or retirements. While the plans required the approval of Colorado's utility

[170] Colo. Rev. Code § 40-3.2-202.
[171] Docket No. 11A-917E, Direct Testimony of Karen T. Hyde on Behalf of PSCo, at 15:1-5 (Colo Pub. Util. Comm'n Nov. 14, 2011).

commission, there were relatively few guardrails. And the incentive—an assurance of recovery—was not granted to the Colorado utilities' partners at co-owned power plants, like PacifiCorp at Hayden.

In other words, while PSCo was encouraged to create a comprehensive emissions reduction plan, of which Hayden was simply a small segment, these same incentives were not extended or even applicable to PacifiCorp.

Q Did PSCo's emissions reduction plan explicitly assess the value of installing retrofits at Hayden versus retiring the plant?

A No. In its 2010 application before the Colorado PUC, PSCo reviewed nine different scenarios. None of those scenarios assessed the retirement of Hayden. Rather, the scenarios baked in the assumption that the Hayden units would be retrofitted with SCRs. PSCo's assessed alternatives are shown below in Figure 10. When PSCo submitted supplemental testimony to the Colorado PUC in October 2010, it maintained the same assumptions with respect to Hayden.

Figure 10. Table from PSCo Emission Reduction Plan scenarios before the CoPUC, showing the assumption that Hayden would be retrofit with SCR in each scenario.[172]

Table JFH-2

	Scenarios								
Plant	Benchmark 1	Benchmark 1.1	2	3	4	5	6	6.1	7
Cherokee 1	SNCR 2014	SNCR 2014	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011
Cherokee 2	SNCR 2014	SNCR 2014	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011
Cherokee 3	SCR 2017	SCR 2017	SCR 2017	Shutdown 2017	SCR 2017	Shutdown 2017	Shutdown 2015	Shutdown 2017	Fuel Switch 2014 Shutdown 2015
Cherokee 4	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	**Shutdown 2018**	SNCR 2012 **Shutdown 2022**	Fuel Switch 2014 **Shutdown 2018**
Valmont 5	SCR 2015	SCR 2015	SCR 2015	SCR 2015	Shutdown 2017	Shutdown 2017	Shutdown 2017	Shutdown 2017	Fuel Switch 2013 Shutdown 2017
Pawnee [1]	SCR 2014	---	SCR 2014	SCR 2014	SCR 2014	SCR 2014	SCR 2014	SCR 2014	SCR 2014
Hayden 1 [1]	SCR 2015	---	SCR 2015	SCR 2015	SCR 2015	SCR 2015	SCR 2015	SCR 2015	SCR 2015
Hayden 2 [1]	SCR 2016	---	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016
Retired MW Controlled MW	0 1645	0 903	213 1432	365 1280	399 1246	551 1094	903 742	903 742	903 742
Total MW	**1645**	**903**	**1645**	**1645**	**1645**	**1645**	**1645**	**1645**	**1645**
% NOx reduction 2018[3]	72%	70%	81%	83%	83%	85%	69%	76%	84%
% Nox reduction when all actions complete[3]	72%	70%	81%	83%	83%	85%	89%	89%	89%
End of Year Convention => Action occurs at end of year listed									

Notes:
(1) Analyses also performed with no emission controls on Pawnee or Hayden
(2) Actions in Bold font occur beyond December 31, 2017
(3) Low NOx burner upgrades on Cherokee 2 and 4, Hayden 1 and 2, Pawnee 1 and Valmont 5 are included in the NOx reductions.

Q Did PacifiCorp have a choice in the matter with respect to PSCo's emission reduction plan under the CACJA?

A Yes. Arguably, PSCo's interest in creating an approvable plan for its own Commission should have been substantially negotiated with PacifiCorp, and subject to PacifiCorp's approval at the time that PSCo was seeking to make a commitment. PacifiCorp bore a due diligence responsibility at every turn with respect to its ownership share of Hayden.

[172] Docket No. 10M-245E, Direct Testimony of James Hill on Behalf of PSCo, at 6. Figure JFH-2 (Colo. Pub. Util. Comm'n Aug. 13, 2010) (attached as Exhibit Sierra Club/125).

Q Is there evidence that PacifiCorp sought to negotiate with PSCo with respect to its decision to retrofit Hayden with SCRs as part of its CACJA emissions reduction plan?

A No. Sierra Club asked PacifiCorp to identify and then "provide any analyses, assessments, presentations, memoranda, communications or the like provided by PSCo to PacifiCorp regarding its assessment that the installation of SCR at Hayden Units 1-2 were in the best interests of customers."[173] The only information PacifiCorp provided was a series of invoices and change orders for the actual SCR projects, devoid of any meaningful information aside from incurred or projected costs.[174] PacifiCorp neither identified nor produced any documents prior to May 2, 2011.

Q Do the documents from PSCo provide any basis for the retrofits?

A No. These documents simply provide a description stating that they are consistent with Xcel Energy's (a.k.a PSCo's) emission reduction plan under the CACJA.[175]

[173] Sierra Club/102, Sierra Club Data Request to PacifiCorp 2.4(d).
[174] *See* Confidential Attachments to PacifiCorp Response to Sierra Club Data Request 2.4.
[175] Specifically, each document bears only the following description, if a description is provided: "On December 15, 2010 the Colorado Public Utilities Commission issued a formal written ruling of the commission's decision on Xcel Energy's emissions-reduction plan to meet Colorado's Clean Air-Clean Jobs Act. The plan proposed to retrofit about 450 MW of coal-fired generation at the Hayden power plants with additional emission control technology. The objective of this proposal is to install SCR controls at Hayden Unit 1 [2] for emission reduction purposes."

Q Do the documents from PSCo provide any justification, benefits, or risk assessments for the retrofits?

A No. The section of the forms that would otherwise be used to describe justification, benefits, and risks are either blank or state "meet environmental compliance requirements."

Q Do the documents from PSCo provide any discussion of alternatives?

A No. The section of the forms that would otherwise be used to describe alternatives are blank.

Q Does PacifiCorp's correspondence with PSCo indicate any inquiry on the value, benefit, or risks of the projects?

A No. While PacifiCorp provided a set of email correspondence between PSCo and PacifiCorp, the entire correspondence is dedicated to obtaining signatures on work orders.

Q Mr. Teply testified that "[o]n January 26, 2011, the Colorado Public Utilities Commission approved the installation of SCR systems on Hayden Units 1-2."[176] Did that order establish an enforceable deadline for the SCRs?

A No. The order, dated December 9, 2010, simply approved the elements of PSCo's emissions reduction plan, providing a cost recovery assurance for PSCo under the Clean Air-Clean Jobs act. It did not establish an enforceable deadline or requirement.

[176] PAC/800 at Teply/49:14-17.

Q You noted that on November 11, 2014 PSCo's application for a CPCN before the CoPUC, stated that it had signed a new coal contract for Hayden, and that the contract extended to 2027. What's the relationship between the CPCN application and this coal contract?

A The signing of a major long-term fuel contract is paramount to a capital commitment, requiring its own in-depth assessment. While this is not an assessment of Colorado's process, I find it extraordinary (a) that 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. Assessing the value of the coal contract and the SCR separately, and without respect to each other—after all, both the SCR and the contract would have been avoidable if the plant were to have shut down—is inappropriate and inconsistent with reasonable utility practice.

It is further remarkable that the PSCo witness describing the newly-signed contract admitted that it would be 24 percent more expensive (on a levelized cost basis, 2012-2018) than anticipated when the Company put together its emissions reduction plan.[177] And yet neither the cost increase nor the decoupling of the coal contract from the PSCo decision seem to have been of concern PacifiCorp.

[177] Sierra Club/120, Arigoni Direct Testimony at 12:1. Author's calculation, based on notional 7% nominal discount rate.

Q Did PacifiCorp have a role in evaluating or negotiating that new fuel contract in November 2011?

A According to PSCo, yes. In Arigoni's testimony before the Colorado PUC in the CPCN, PSCo's witness on the fuel cost increase testified that the decision on both the SCR and the coal contract were made in consultation with PacifiCorp:

> Public Service jointly owns Hayden with two other utilities: PacifiCorp and Salt River Project Agricultural and Irrigation and Power District ("SRP"). Although Public Service is the Operating Agent for Hayden, major decisions, like coal supply and the installation of emissions controls have been jointly made by the participants. Therefore, Public Service has worked with SRP and PacifiCorp to negotiate the coal-supply arrangements for Hayden.[178]

Q Was the Colorado PUC's approval of PSCo's CPCN in July 2012 the final point at which a decision was irrevocable?

A Not at all. PSCo's CPCN was simply an indication that PSCo had a reasonable chance of receiving cost recovery if it elected to move forward with the SCRs under the Regional Haze rule. It did not eliminate the need for ongoing diligence by the operator, or ongoing scrutiny by PacifiCorp.

Q Mr. Teply testified that "the Hayden Units 1-2 SCRs were required by the State of Colorado's Regional Haze SIP to be installed no later than December 31, 2016."[179] Is he correct?

A No. While Colorado's Regional Haze SIP identified emission limits for Hayden consistent with SCR, it did not identify a specific deadline of December 31, 2016. That deadline was established by PSCo as a target in its Emissions Reduction

[178] Sierra Club/120, Arigoni Direct Testimony at 2:19 -3:2.
[179] PAC/800 at Teply/48:18-19.

Plan, but was not specifically enforceable as a deadline under the federal Clean Air Act.

Q Did EPA's final approval of Colorado's Regional Haze SIP identify an enforceable deadline of December 31, 2016?

A No. EPA issued both a proposed and final regional haze rule for Colorado. In both instances EPA was clear that the facilities under consideration would have a five year deadline to retrofit coal units.[180] EPA's approval of Colorado's Regional Haze SIP had an effective date of January 30, 2013.[181] Therefore, the binding installation date was January 30, 2018—more than a year after PSCo's internally-driven date.

Q Did PacifiCorp conduct an independent assessment of the Hayden SCR decision after the CPCN was issued to PSCo?

A Yes. While Mr. Teply described PacifiCorp's the independent analysis on the Craig SCRs, his testimony did not include details of a PacifiCorp analysis of the Hayden SCR projects. In response to discovery, PacifiCorp stated:

> PacifiCorp independently assessed and analyzed its options under the participation agreement for the Hayden Unit 1 and Hayden Unit 2 SCR system projects. The analysis contains commercially sensitive and highly confidential information. The analysis ultimately had no bearing on the Company's Hayden Unit 1 and Hayden Unit 2 SCR systems installation assessment, with the equipment being installed to comply with the Colorado Clean Air-

[180] Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan. Proposed Rule, 77 Fed. Reg. 18052, 18056 (Mar. 26, 2012) ("Once a state has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five years *after the date of EPA approval of the RH SIP*.") (Emphasis added).
[181] 77 Fed. Reg.76871.

Clean Jobs Act under the purview of the Colorado Public Utilities Commission.[182]

[redacted]

Q What was the outcome of PacifiCorp's assessment?

A [redacted]

[182] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 2.4(e).
[183] *See* Sierra Club/122, Confidential Hayden 1 PVRR Study.

[redacted][184]

Q What actions did PacifiCorp take as a result of these findings?

A PacifiCorp took no actions at all. According to the Company's response to discovery, "the analysis ultimately had no bearing on the Company's Hayden Unit 1 and Hayden Unit 2 SCR systems installation assessment."[185] [redacted] In my opinion, this was an error.

Q Did the Company's Hayden analysis independently assess the value of retrofitting Hayden 2?

A No. [redacted] the assessment did not review the independent economics of retrofitting Hayden 2.

Q Why did the Company not act on its findings that [redacted]?

A The Company has provided two different rationales, as I discuss below.

- [redacted]

[184] *See id.*, [redacted].
[185] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 2.4(e).

- [redacted]

Both of these rationales were flawed, and showed a lack of oversight, rather than a carefully considered analysis of ratepayer impacts. I address them in reverse order.

a. PACIFICORP'S FLAWED ASSESSMENT OF THE [redacted] AT HAYDEN

Q How did you learn that the Company had assessed the costs of [redacted] the value of retiring Hayden 1?

A In August, 2014 the Company conducted a confidential workshop to review its existing analysis on the planned Craig and Hayden environmental investments.[186] [redacted]

[186] *See* PacifiCorp, *2015 Integrated Resource Plan*, Vol. II, App. B at 29 (filed Mar. 31, 2015), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html. A redacted form of the presentation is available in Docket No. LC 57 as PacifiCorp's Response to a Ruling Requiring Redesignation of the Workshop Presentation, (Oct. 23, 2014), *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc57hac124711.pdf.
[187] Sierra Club/121, Hayden/Craig Confidential Workshop at 8.
[188] *Id.*

[redacted]

[redacted]

Q To whom was this presentation directed?

A The presentation on the Craig and Hayden analyses was directed to this Commission, and intervenors in the Company's 2013 IRP subject to confidentiality provisions.

Q Did the Company present this Commission with all of the facts concerning the value of closing Hayden?

A No. [redacted]

In addition, in that workshop and accompanying materials, the Company failed to disclose to the Commission that the Hayden coal contract had been signed in late 2011, with PacifiCorp's consent—just a year before the PacifiCorp acquiesced to the retrofits.

Again, it is remarkable that the Company so readily signed a coal contract to extend the life of the Hayden units through at least 2027 [redacted]

[189] *Id.* at 4.
[190] *Id.* at 8.
[191] *See* Sierra Club/122, Confidential Hayden 1 PVRR Study , [redacted].

[redacted]. As far as I'm aware, there was no time at which the Company assessed—or had assessed by PSCo—whether the plan to both extend the coal contract and retrofit Hayden with SCR was better than seeking a retirement of the unit.

[redacted]

A [redacted]

[redacted]

In that same presentation to this Commission, the Company claimed [redacted][192] I address this next.

b. PACIFICORP'S FLAWED ASSESSMENT OF ITS [redacted] FOR THE SCRS AT HAYDEN

Q How did you learn that the Company had concluded [redacted] moving forward with the retrofits?

A [redacted]

[redacted]

[192] *See* Sierra Club/121, Hayden/Craig Confidential Workshop at 5.
[193] In 2012, Michael Dunn was President and CEO of PacifiCorp. Today he is the CEO of Williams, an oil production company. PacifiCorp witness Mr. Teply is now also at Williams.

[redacted][194]

[redacted]

Q Do you agree that PacifiCorp [redacted]

A No. PSCo's move to install SCR at Hayden was not consistent with generally accepted practices for electric utilities. There are several ways in which the PSCo's decision was demonstrably inconsistent, [redacted].

- PSCo should have identified the latest possible compliance date available under the law, and sought to maximize optionality by assessing the high

[194] Sierra Club/123, Confidential Hayden SCR Memo.
[195] *Id.*

cost retrofits as late as feasible. Instead, PSCo moved forward to sign a contract to install the SCRs with Hitachi before EPA had even finalized the SIP (refer to Table 1, above), establishing an installation deadline inconsistent with federal law.

- PSCo's election to install SCR at Hayden was not a cost-effectiveness decision. As shown in Figure 10, PSCo did not assess alternative scenarios in which Hayden was retired when it created its 2010 emissions reduction plan. When PSCo applied for CPCN in 2011, it did not conduct a cost effectiveness assessment at all.
- Any assessments conducted by PSCo in 2010 or 2011 would have been woefully out of date by the time PSCo was seeking to move forward on the retrofit [redacted]. As shown in the Jim Bridger section of my testimony, forward gas prices were consistently falling through 2011 and 2012. [redacted]
- 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.. Like at Jim Bridger, PSCo had alternative options to comply with the Regional Haze rule, including retirement rather than installation, or a commitment to retire at a later date, the effect of which would have shown the SCRs to not be cost-effective under the Regional Haze Rule. PSCo examined neither option.

- The SCR retrofits at Hayden were not specifically required under the Clean Air Clean Jobs Act, which instead sought a system-wide approach to achieving emissions reductions. Such reductions could have either been achieved at other facilities or through unit retirements.

Overall, I believe that PacifiCorp had a number of options at its disposal to effectively contest PSCo's decision to move forward with the SCRs, and succeed in appealing that decision as inconsistent with generally accepted practices for electric utilities.

Q [redacted]

A [redacted]

Q Do you have any other opinions on PacifiCorp's November 2012 assessment concerning the Hayden SCRs?

A Yes, I have several.

- First, the Company's assessment failed to review the independent value, or cost, of retrofitting Hayden 2, but focused instead on Hayden 1 only.[196]
- Second, the Company's assessment failed to review the joint value, or cost, of retrofitting or retiring both Hayden 1 and Hayden 2[redacted]

[196] *See* public version of workshop presentation, available in Docket No. LC 57 as PacifiCorp's Response to a Ruling Requiring Redesignation of the Workshop Presentation (Oct. 23, 2014), *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc57hac124711.pdf.

[redacted]

[redacted].

- Third, the Company's analysis contained a critical formula error [redacted]

[redacted]

Q Please explain this formula error, and what it portends for the Company's analysis of the Hayden and Craig retrofits.

A [redacted][197]

[redacted]

197 [redacted]

Confidential Figure 11. November 2012 Assessment of Hayden and Craig value, as conducted by PacifiCorp,[198] and as corrected.



Q Please summarize your findings with respect to the Company's decisions for the Hayden SCR retrofits.

A Overall, the Company failed to intervene effectively or meaningfully with respect to its participation and co-ownership of Hayden for either the SCRs or the election to move forward on a long-term fuel contract.

4. The Company failed to engage successfully or meaningfully in PSCo's 2010 emission reduction plan, whereby PSCo opted to install SCRs at Hayden, committing PacifiCorp to that same course of action.

5. The Company failed to assess the joint cost of signing a new coal contract for Hayden and moving forward on the SCRs. By decoupling the SCR decision from the coal contract decision, the Company made two separate elections that should have been made jointly.

[198] Sierra Club/122, Confidential Hayden 1 PVRR Study, line "[redacted]".

6. The Company 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.
7. The Company failed to pursue an alternative retirement strategy with PSCo, instead incorrectly agreeing to—[redacted]—an unenforceable premature compliance deadline.
8. The Company's assessment of [redacted], but the Company elected to ignore this outcome and signaled its approval to PSCo.
9. [redacted].
10. [redacted].
11. [redacted].
12. [redacted].

The Company acted imprudently by failing to take action to prevent the installation of the SCRs at Hayden 1 & 2. Because the cost of alternatives has fallen substantially since PacifiCorp make this decision, ratepayers have experienced losses greater than the cost of the retrofits themselves. I recommend that the Commission disallow the costs of the Hayden retrofits on an Oregon allocation basis, or [redacted]. In addition, I recommend that the Commission consider disallowing costs associated with the [redacted] Hayden coal contract entered into in 2011.

Q Does this conclude your testimony?

It does.

Docket No. UE 374
Exhibit Sierra Club/101
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 101

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Curriculum Vitae of Jeremy Fisher, PhD

Jeremy Fisher, PhD.
Senior Strategy and Technical Advisor

Sierra Club. 2101 Webster Avenue. Oakland, California. Suite 1300.
415-977-5536
Jeremy.Fisher@sierraclub.org

EDUCATION

BROWN UNIVERSITY Providence, Rhode Island
Doctor of Philosophy in Geological Sciences (2006)
Master of Science in Geological Sciences (2003)

UNIVERSITY OF MARYLAND College Park, Maryland
Bachelor of Science in Geology (2001)
Bachelor of Science in Geography (2001)

PROFESSIONAL EXPERIENCE

SIERRA CLUB Oakland, California
Senior Advisor for Strategic Research and Development (2019-present)

Senior Strategy and Technical Advisor (2017-December 2019)

Provides detailed expertise on energy system issues and strategic engagement with utilities, regulatory commission, and partners. Research and development on cutting edge energy system economic issues, supports legal and campaign staff at Sierra Club; provides oversight to consulting practices on energy issues.

SYNAPSE ENERGY ECONOMICS Cambridge, Massachusetts
Principal Associate (2013-2017); Scientist (2007-2013)

Consulted on economic analysis of climate change and energy, carbon, and emissions policies. Developed successful clean energy regulatory strategy. Provides detailed technical and strategic analysis on behalf of public interest groups in US. Provides training to regulators on best practices in energy system planning. Develops quantitative evaluations of regional climate change impact, long- and short-term electric industry planning, carbon reduction strategies, and emissions compliance programs. Lead investigator on avoided emissions tool (AVERT) for US EPA; collaborator on health benefits assessments.

TULANE UNIVERSITY New Orleans, Louisiana
Postdoctoral Researcher (2006-2007)

Modeled carbon balance in forest ecosystems through satellite data and dynamic models. Developed new techniques to assess large-scale forest morbidity and mortality. Tracking impacts of Hurricane Katrina (US Gulf Coast) and large-scale disturbances in Amazon basin. (Brazil).

BROWN UNIVERSITY Providence, Rhode Island
Research Assistant (2001-2006)

Tracked impact of climate change on New England forests from satellites. Worked with West African communities to determine impact of climate change and practice on landscape. Modeled coastal power plant effluent from satellite data.

FELLOWSHIPS & AWARDS

- *Visiting Fellow,* Watson Institute for International Studies, Brown University, 2007
- *Fellow*, National Science Foundation East Asia Summer Institute (EASI), 2003
- *Fellow*, Henry Luce Foundation at the Watson Institute for International Studies, Brown University, 2003

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Michigan Public Service Commission (Case No. U-20529). Direct testimony in Indiana Michigan's Power Supply Cost Recovery Plan regarding participation in the Ohio Valley Electric Cooperative. On behalf of Sierra Club. May 11, 2020.

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United States Court of Appeals for the Second Circuit (Case 19-3652(L)). Declaration in support of Sierra Club's action to compel the Secretary of Energy to maintain lighting efficiency standards. On behalf of Sierra Club, March 18, 2020.

New Mexico Public Regulation Commission (Case No. 19-00018-UT). Rebuttal testimony in support of Public Service New Mexico's proposal to abandon San Juan power plant, and use of securitization as a recovery mechanism. On behalf of Sierra Club. November 15, 2019.

Kentucky Public Service Commission (Dockets 2018-00294/2018-00295). Direct testimony in Kentucky Utilities / Louisville Gas and Electric's adjustment of rates regarding participation in the Ohio Valley Electric Cooperative. On behalf of Sierra Club. January 16, 2019.

Superior Court of Washington for Thurston County (No. 18-2-03640-34). Declaration in support of Sierra Club opposing PacifiCorp motion for relief to keep certain materials related to the economics of PacifiCorp's coal fleet confidential. On behalf of Sierra Club. September 7, 2018.

United States District Court for the District of Columbia (Civil Action 17-2700-EGS). Declaration in support of Sierra Club's action to compel the Secretary of Energy to complete energy efficiency standards for manufactured housing. On behalf of Sierra Club. June 29, 2018.

Public Utilities Commission of Ohio (Docket 17-32-EL-AIR): Direct testimony in Duke Energy Ohio's request for a rider to include the costs of Ohio Valley Electric Corporation contract costs into rates. On behalf of Sierra Club. June 25, 2018.

California Public Utilities Commission (Investigation 17-04-019): Direct testimony regarding PacifiCorp's compliance with California's Emissions Performance Standard. On behalf of Sierra Club. February 7, 2018.

Mississippi Public Service Commission (Docket No. 2017-AD-112): Direct testimony regarding settlement with Mississippi Power Company on value of Kemper County Combined Cycle plant. On behalf of Sierra Club. October 23, 2017.

Utah Public Service Commission (Docket 14-035-114): Direct and surrebuttal testimonies in the investigation into the costs and benefits of PacifiCorp's proposed Net Metering program, with respect to long-term resource value and environmental benefits. On behalf of Heal Utah. June 8, 2017.

Indiana Utility Regulatory Commission (Cause No. 44872): Direct and rebuttal testimonies regarding Northern Indiana Public Service Company's application for a Certificate of Public Convenience and Necessity for environmental compliance projects at Schahfer units 14 & 15 and Michigan City unit 12. On behalf of Sierra Club. April 3, 2017.

Indiana Utility Regulatory Commission (Cause No. 44871): Direct and rebuttal testimonies regarding Indiana Michigan Company's application for a Certificate of Public Convenience and Necessity to install Selective Catalytic Reduction at Rockport Power Plant Unit 2. On behalf of Citizens Action Coalition of Indiana, Sierra Club, and Valley Watch. February 3, 2017.

Public Utilities Commission of Nevada (Docket Nos. 16-07001, 16-07007, and 16-08027): Direct testimony regarding the economic viability of the North Valmy coal plant. On behalf of Sierra Club. September 30, 2016.

California Public Utilities Commission (Docket 15-09-007): Direct testimony regarding PacifiCorp's application for authority to sell Utah mining assets on a post-hoc basis. On behalf of Sierra Club. July 11, 2016.

Washington Utilities and Transportation Commission (Docket UE-152253): Response, cross-answer, and supplementary cross-answer testimony regarding the general rate case on behalf of Pacific Power & Light Company. On behalf of Sierra Club. June 1, 2016.

Georgia Public Service Commission (Docket 40161): Direct testimony regarding Georgia Power Company's 2016 Integrated Resource Plan. On behalf of Sierra Club. May 18, 2016.

Oregon Public Utility Commission (Docket UM-1712): Direct testimony regarding PacifiCorp's application for approval of Deer Creek Mine transaction. On behalf of Sierra Club. March 5, 2015.

Oklahoma Corporation Commission (Case No. PUD 201400): Direct and rebuttal testimony comparing the modeling performed by Oklahoma Gas & Electric in support of its request for authorization and cost recovery of a Clean Air Act compliance plan and Mustang modernization against best practices in resource planning. On behalf of Sierra Club. December 16, 2014 and January 26, 2015.

New Mexico Public Regulation Commission (Case 12-00390-UT): Direct and surrebuttal testimony evaluating the economic modeling performed by Public Service Company of New Mexico in support of its application for certificate of public convenience and necessity for the acquisition of San Juan Generating Station and Palo Verde units. On behalf of New Energy Economy. August 29, 2014; December 29, 2014.

Wyoming Public Service Commission (Docket No. 20000-446-ER-14): Direct testimony in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Wyoming approximately $36.1 million per year or 5.3 percent. On behalf of Sierra Club. July 25, 2014.

Indiana Utility Regulatory Commissions (Cause No. 44446): Direct testimony evaluating the economic modeling performed on behalf of Vectren South in support of its application for certificate of public convenience and necessity for various retrofits at Brown 1 & 2, Culley 3 and Culley plant, and Warrick 4. On behalf of Sierra Club, Citizens Action Coalition, and Valley Watch. May 28, 2014.

Utah Public Service Commission (Docket No. 13-035-184): Direct testimony In the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Utah and for approval of its proposed electric service schedules and electric service regulations. On behalf of Sierra Club. May 1, 2014.

Louisiana Public Service Commission (Docket No. U-32507): Direct and cross answering testimony regarding the application of Cleco Power LLC for: (i) authorization to install emissions control equipment at certain of its generating facilities in order to comply with the federal national emissions standards for hazardous air pollutants from coal and oil-fired electric steam units rule; and (ii) authorization to recover the costs associated with the emissions control equipment in jurisdictional rates. On behalf of Sierra Club. November 8, 2013 and December 9, 2013.

Nevada Public Utilities Commission (Docket No. 13-07021): Direct testimony regarding a joint application of Nevada Power Company d/b/a NV Energy, Sierra Pacific Power Company d/b/a NV Energy (referenced together as "NV Energy, Inc.") and MidAmerican Energy Holdings Company ("MidAmerican") for approval of a merger of NV Energy, Inc. with MidAmerican. On behalf of Sierra Club. October 24, 2013.

Indiana Utility Regulatory Commission (Cause No. 44339): Direct testimony in the matter of Indianapolis Power & Light Company's application for a Certificate of Public Convenience and Necessity for the construction of a combined cycle gas turbine generation facility. On behalf of Citizens Action Coalition of Indiana. August 22, 2013.

Indiana Utility Regulatory Commission (Cause No. 44242): Direct and surrebuttal testimony regarding Indianapolis Power & Light Company's petition for approval of clean energy projects and qualified pollution control property. On behalf of Sierra Club. January 28, 2013; April 3, 2013.

Wyoming Public Service Commission (Docket 2000-418-EA-12): Direct testimony regarding the application of PacifiCorp for approval of a certificate of public convenience and necessity to construct selective catalytic reduction systems on the Jim Bridger Units 3 and 4. On behalf of Sierra Club. February 1, 2013.

Public Service Commission of Wisconsin (Docket No. 6690-CE-197): Direct, rebuttal, and surrebuttal testimony regarding Wisconsin Public Service Corporation's application for authority to construct a multi-pollutant control technology system for Unit 3 of Weston Generating Station. On behalf of Clean Wisconsin. Direct testimony submitted November 15, 2012, rebuttal testimony submitted December 14, 2012, surrebuttal testimony submitted January 7, 2013.

Utah Public Service Commission (Docket 12-035-92): Direct, surrebuttal, and cross-answering testimony regarding Rocky Mountain Power's request for approval to construct Selective Catalytic Reduction systems at Jim Bridger units 3 and 4. On behalf of Sierra Club. November 30, 2012.

Oregon Public Utility Commission (Docket UE 246): Direct testimony in the matter of PacifiCorp's filing of revised tariff schedules for electric service in Oregon. On behalf of Sierra Club. June 20, 2012.

Kentucky Public Service Commission (Docket 2011-00401): Direct testimony regarding the application of Kentucky Power Company for approval of its 2011 environmental compliance plan, for approval of its amended environmental cost recovery surcharge tariff, and for the granting of a certificate of public convenience and necessity for the construction and acquisition of related facilities. On behalf of Sierra Club. March 12, 2012.

Kentucky Public Service Commission (Dockets 2011-00161/2011-00162): Direct testimony regarding the application of Kentucky Utilities/Louisville Gas and Electric Company for certificates of public convenience and necessity and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

Kansas Corporation Commission (Docket 11-KCPE-581-PRE): Direct testimony in the matter of the petition of Kansas City Power & Light (KCP&L) for determination of the ratemaking principles and treatment that will apply to the recovery in rates of the cost to be incurred by KCP&L for certain electric generating facilities under K.S.A. 66-1239. On behalf of Sierra Club. June 3, 2011.

Utah Public Service Commission (Docket 10-035-124): Direct testimony in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Utah and approval of its proposal electric service schedules and electric service regulations. On behalf of Sierra Club. May 26, 2011.

Wyoming Public Service Commission (Docket 20000-384-ER-10): Direct testimony in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility rates in Wyoming approximately $97.9 million per year or an average overall increase of 17.3 percent. On behalf of Powder River Basin Resource Council. April 11, 2011.

Docket No. UE 374
Exhibit Sierra Club/102
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 102

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Public Discovery Responses

Exhibit Sierra Club/102

Selected Public Responses to Sierra Club Data Requests

1. PacifiCorp's Response to Sierra Club Data Request 1.1
2 PacifiCorp Response to Sierra Club Data Request 1.3
3. PacifiCorp Response to Sierra Club Data Request 1.4
4. PacifiCorp Response to Sierra Club Data Request 1.5
5 PacifiCorp Response to Sierra Club Data Request 1.6
6. PacifiCorp Response to Sierra Club Data Request 1.8
7. PacifiCorp Response to Sierra Club Data Request 2.4

UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.1

Sierra Club Data Request 1.1

Refer to the Direct Testimony of Rick Link, page 86 at 26 through page 87 at 2. "PacifiCorp conducted its economic analysis as part of its 2013 IRP. PacifiCorp decided in May 2013 to move forward with SCR emissions control systems for Jim Bridger Units 3 and 4 based on this analysis."

(a) State the date on which the Company decided that the 2013 IRP provided sufficient information for the Company to decide to "move forward" with SCRs at Jim Bridger 3 and 4.

(b) Provide all correspondence, memos, orders, decision documents, directives, or the like by PacifiCorp management during or around May 2013 documenting PacifiCorp's decision "to move forward" with SCR emissions control systems.

(c) Confirm or deny: the May 2013 directive "to move forward" with the SCR systems included signing a Limited Notice to Proceed (LNTP) with the contractors of the SCR systems. If denied, identify and produce the directive the Company relied on to make the decision to "move forward."

(d) Provide all correspondence, orders, memos, decision documents, directives, or the like by PacifiCorp management during or around May 2013 documenting the fact that the decision to proceed with the SCR projects was based on PacifiCorp's 2013 IRP.

(e) Confirm or deny: PacifiCorp filed a request for Certificate of Public Convenience and Necessity (CPCN) for the SCRs at Jim Bridger in Wyoming Public Service Commission (Wyoming PSC) Docket No. 20000-418-EA-12.

(f) Confirm or deny: the May 2013 directive "to move forward" with the SCR systems followed approval of the CPCN by the Wyoming PSC.

(g) Provide the unredacted direct and rebuttal testimonies of Mr. Rick Link and Mr. Chad Teply in Wyoming Docket No. 20000-418-EA-12 with respect to the Bridger SCRs.

(h) Confirm or deny: the CPCN application in Wyoming Docket No. 20000-418-EA-12 was based on an Official Forward Price Curve (OFPC) dated December 2011.

Response to Sierra Club Data Request 1.1

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
March 31, 2020
Sierra Club Data Request 1.1

(a) The decision to move forward with the installation of selective catalytic reduction (SCR) emissions control systems was finalized with the approval of an appropriation approval request (APR) on May 30, 2013.

(b) Please refer to Confidential Attachment SC 1.1-1 which provides the following key PacifiCorp decision documents:

1. Confidential Project Proposal – APR 10003396, Jim Bridger Unit 3 SCR System Implementation Phase, May 20, 2013.

2. Confidential Project Proposal – APR 10003398, Jim Bridger Unit 4 SCR System Implementation Phase, May 20, 2013.

3. Confidential Jim Bridger Unit 3 and Jim Bridger Unit 4 SCR Systems Approval Request, May 22, 2013.

4. Confidential Letter to Idaho Power Company, June 5, 2013.

(c) Confirmed. A limited notice to proceed concept was included in its engineer, procure, and construct contract for the Jim Bridger Unit 3 and Jim Bridger 4 SCR projects.

(d) Please refer to the company's response to subpart (b) above. In addition, please refer to the company's response to Sierra Club Data Request 1.2 subpart (b).

(e) Confirmed. PacifiCorp filed a request for a certificate of public convenience and necessity (CPCN) for the SCRs at Jim Bridger Unit 3 and Jim Bridger Unit 4 with the Wyoming Public Service Commission (WPSC) in Docket 20000-418-EA-12.

(f) Confirmed. The May 2013 directive "to move forward" with the SCR systems followed the approval of the CPCN by the WPSC in Docket 20000-418-EA-12. Please refer to Attachment Sierra Club 1.1-2 which provides a copy of the WPSC's order dated May 29, 2013.

(g) PacifiCorp objects to this data request on the grounds that it is unduly burdensome for it to provide the requested documents given that the company is informed and believes that the information sought in the data request may already be in the possession of Sierra Club due to their participation in the out of state proceeding. If Sierra Club seeks to introduce confidential material from an out of state proceeding in this case, PacifiCorp urges Sierra Club to meet and confer with it to discuss the intended use of such documents. PacifiCorp expressly reserves all its rights to object to the introduction of such

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confidential material from out of state proceedings on all appropriate grounds.

(h) Yes, the CPCN application in Wyoming (Docket 20000-418-EA-12) used the December 2011 official forward price curve for the base case. Please refer to the direct testimony Rick T. Link, specifically Confidential Exhibit PAC/708. There were eight other price curves of the same vintage (low gas $16 carbon dioxide ($CO_2$,) high gas $16 CO_2, base gas $0 CO_2, base gas $34 CO_2, low gas $34 CO_2, high gas $0 CO_2) were used in the Jim Bridger Unit 3 and Jim Bridger Unit 4 SCR analysis to provide a range of results.

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.

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UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.3

Sierra Club Data Request 1.3

Refer to the Direct Testimony of Mr. Rick Link, page 106 at 19, with reference to the Full Notice to Proceed (FNTP).

(a) Provide a schedule of capital spending, by month, at each Jim Bridger SCR project as projected in or around September 2013.

(b) Provide a schedule of capital spending, by month, at each Jim Bridger SCR project as incurred.

(c) Provide the FNTP notice provided to the project contractors.

(d) State if the contract confirmed by the FNTP included termination provisions or damages for early termination after the FNTP, and if so, the nature of the early termination

(e) Provide the contract, including all materials necessary to calculate early termination costs.

(f) Provide an estimate of the early termination costs from the contractor that would have been incurred if the project were cancelled on December 31, 2013.

Response to Sierra Club Data Request 1.3

(a) Please refer to Confidential Attachment Sierra Club 1.3-1 for a copy of the Jim Bridger Unit 3 September 2013 direct cost month-by-month forecast schedule of spending, and a direct forecast of month-by-month spending for Jim Bridger Unit 4. Note: capital surcharge and Allowance for Funds Used During Construction (AFUDC) costs are not included in the attachment.

(b) Please refer to Confidential Attachment Sierra Club 1.3-2 for a copy of the Jim Bridger Unit 3 December 2016 direct cost month-by-month as-incurred schedule of spending, and the December 2017 as-incurred monthly direct cost spend summary for Jim Bridger Unit 4. Note: capital surcharge and AFUDC costs are not included in the attachment.

(c) Please refer to Confidential Attachment Sierra Club 1.3-3 for a copy of the Full Notice to Proceed (FNTP) provided to the engineer, procure, construct (EPC) contractor.

(d) PacifiCorp confirms that the EPC contract included FNTP termination rights and an associated cancellation schedule. The EPC contract is considered

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highly confidential and commercially sensitive. The company requests special handling. Please contact Matt McVee at (503) 813-5585 to make arrangements for review.

(e) The EPC contract is considered highly confidential and commercially sensitive. The company requests special handling. Please contact Matt McVee at (503) 813-5585 to make arrangements for review.

(f) The EPC contract is considered highly confidential and commercially sensitive. The company requests special handling. Please contact Matt McVee at (503) 813-5585 to make arrangements for review.

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UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.4

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).

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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

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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.

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UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.5

Sierra Club Data Request 1.5

Refer to the Direct Testimony of Mr. Rick Link, page 107, footnote 79 with respect to gas price forecasts from third parties.

(a) Provide the three third-party gas price forecasts "after September 2013" referred to above.

(b) Identify the third-party provider and the date the forecast was received by PacifiCorp.

(c) Provide the prior forecasts received from each of the three providers, identifying the provider and the date the forecast was received by PacifiCorp.

Response to Sierra Club Data Request 1.5

(a) Please refer to Confidential Attachment Sierra Club 1.5-1 for copies of the third party natural gas price forecasts "after September 2013." Note 1: in keeping with prior authorizations received in 2016 from the third party vendors, the provided information is limited to Henry Hub and Opal natural gas markets. Note 2: 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 with the permission of the relevant third party entities subject to the terms and conditions of the protective order/confidentiality agreement in this proceeding.

(b) The third party natural gas price forecasts received "after September 2013" are as follows:

- IHS CERA's long-term natural gas price forecast updates, as accessed by PacifiCorp on November 21, 2013.

- Wood Mackenzie's long-term biannual natural gas price forecast, as published on October 22, 2013.

- PIRA's long-term natural gas price forecast, as accessed December 11, 2013. Note: at this time, PIRA documents are not provided in Confidential Attachment Sierra Club 1.5-1 or Attachment Sierra Club 1.5-2; the company are awaiting permission to be granted by PIRA for the information to be shared external to the company. The company will update this response with the PIRA documents after permission to share has been received.

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
March 31, 2020
Sierra Club Data Request 1.5

(c) Please refer to Confidential Attachment Sierra Club 1.5-2 for copies of third party natural gas price forecasts (i.e., those considered when preparing the September 2013 official forward price curve providing both name of provider and vintage. Note 1: in keeping with prior authorizations received in 2016 from the third party vendors, the provided information is limited to Henry Hub and Opal natural gas markets. Note 2: 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 with the permission of the relevant third party entities subject to the terms and conditions of the protective order/confidentiality agreement in this proceeding.

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UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.6

Sierra Club Data Request 1.6

Refer to the Direct Testimony of Mr. Rick Link, page 94 at 3 with reference to the September 2012 OFPC, page 107 at 7 with reference to the September 2013 OFPC, and page 87 at 2-4 with respect to the completion timeline of the SCR projects.

(a) Confirm or deny: at the time of the September 2013 OFPC and at the time of the FNTP for the SCR projects, Mr. Link was the PacifiCorp employee responsible for the production of gas price forecasts relied upon by the Company. If denied, identify the employee at PacifiCorp ultimately responsible for the production of gas price forecasts relied upon by the Company.

(b) Confirm or deny: at the time of the September 2013 OFPC and at the time of the FNTP for the SCR projects, Mr. Link was the PacifiCorp employee responsible for the production of OFPC. If denied, identify the employee at PacifiCorp ultimately responsible for the production of OFPC relied upon by the Company.

(c) Provide each OFPC produced by PacifiCorp between December 2011 and December 2016, inclusive.

Response to Sierra Club Data Request 1.6

(a) Confirmed.

(b) Confirmed.

(c) Please refer to Attachment Sierra Club 1.6 which provides PacifiCorp's official forward price curves produced between December 2011 and December 2016.

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
March 31, 2020
Sierra Club Data Request 1.8

Sierra Club Data Request 1.8

Refer to PacifiCorp Senior Vice President Dana Ralston's public testimony in Washington Utilities and Transport Commission (WUTC) docket UE-152253 general rate case, supporting decision to install SCRs at Jim Bridger. Specifically, refer to Exhibit DR-1CT, the Rebuttal Testimony of Mr. Ralston, page 8 at 5 – 21 (unnumbered, to end of page), stating "there is no doubt that the October 2013 mine plan reflects changes between the surface and underground mining operations at BCC."

(a) Confirm or deny: On or around October 2013, the Bridger Coal Company produced a revised mine plan. If denied, correct the record accordingly.

(b) Provide the October 2013 mine plan from the Bridger Coal Company. Identify specific features revised from the mine plan and fueling strategy informing the Bridger SCR assessment.

(c) Provide Mr. Ralston's complete and unredacted rebuttal testimony in WUTC docket UE-152253, and supporting exhibits and work papers.

(d) Identify the date the analysis presented on page 8 of Mr. Ralston's rebuttal testimony was performed.

(e) Provide a fully unredacted copy of Order 12 in Washington Docket UE-152253.

Response to Sierra Club Data Request 1.8

(a) The Bridger Coal Company created an engineering mine plan dated October 4, 2013. However, operating costs based on this engineering plan were not complete and available until November 20, 2013.

(b) Please refer to Confidential Attachment Sierra Club 1.8 for the referenced October 2013 mine plan. Key mine plan assumption changes between the October 2013 mine plan and the mine plans used in the Jim Bridger selective catalytic reduction assessment are summarized as follows:

	Bridger Coal Company - Mine Plans		
	January 2013 4-Unit	January 2013 2-Unit	October 2013
Application/Purpose	2013 IRP	2013 IRP	2014 10 Year Budget
Key Operating Assumptions			
Surface/Highwall Coal Production Shuttered	2037	2017	2037
Underground Coal Production Shuttered	2037	2037	2022
Final Reclamation Earthwork Complete	2046	2043	2047
Monitoring Complete	2056	2053	2056

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UE 374/PacifiCorp
March 31, 2020
Sierra Club Data Request 1.8

(c) PacifiCorp objects to this data request on the grounds that it is unduly burdensome for it to provide the requested documents given that the company is informed and believes that the information sought in the data request may already be in the possession of Sierra Club due to their participation in the out of state proceeding. If Sierra Club seeks to introduce confidential material from an out of state proceeding in this case, PacifiCorp urges Sierra Club to meet and confer with it to discuss the intended use of such documents. PacifiCorp expressly reserves all its rights to object to the introduction of such confidential material from out of state proceedings on all appropriate grounds.

(d) PacifiCorp objects to this data request on the grounds that it is unduly burdensome for it to provide the requested documents given that the company is informed and believes that the information sought in the data request may already be in the possession of Sierra Club due to their participation in the out of state proceeding.

(e) PacifiCorp objects to this data request on the grounds that it is unduly burdensome for it to provide the requested documents given that the company is informed and believes that the information sought in the data request may already be in the possession of Sierra Club due to their participation in the out of state proceeding. If Sierra Club seeks to introduce confidential material from an out of state proceeding in this case, PacifiCorp urges Sierra Club to meet and confer with it to discuss the intended use of such documents. PacifiCorp expressly reserves all its rights to object to the introduction of such confidential material from out of state proceedings on all appropriate grounds.

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UE 374/PacifiCorp
April 1, 2020
Sierra Club Data Request 2.4

Sierra Club Data Request 2.4

Refer to the Direct Testimony of Chad Teply, page 49 at 12 through page 50 at 2. "On January 6, 2011, the Colorado Public Utilities Commission approved the installation of SCR systems on Hayden Units 1-2, finding that PSCo had demonstrated that the installation of the project was in the best interest of customers."

(a) Confirm or deny: PacifiCorp was not a party to Colorado Public Utility Commission ("Colorado PUC") docket 11A-917E. If denied, please provide clarification.

(b) Confirm or deny: the Colorado PUC's decision with respect to the SCR systems on Hayden Units 1-2 binds the Oregon Commission.

(c) Identify any analyses, assessments, presentations, memoranda, communications or the like provided by PSCo to PacifiCorp regarding its assessment that the installation of SCR at Hayden Units 1-2 was in the best interests of customers.

(d) Provide any analyses, assessments, presentations, memoranda, communications or the like provided by PSCo to PacifiCorp regarding its assessment that the installation of SCR at Hayden Units 1-2 were in the best interests of customers.

(e) Identify any independent (i.e. non-PSCo) analyses conducted by, on behalf of, or provided to PacifiCorp regarding the economic cost or benefit of installing the SCR systems at Hayden 1-2.

(f) Provide any independent (i.e. non-PSCo) analyses conducted by, on behalf of, or provided to PacifiCorp regarding the economic cost or benefit of installing the SCR systems at Hayden 1-2.

Response to Sierra Club Data Request 2.4

(a) Confirmed, PacifiCorp was not a party to the Public Service Company of Colorado's (PSCo) certificate of public convenience and necessity (CPCN) proceedings, Docket 11A-917E.

(b) PacifiCorp objects to subpart (b) of this data request because it seeks legal analysis, opinions, and/or conclusions.

(c) PSCo, as the plant operator, provided to PacifiCorp Hayden Unit 1 and Hayden Unit 2 selective catalytic reduction (SCR) project information for

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review in accordance with the pertinent joint ownership agreement and practices.

(d) Please refer to Confidential Attachment Sierra Club 2.4 for Hayden Unit 1 and Hayden Unit 2 SCR project information received from PSCo and PacifiCorp's assessment of the project.

(e) PacifiCorp independently assessed and analyzed its options under the participation agreement for the Hayden Unit 1 and Hayden Unit 2 SCR system projects. The analysis contains commercially sensitive and highly confidential information. The analysis ultimately had no bearing on the Company's Hayden Unit 1 and Hayden Unit 2 SCR systems installation assessment, with the equipment being installed to comply with the Colorado Clean Air-Clean Jobs Act under the purview of the Colorado Public Utilities Commission.

(f) As stated above, the analysis is considered highly confidential and commercially sensitive. The Company requests special handling. Please contact Matt McVee at (503) 813-5585 to make arrangements for review.

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.

Docket No. UE 374
Exhibit Sierra Club/103
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 103

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Jeremy Fisher

Confidential Direct Testimony of Rick Link

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/104
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 104

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Redacted Rebuttal Testimony of Rick Link

REDACTED
Docket No. 20000-418-EA-12
Witness: Rick T. Link

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Rick T. Link

March 2013

Q. Are you the same Rick T. Link that submitted direct testimony in this proceeding?

A. Yes.

Introduction and Summary

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Mr. Randall J. Falkenberg on behalf of the Wyoming Industrial Energy Consumers (WIEC) and Dr. Jeremy Fisher on behalf of Sierra Club. I further explain in my testimony corrections and updates to the analysis used by the Company to support its application for a certificate of public convenience and necessity (CPCN) related to the selective catalytic reduction (SCR) investments planned for Jim Bridger Units 3 and 4 that are responsive to the concerns raised by the parties identified above.

Q. Please summarize your rebuttal testimony in this proceeding.

A. My rebuttal testimony specifically addresses concerns raised by the parties in this proceeding that are associated with the financial analysis supporting SCR investments at Jim Bridger Units 3 and 4. Specifically, I am providing testimony on the following:

- Updated base case analysis results that reflect corrections to the Company's original analysis and that incorporate assumption updates responsive to the parties showing a Present Value Revenue Requirement Differential (PVRR(d)) of [redacted] favorable to the SCR investments required at Jim Bridger Units 3 and 4.

- Updated and expanded natural gas and carbon dioxide (CO_2) price scenario analysis results showing a range of PVRR(d) outcomes that support the SCR investments in six of the nine scenarios studied.
- Updates to base case natural gas price and CO_2 price assumptions that are aligned with the Company's September 2012 official forward price curve (OFPC).
- Updates to coal cost assumptions.
- Updates to load forecast assumptions.
- Description of a new sensitivity showing that alternative Energy Gateway transmission assumptions and Wyoming wind resource assumptions improve the PVRR(d) results in favor of the SCR investments.
- Description of a new sensitivity showing that the SCR investments are favorable to an early retirement and resource replacement alternative.

Corrections

Q. Did you make any corrections to the PVRR(d) results that were summarized in your direct testimony?

A. Yes. The PVRR(d) is derived by taking the difference in present value revenue requirement (PVRR) between two System Optimizer (SO) Model simulations – one simulation in which the SCR equipment required for continued coal-fueled operations is installed at Jim Bridger Units 3 and 4 and another simulation in which the SCR investments are not made. In the simulation where the SCR installations do not occur, the SO Model chooses to convert Jim Bridger Units 3 and 4 to natural gas as the next best, albeit higher cost, alternative.

In the case where Jim Bridger Units 3 and 4 are converted to natural gas, mine capital costs that were assigned pro-rata to these two units were not reported in the PVRR(d) results summarized in my direct testimony, and therefore, mine capital costs were understated. This increases costs in the case where the SCR investments are not made at Jim Bridger Units 3 and 4 and, all else being equal, improves the PVRR(d) favorable to the SCR investment by [redacted]. Also in the case where Jim Bridger Units 3 and 4 are converted to natural gas, the PVRR(d) results summarized in my direct testimony included one year of cost for the SCR equipment on Jim Bridger Unit 4. This overstated costs in the case where the SCR investments are not made, and all else being equal, reduces the PVRR(d) favorable to the SCR investment by [redacted]. These two corrections result in increasing the base case PVRR(d) in my direct testimony from [redacted] to [redacted] favorable to the SCRs, prior to other assumption updates which I will discuss in the next section of my rebuttal testimony.

Q. Are there any other corrections made to the SO Model analysis that you summarized in direct testimony?

A. Yes. The capacity for the Wyodak coal-fired unit located in eastern Wyoming was modeled as a 324 megawatt (MW) generation resource instead of a 268 MW generation resource. In the Company's updated analysis, which I describe in more detail below, SO Model simulations were updated with the correct capacity for the Wyodak coal unit.

Updated Base Case Assumptions

Q. Did the Company make any updates to its assumptions used in the SO Model for its analysis of the Jim Bridger Units 3 and 4 SCR equipment?

A. Yes. It is important that the Company update its analysis with new information as it becomes available to ensure that the SCR investments being evaluated in this case are in the best interest of customers. To this end, the following assumptions have been updated in the base case SO Model analysis:

- Natural gas and CO_2 price assumptions;
- Coal cash cost, mine capital and mine reclamation assumptions; and
- Load forecast assumptions.

In addition, in the current proceeding, the Company made the adjustment proposed by WIEC to set the Gadsby peaking units and the Currant Creek combined cycle plant as must-run units.

Q. How have forward natural gas prices and long-term natural gas price forecasts changed since the Company filed its CPCN?

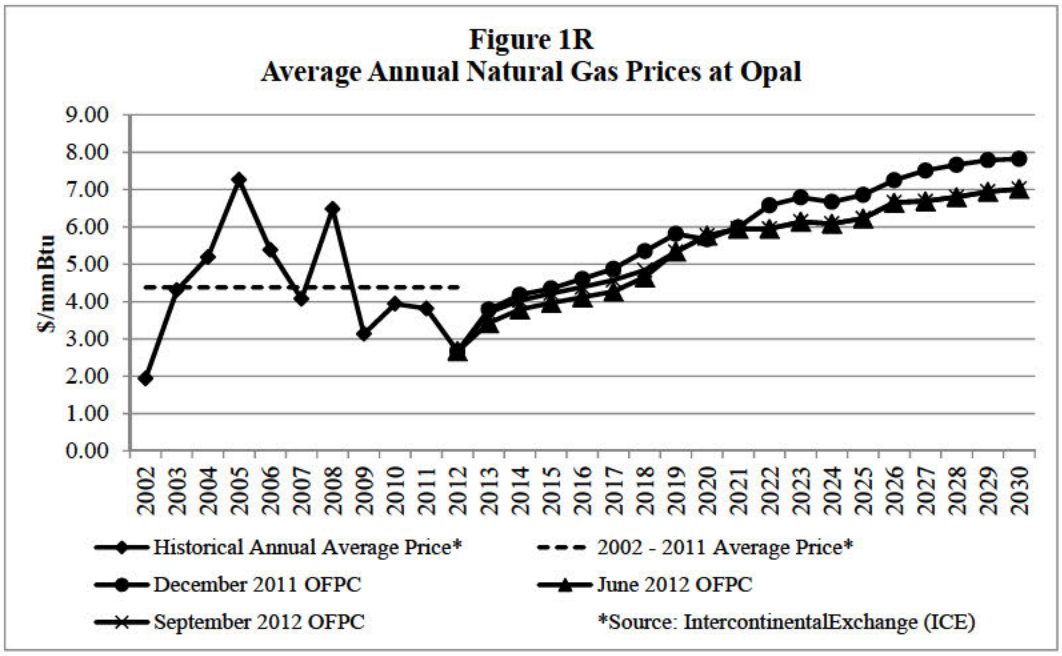
A. The Company relied upon its December 2011 OFPC in the base case analysis of the Jim Bridger Units 3 and 4 SCR investments and estimated the PVRR(d) impact of using its June 2012 OFPC. Average annual natural gas prices at the Opal market hub over the forward period 2016 through 2030 were down approximately nine percent in the June 2012 OFPC as compared to the December 2011 OFPC. The updated base case analysis discussed herein was performed using the September 2012 OFPC. Opal natural gas prices from the September OFPC over the forward period 2020 and beyond are identical to those in the June

2012 OFPC and are four percent higher than average annual prices from June 2012 OFPC over the forward period 2016 through 2019.

Q. Describe how the forward trend in natural gas prices compares to historical prices at the Opal market hub.

A. Figure 1R below shows historical average annual natural gas prices and forward natural gas prices from the December 2011 OFPC, the June 2012 OFPC, and the updated base case September 2012 OFPC at the Opal market hub. Over the 11-year period 2002 through 2012, prices at Opal averaged $4.38 per mmBtu. The highest annual average price over this period is $7.26 per mmBtu, which occurred in 2005 when hurricanes Katrina, Rita, and Wilma caused significant production losses in the Gulf of Mexico region. Average annual prices were $6.48 per mmBtu in 2008, which coincided with the general rush to commodities in advance of the collapse of the housing bubble later that year.

In the September 2012 OFPC, Opal market prices over the period 2016 through 2020 average $4.98 per mmBtu. Prices over the period 2021 through 2030 average $6.45 per mmBtu, which is 29 percent higher than prices in the 2016 to 2020 timeframe and 47 percent higher than average historical prices over the period 2002 through 2012. While forward prices from the September 2012 OFPC have fallen in relation to forward prices from the December 2011 OFPC, average annual prices over the mid- to long-term are expected to rise above near-term forwards and historical price levels.



Q. Has the Company updated its base case assumptions for CO_2 prices?

A. Yes. The September 2012 OFPC reflects an assumed CO_2 policy that will be implemented in 10 years, and as such, CO_2 prices are assumed to begin in 2022, one year later than assumed in the Company's original base case analysis. The initial price level for CO_2 emissions has not changed, with prices starting at $16 per ton and escalating at three percent plus inflation thereafter. The one-year delay in the assumed start date for CO_2 prices remains consistent with assumptions from third party forecasts, with a one-year delay observed in one third party projection, and is consistent with the lack of legislative activity on developing federal greenhouse gas policies in 2012.

Q. Please describe how the Company's coal cost assumptions have been updated for the new base case analysis.

A. Base case coal cost assumptions have been updated for both the four-unit operation and the two-unit operation fueling plans. As I discussed in my direct

testimony, the two-unit operation fueling plan takes into consideration how the plant fueling requirements are affected if Jim Bridger Units 3 and 4 stop operating as coal-fueled generation assets. The updated coal cost assumptions are informed by more current mine plans and reclamation plans, which are described in more detail in the rebuttal testimony of Company witness Ms. Cindy A. Crane.

Updated cash coal cost assumptions, representing all non-capital related costs to fuel the Jim Bridger plant, are included alongside the cash coal costs assumed in the original base case in Confidential Exhibit RMP___(RTL-1R). On average, over the period 2013 through 2030, cash coal costs for the four-unit operation fueling plan have [redacted] per mmBtu (approximately 6.6 percent) as compared to the original base case assumptions. The increase in cash coal costs for the four-unit operation fueling plan reflects updated third party coal prices and transportation costs for Black Butte coal as well as updated cash operating costs for Bridger Coal Company. The increase in cost is primarily attributable to an increase in final reclamation trust contributions and the cost impact of reduced production from the Bridger surface mine in the 2015-2017 timeframe.

Over the period 2013 through 2030, average annual cash coal costs for the two-unit operation fueling plan have [redacted] per mmBtu (approximately 4.3 percent) relative to the original base case assumptions. The decrease in cash coal costs for the two-unit operation fueling plan, which also reflects updated third party coal prices and transportation costs for Black Butte coal and Bridger Coal Company cash operating costs, is principally associated

with reduced underground mine operating costs starting in 2017. Company witness Ms. Crane describes in more detail updated coal cost assumptions.

Q. Did the Company update mine capital cost assumptions given the availability of a more current mine plan?

A. Yes. As informed by an updated mine plan, the mine capital cost assumptions for Bridger Coal Company's surface and underground mining operations have been updated for both a four-unit operation and the two-unit operation fueling plan at the Jim Bridger plant. Updated mine capital cost assumptions are included alongside the mine capital costs assumed in the original base case in Confidential Exhibit RMP___(RTL-2R).

Over the period 2013 through 2030, average annual mine capital cost assumptions for a four-unit operation fueling plan are higher by about [redacted]. Over the same period, average annual mine capital cost assumptions for a two-unit operation fueling plan at the Jim Bridger plant are higher by approximately [redacted]. Relative to the original base case assumptions, mine capital cost increases are most significant from 2021 through 2026, where annual average mine capital costs are higher by [redacted] in the four-unit operation fueling plan and higher by [redacted] in the two-unit operation fueling plan. Beyond 2026, average annual updated mine capital cost assumptions are lower by [redacted] and [redacted] in the four-unit and two-unit operation fueling plans, respectively.

Q. Please summarize the key drivers behind the updated mine capital cost assumptions.

A. As described in the testimony of Company witness Ms. Crane, the key drivers behind the updated mine capital costs in the cases pertain to additional surface and underground mine reserve acquisition costs as well as additional mine extension costs and longwall system rebuild/replacement costs.

Q. Did the Company update mine reclamation cost assumptions in its updated base case analysis?

A. Yes. Mine reclamation costs are included in the updated cash coal cost assumptions I described above. Cash coal costs drive the fuel cost for Jim Bridger in the SO Model analysis, which has a study horizon extending out through 2030.

Q. Was the Company criticized for its treatment of mine reclamation costs beyond the 2030 study period used in the SO Model analysis?

A. Yes. WIEC noted that reclamation costs in the continued coal operation case beyond the 2030 study horizon were not factored into the PVRR(d) results originally filed by the Company.

Q. How do you respond?

A. In the updated base case analysis, the Company has factored into its PVRR(d) results contributions to the mine reclamation trust that are not accounted for in the cash coal costs inputs used in the SO Model. This includes contributions to the mine reclamation trust over the period 2031 through 2037 for both the four-unit and two-unit operation fueling plans at the Jim Bridger plant. Over this timeframe, annual contributions to the mine capital trust total [redacted] under a

four-unit operation plan and [redacted] under a two-unit operation plan. Assumptions for contributions to the mine reclamation trust are summarized in Confidential Exhibit RMP___(RTL-3R).

Q. In its review of base case assumptions, did the Company include the most current load forecast in its updated SO Model analysis?

A. Yes. The Company included in its updated base case analysis its most current load forecast consistent with the load forecast used in the "Needs Assessment" filed with the Utah Public Service Commission through the All Source Request for Proposals for a 2016 Resource (Utah Docket No. 11-035-73). This is the same load forecast that is being used in the Company's 2013 IRP as referenced by WIEC.[1]

Q. Please describe how the Company's load forecast has changed.

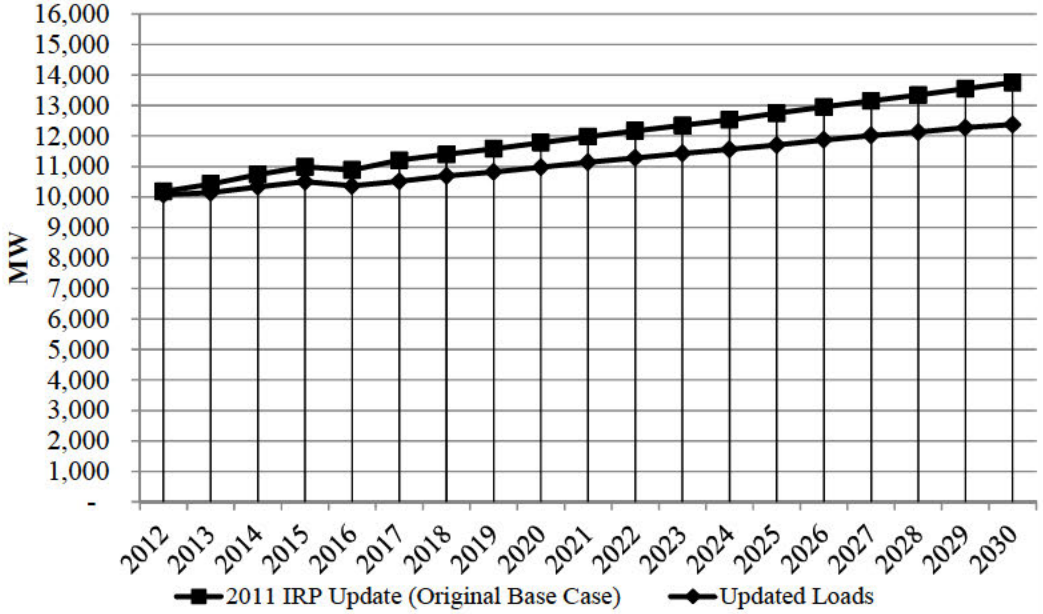
A. The Company's current load forecast is lower than the load forecast used in the original base case analysis, which was consistent with the load forecast used in the Company's 2011 IRP Update. The lower load forecast is driven by reduced industrial sector loads in Utah and Wyoming that reflect load request cancellations and postponements necessitated by prolonged recessionary impacts and permitting issues. The most current load forecast also incorporates projections of increased industrial self-generation driven largely by lower wholesale gas and electricity prices. Finally, the Company's new industrial load forecast uses a regression analysis in place of a probability assessment of customer-provided forecasts.

Figure 2R below compares the updated coincident peak load forecast to

[1] See Confidential Exhibit RJF-2 of WIEC witness Mr. Randall J. Falkenberg at page 8 line 13.

the original coincident peak load forecast used in the SO Model analysis. As compared to the original load forecast, the annual coincident peak load projection is on average reduced by 663 megawatts over the period 2015 through 2020, reduced by 934 megawatts over the period 2021 through 2025, and reduced by 1,215 megawatts over the period 2026 through 2030.

Figure 2R
Coincident Peak Load Forecast



Q. Were any parties to this proceeding critical of how certain assets were dispatched in the Company's SO Model analysis?

A. Yes. WIEC was critical of the SO Model's dispatch for the Gadsby and Currant Creek combined cycle resources and suggested that these assets should be modeled with must run assumptions as implemented in GRID studies.

Q. Did you make any changes to the SO Model in response to these concerns?

A. Yes. The Company enforced must run settings on the Gadsby peaking units and the Currant Creek combined cycle plant to be consistent with the must run

settings applied to these assets in GRID studies.

Q. Did the Company update its forced outage assumptions applied to Jim Bridger Units 3 and 4?

A. No. WIEC explains how the Company's forced outage rate assumptions for Jim Bridger Units 3 and 4 are lower than forced outage rate assumptions used in GRID for net power cost filings. The assumptions used in the SO Model analysis do not explicitly separate forced outage rates from planned outage rate assumptions. Rather, the SO Model assumptions are configured to represent projected availability, taking into consideration both planned and unplanned outage events on a forecast basis. The Company believes that forecasted unit availability data are appropriate for use in analyzing the forecasted PVRR(d) benefits or costs associated with SCR equipment required on Jim Bridger Units 3 and 4.

Q. How are forced outages modeled in GRID for regulatory net power cost filings?

A. The Company uses the average of the most recent four-year historical outage data for each unit. This outage amount is used in GRID to de-rate the maximum capacity of each unit by a fixed percentage.

Q. Why does the Company use a four-year historical average to model forced outages for net power cost studies?

A. There are two primary reasons. First, use of a rolling four-year average reflects the current operation of each unit and smoothes the data to limit the magnitude of changes from year to year. Second, using actual data to determine a normalized

outage rate allows forecast net power costs to reflect the availability that was historically experienced by the Company.

Q. How are planned outages modeled in GRID for regulatory net power cost filings?

A. Planned outages are based on the same four-year average as forced outages. They are placed throughout the forecast period to best match the timing of the historical outages and are modeled by setting the unit that is on planned outage to zero.

Q. Why does the Company use a four-year historical average to model planned outages for purposes of net power cost filings?

A. For the same reasons stated above for forced outages.

Q. Please explain why use of forecasted unit availability (planned and unplanned outages) is applied in the SO Model analysis supporting this case.

A. Unlike a typical net power cost study, which often covers a one-year normalized forward test period, the SO Model simulates PacifiCorp's system over a study horizon extending through 2030. Use of forecasted availability rates allows the SO Model to factor into its optimization routine the anticipated timing of major maintenance activities, which are aligned with the installation of environmental equipment such as the SCR equipment required on Jim Bridger Units 3 and 4. Forecasted availability rates also allow the SO Model to reflect expected year-to-year availability changes identified by plant staff in anticipation of operational changes or regulatory requirements identified during the Company's planning processes. The availability forecasts generated by plant staff are informed by prior operating history and experience, recognized industry best practices, and original

equipment manufacturer recommendations, where applicable.

Q. Did the Company update its assumptions for the cost of the SCR equipment in its updated base case analysis?

A. No. The cost of the SCR equipment assumed in the Company's updated analysis is identical to the cost assumptions used in the original analysis, which are based on engineering, procurement, and construction (EPC) bids for the SCR equipment required at Jim Bridger Units 3 and 4.

Q. Did any of the parties in this case raise concerns with the SCR cost assumption used in the Company's analysis?

A. Yes. In the original analysis used to support the CPCN, the Company began analyzing the Jim Bridger Units 3 and 4 SCR investments using preliminary cost estimates as inputs to the SO Model. These cost assumptions were improved after the SO Model simulations were completed based upon refined cost data from EPC bids for the Jim Bridger SCR equipment. The Company factored the updated cost information into the original SO Model results with a manual adjustment performed outside of the model. Applying the update as an adjustment outside of the SO Model as compared to applying the update to the SO Model inputs and rerunning the SO Model would yield the same PVRR(d) results. This is because the capital cost for the SCRs is a fixed cost that does not affect how the system is dispatched, and therefore, the costs have no impact on other variables that affect the SO Model solution (i.e. system costs such as fuel costs). WIEC identified this assumption update as a "problematic assumption" and testified that the range of

potential impacts ranges between [redacted].[2]

Q. How do you respond?

A. The Company's SCR cost assumptions are not in any way "problematic". The Company applied the manual adjustment in its original analysis simply to ensure that the more current and more refined SCR costs would be reflected in the PVRR(d) results supporting the CPCN.

Q. Did the Company apply manual adjustments to the updated SO Model results?

A. No. In the original analysis supporting the CPCN, the Company performed manual adjustments to the SO Model results to reflect assumption updates made after the original SO Model simulations were completed to ensure PVRR(d) results would reflect current cost information. In updating its analysis, the Company has incorporated into the SO Model all updated assumptions, which alleviates the need for manual adjustments.[3]

Q. Does WIEC raise any concerns with the assumed recovery of SCR costs as applied in the Company's analysis?

A. Yes. WIEC testifies that the Company's analysis does not accurately capture the timing in which SCR costs would be included in rate base and characterizes this as an "error" in the analysis with an estimated PVRR(d) impact of [redacted] favorable to the Jim Bridger Units 3 and 4 SCR investments.[4] WIEC claims that the Company's analysis assumes the SCR systems are included in rate base in

[2] See Confidential Table EX-2-1 in the direct testimony of WIEC witness Mr. Randall J. Falkenberg.
[3] Note, the PVRR(d) impact of mine reclamation funds over the period 2031 through 2037, which was requested by several parties, are calculated outside of the SO Model because this period extends beyond the SO Model study horizon.
[4] See Confidential Exhibit RJF-2 of WIEC witness Mr. Randall J. Falkenberg at page 13 line 1.

advance of when the equipment would be operational and are not aligned with the timing of an assumed future Wyoming general rate case.

Q. How is WIEC's argument flawed?

A. WIEC hypothetically assumes that the Company will file its next Wyoming general rate case on March 1, 2014. The Company has made no determination at this time that it will file a Wyoming general rate case on March 1, 2014. This date only represents the earliest date which the Company could file a rate case as a result of a prior rate case stipulation. WIEC fails to note that any extension of the next Wyoming general rate case filing beyond March 1, 2014 would include more of the SCR investments to the Wyoming case when it is eventually filed.

More importantly, WIEC's claim is based on an assumption that all of the Company's general rate cases in its six-state service territory follow the same commitments that were made in Wyoming, which is inaccurate. The Company can have general rate cases across its six-state service territory at varying time intervals, and each case would have different base periods, different test periods, and different rate base treatments. In this way, WIEC's hypothetical analysis is grossly oversimplified and misleading.

Q. Are there any other inaccuracies in WIEC's rate recovery analysis?

A. Yes. WIEC fails to apply the same principles consistently among an SCR investment scenario and to a potential gas conversion scenario – completely ignoring differences in all capital and net power cost elements between these two potential alternatives over time.

Q. Did the Company update its treatment of revenue requirement for SCR costs in its updated analysis?

A. No. The system wide modeling of major investments by the Company such as the SCRs required at Jim Bridger Units 3 and 4 is based on the assumption that there is no regulatory lag. In other words, the individual commitments made in rate cases regarding the timing of rate cases, test period dates, forecast versus average rate base and other regulatory details are not taken into account for system modeling purposes. Such an approach is the only practical means to study individual investment decisions considering that the alternative would require an assessment of how every individual investment decision being contemplated by the Company at any point in time might affect general rate case filings over time across the Company's six-state service territory.

Updated Base Case Results

Q. How has the base case PVRR(d) result changed with the updated assumptions that were applied in the SO Model?

A. As originally described in my direct testimony, the base case developed off of the December 2011 OFPC produced a PVRR(d) that was [redacted] favorable to the SCR investment required at Jim Bridger Units 3 and 4. The updated base case that has been developed off of the September 2012 OFPC, and that incorporates corrections and assumption updates as I described above, produces a PVRR(d) that is [redacted] favorable to the SCR investment required at Jim Bridger Units 3 and 4.

Q. With the updated assumptions, did the SO Model continue to select gas conversion as the next best, albeit higher cost, alternative to the SCR investments at Jim Bridger Units 3 and 4?

A. Yes.

Q. Please explain how the updated assumptions contribute to the change in base case PVRR(d) results.

A. Confidential Table 1R below summarizes how the corrections and assumption updates applied in the base case analysis affect the base case PVRR(d) results as compared to what was summarized in my direct testimony. The table shows that after accounting for the correction to mine capital and SCR costs reported in the original two-unit operation case, updated natural gas price assumptions, and updated coal cost assumptions are most influential to the change in PVRR(d) results.

Confidential Table 1R
Change in Base Case PVRR(d) (Benefit)/Cost of SCRs
$ Million

Description of Update/Correction	Incremental Change in PVRR(d)	Accumulated Change in PVRR(d)
Original Base Case in CPCN (December 2011 OFPC)	n/a	[redacted]
Correction to Mine Capital/SCR Costs	[redacted]	[redacted]
Correction to Wyodak capacity, application of Gadsby & Currant Creek Must Run	[redacted]	[redacted]
Update to September 2012 OFPC	[redacted]	[redacted]
Updated Coal Cost & Bridger Coal Mine Capital	[redacted]	[redacted]
Updated Load Forecast	[redacted]	[redacted]
Mine Reclamation Fund Contributions beyond 2030	[redacted]	[redacted]

Q. Please explain why the updated forward price curve assumptions make the PVRR(d) results less favorable to the SCR investments.

A. Nominal levelized natural gas prices at the Opal market hub over the period 2016 through 2030 in the December 2011 OFPC were $6.18 per mmBtu. Nominal levelized natural gas prices at the Opal market hub from the September 2012 OFPC over the same term are $5.72 per mmBtu, which is approximately eight percent below levelized prices from December 2011. The assumed price for natural gas directly affects the cost for a gas-fueled replacement alternative, which is directionally favorable to gas conversion as an alternative to the SCR investments. Natural gas prices are also a key factor in setting wholesale power prices. As gas prices fall, the market value of energy is reduced. In this way, gas prices disproportionately affect the value of energy net of operating costs from Jim Bridger Units 3 and 4 when operating as coal-fueled resources versus the value of reduced energy output net of operating costs from a gas conversion alternative.

Q. Did you identify in your direct testimony how falling natural gas prices might affect the PVRR(d) of the SCR investments?

A. Yes. Based upon the relationship between natural gas price assumptions and PVRR(d) results described in my direct testimony, I described that the June 2012 OFPC would erode the base case PVRR(d) results favorable to the Jim Bridger Units 3 and 4 SCR equipment by approximately [redacted]. Considering that natural gas prices from the September 2012 OFPC are slightly higher than the natural gas prices from the June 2012 OFPC through 2018 and that prices

between the two price curves are aligned from 2019 and beyond, the [redacted] incremental impact of updating forward price curve assumptions is consistent with the estimate in my direct testimony.[5]

Q. Please explain why the updated coal costs make the PVRR(d) results less favorable to the SCR investments.

A. As I discussed earlier in my testimony, cash coal costs were updated consistent with more current mine plans and reclamation plans for Bridger Coal Company. The updated average annual cash coal cost assumptions for the continued coal operation case have increased by approximately 6.6 percent, and the average annual cash coal costs for Jim Bridger Units 1 and 2 in the Jim Bridger Units 3 and 4 gas conversion case have decreased by approximately 4.3 percent. Higher cash coal costs in the continued coal operation case and lower cash coal costs in the gas conversion case reduces the benefits of the SCR investments. Nonetheless, while the updated PVRR(d) results are directionally less favorable to the SCR investments, the updated base case analysis continues to support the SCR investments required at Jim Bridger Units 3 and 4.

Q. WIEC estimates that an updated load forecast would reduce the PVRR(d) results in favor of the Jim Bridger SCRs by [redacted]. Have you reviewed WIEC's study?

A. Yes. WIEC's analysis is based on the Company's GRID study that was used in an avoided cost filing in Utah. To arrive at the estimated PVRR(d) impact, WIEC calculated the PVRR(d) from a pair of GRID studies that were based upon the

[5] Nominal levelized prices at the Opal market hub over the period 2016 through 2030 were $5.65 per mmBtu in the June 2012 OFPC, which is just $0.07 per mmBtu lower than levelized prices from the September 2012 OFPC.

avoided cost filing. In one study, WIEC assumed Jim Bridger Units 3 and 4 continued operating as coal and in the other study, WIEC replaced Jim Bridger Units 3 and 4 with gas conversion alternatives. WIEC then calculated the difference between this PVRR(d) result with the PVRR(d) result from the GRID benchmarking study that I summarized in my direct testimony to arrive at their [redacted] estimate.

Q. How did WIEC arrive at the upper range of their estimate?

A. WIEC testifies that the impact could easily be 50 percent greater and simply multiplies [redacted] by a factor of 1.5 to arrive at the high estimate of [redacted].

Q. Does WIEC describe or otherwise indicate how they arrived at the 50 percent increase used to develop the high range of their estimate?

A. No. The 50 percent increase used in WIEC's analysis is entirely unsupported.

Q. Do you agree with WIEC's estimate?

A. No. WIEC represents that an updated load forecast, and subsequent change in the resource expansion plan, would erode the PVRR(d) benefits of the SCR equipment by [redacted] to [redacted]. Not only is the high end of this estimate unsupported, the low end of the range has been misinterpreted by WIEC and is misleading.

Q. Please explain.

A. The Company's avoided cost filing includes not only an updated load forecast and corresponding resource expansion plan, but it also includes September 2012 OFPC inputs for electricity and natural gas price assumptions. By comparing the

PVRR(d) between the two pairs of GRID studies, WIEC's estimate includes the impact of updating the forward price curve. As I discussed above and as I estimated in my direct testimony, the updated forward price curve assumptions are a significant driver to the change in the PVRR(d) results. WIEC presents their estimated load forecast impact as being driven by an updated load forecast and subsequent resource expansion plan. This is misleading considering that WIEC's estimate also includes the effect of updated forward price curve assumptions.

Q. Are there any other problems with WIEC's estimate of the PVRR(d) impact associated with an updated load forecast?

A. Yes. WIEC did not capture in their analysis how the Company's resource portfolio would be impacted if Jim Bridger Units 3 and 4 were converted to natural gas. The difference in resource portfolios was reflected in the Company's GRID benchmark studies described in my direct testimony. Not only does WIEC's estimate misleadingly include the effect of an updated forward price curve, it fails to capture how the Company's resource expansion plan would be affected if Jim Bridger Units 3 and 4 were converted to natural gas.

Q. Did the Company update its base case analysis using GRID?

A. No. The Company's GRID study that I summarized in my direct testimony was performed in response to parties' concerns raised in the Naughton Unit 3 CPCN proceeding. The Company does not believe that the GRID model is the appropriate tool to analyze clean air investments when alternatives to those investments include gas conversion and early retirement of generating resources. These alternatives would fundamentally influence the timing and type of new

resources in the Company's resource expansion plan, and therefore, impacts to the resource expansion plan are an important component to the analysis of clean air investment alternatives.

Q. Do any of the parties in this proceeding criticize the Company's use of the SO Model as applied in this proceeding?

A. Yes. WIEC argues that the SO Model is appropriate in the context of an IRP, implying that the SO Model is not well suited for the type of clean air investment analysis that the Company has performed in this proceeding. WIEC identifies that the primary advantages of the SO Model is that it enables processing of a large number of scenarios and resource options and that it can be used to develop a resource expansion plan for a given set of economic conditions. However, WIEC dismisses these benefits as being unimportant claiming that resources in coal and gas conversion simulations were nearly identical and have little practical benefit.

Q. How do you respond?

A. The Company's SO Model simulations show changes to the resource portfolio across the entire simulation period. These changes can include the incremental need for front office transactions, changes to demand side management resources, and shifts in the timing and type of new natural gas resources over the study period. Seemingly small changes in the optimal resource expansion plan can add up over the study period, and the magnitude of the change in the resource expansion plan can change among scenarios.

Q. Are there any inconsistencies in WIEC's direct testimony as it pertains to the importance of an optimized expansion plan?

A. Yes. WIEC claims the Company's analysis of the Jim Bridger Units 3 and 4 SCR investments failed to examine its coal fleet as a whole to determine whether other units might be candidates for natural gas conversion. WIEC witness Mr. Falkenberg makes mention of a separate analysis that he has performed in the concurrent Utah proceeding using the Cumulus model to conclude that the fate of clean air investments that might be required at other coal units could have a significant impact on the PVRR(d) results of the Jim Bridger SCR investments. WIEC's view that changes to the resource expansion plan are not important to the Jim Bridger SCR analysis is in conflict with Mr. Falkenberg's claim that clean air investment decisions on other coal units could significantly affect the Jim Bridger SCR analysis.

Q. Does the Company's base case and scenario analyses allow for early retirement and gas conversion alternatives for other coal units beyond Jim Bridger Units 3 and 4.

A. Yes. The Company's original analysis and updated analysis described herein has allowed for early retirement and natural gas conversion as potential alternatives to major clean air investments at other coal units in the fleet. The effects of these outcomes are included in the PVRR(d) results performed by the Company in support of this CPCN proceeding, and it is precisely this type of capability that supports the use of the SO Model. GRID is not capable of producing resource expansion plans, nor is it capable of determining whether clean air investments at

other coal units might lead to additional gas conversion or early retirement outcomes, as evidenced by WIEC's reference to use of the Cumulus model to draw their conclusions.

Q. How do other parties in this proceeding view the use of the SO Model as used by the Company to analyze the Jim Bridger Units 3 and 4 SCR investments?

A. Wyoming Office of Consumer Advocate (OCA) witness Mr. Bryce J. Freeman discusses the benefits of the SO Model as compared to GRID and concludes that the GRID model is substantially less suitable for scenario analysis as compared to the SO Model. Mr. Freeman also accurately notes that GRID does not endogenously select expansion resources, and concludes that a process to evaluate the effects of changes to the resource portfolio using GRID would be very cumbersome in comparison to the SO Model. Sierra Club, while in disagreement with certain assumptions used by the Company, approves of the Company's modeling framework as used in this proceeding.

Updated Natural Gas and CO_2 Price Scenario Assumptions

Q. Has the Company updated its natural gas price and CO_2 price scenario analysis?

A. Yes. Concurrent with the update to base case forward price curve assumptions as discussed above, the Company reviewed the range of updated natural gas and CO_2 price forecasts from third parties to establish updated low and high projections.

Q. Did you use the same approach to establish low and high projections for your updated analysis?

A. Yes. The fundamental approach of reviewing the range of third party price

forecasts in relation to the base case price projections is identical to the approach used to develop natural gas and CO_2 price scenarios in the Company's original analysis. We simply included in our review more recent third party forecast data.

Q. Did the Company expand the number of natural gas and CO_2 price scenarios used to evaluate the Jim Bridger Units 3 and 4 SCR investments?

A. Yes. The Company's natural gas price and CO_2 price scenario analysis has been expanded to include additional scenarios that pair low natural gas price with low CO_2 price assumptions and that pair high natural gas price with high CO_2 price assumptions. Table 2R below summarizes the directional changes to base case natural gas and CO_2 price assumptions among the nine different scenarios included in the updated analysis. Confidential Exhibit RMP___(RTL-4R) to my rebuttal testimony shows how the low and high price assumptions used in the Company's updated scenarios compare to current third party forecasts.

Table 2R
Natural Gas and CO_2 Price Scenarios

Description	Natural Gas Prices	CO_2 Prices
Base Case	September 2012 OFPC	$16/ton in 2022 rising to $23/ton by 2030
Low Gas, Base CO_2	Low	$16/ton in 2022 rising to $23/ton by 2030
High Gas, Base CO_2	High	$16/ton in 2022 rising to $23/ton by 2030
Base Gas, $0 CO_2	Base Case Adjusted for Price Response	No CO_2 Costs
Base Gas, High CO_2	Base Case Adjusted for Price Response	$14/ton in 2020 rising to $65/ton by 2030
Low Gas, High CO_2	Low Case Adjusted for Price Response	$14/ton in 2020 rising to $65/ton by 2030
High Gas, $0 CO_2	High Case Adjusted for Price Response	No CO_2 Costs
Low Gas, $0 CO_2 (New Scenario)	Low Case Adjusted for Price Response	No CO_2 Costs
High Gas, High CO_2 (New Scenario)	High Case Adjusted for Price Response	$14/ton in 2020 rising to $65/ton by 2030

Q. How do your updated CO_2 price scenarios compare to those used in your original analysis?

A. As noted earlier, base CO_2 price assumptions begin in 2022 as opposed to 2021. For the low case, the Company continues to assume that there is no CO_2 price imputed on emissions. The high case assumes there is a tax on CO_2 emissions beginning 2020, two years later than in the original high case assumptions and two years earlier than in the updated base case assumptions. Relative to the original high case assumptions, CO_2 prices in the updated high case start at a lower price level, but escalate rapidly through 2025 and reach $65 per ton by 2030. The change in the high case CO_2 prices better aligns with a current high price forecast from [redacted], a reputable third party source.

Q. How do your updated natural gas price scenarios compare to those used in your original analysis?

A. Consistent with the drop in base case natural gas prices, third party forecasters have lowered their long-term natural gas price projections, which supports a drop in the Company's low and high natural gas price assumptions. At base CO_2 price levels, average annual prices in the low natural gas price forecast and the high natural gas price forecast are down by 15 percent and 13 percent, respectively, over the period 2016 through 2030.

Q. Why do you adjust natural gas price assumptions in those scenarios where CO_2 price assumptions vary from the base case?

A. As discussed in my direct testimony, we assume that different levels of CO_2 prices will affect the demand for natural gas in the electric sector of the U.S.

economy and that any change in natural gas demand would be balanced with a change in supply and subsequent movement in the market price for natural gas. In effect, we assume that as the intersection of supply and demand for natural gas changes, the price for natural gas will change accordingly.

Q. Have any of the parties in this case identified concerns with this assumption?

A. Yes. Sierra Club testifies that there is currently no definitive evidence that such a trend would occur and that it is not appropriate to assume natural gas prices will increase in the presence of a CO_2 price.

Q. Does the Company only apply upward adjustments to natural gas prices in response to changes in CO_2 price level?

A. No. The assumed interaction between natural gas prices and CO_2 prices is bi-directional. That is, the Company not only assumes natural gas prices rise in the presence of a CO_2 price (or with increased CO_2 price levels), but also incorporates downward natural gas price pressures when CO_2 prices are removed or lowered.

Q. Is this the first time that the Company has made assumptions regarding the interaction between natural gas and CO_2 prices?

A. No. The Company has assumed a dynamic interaction between natural gas price and CO_2 price assumptions in developing market price scenarios for the 2008 IRP, the 2011 IRP, and in developing market price scenarios in the evaluation of bids submitted into recent all source request for proposals.

Q. Are you aware of other forecasts that account for the interaction between natural gas prices and CO_2 prices?

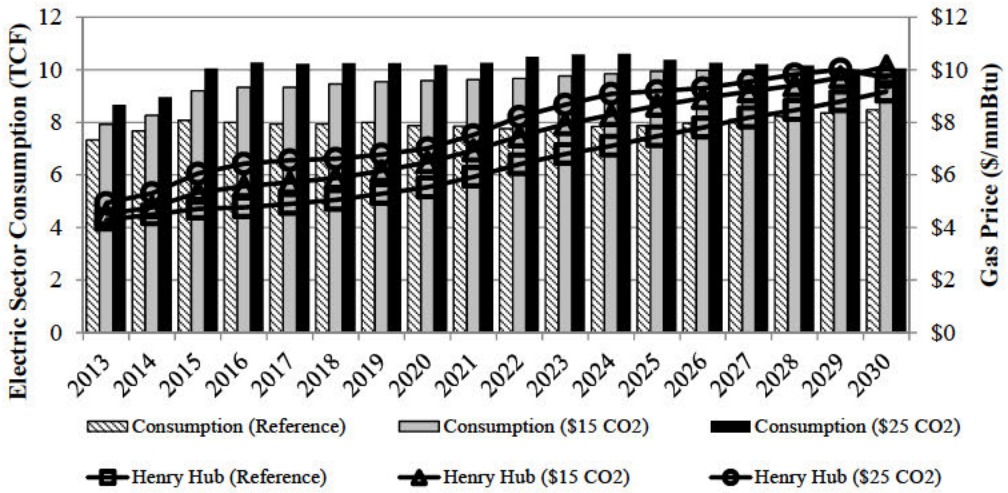
A. Yes. The U.S. Energy Information Administration's (EIA) 2012 Annual Energy

Outlook (AEO) includes a reference case Henry Hub natural gas price forecast and a broad range of forecast scenarios.[6] In one of these scenarios, EIA applies a \$15 CO_2 emissions fee to the U.S. economy beginning 2013. In another scenario, EIA applies a \$25 CO_2 emissions fee.[7] Under the AEO reference case and in the two CO_2 emission fee scenarios, EIA reports natural gas consumption by sector of the U.S. economy, including a line item for the electric sector, and a forecast of Henry Hub natural gas prices.

Figure 3R below shows EIA's annual electric sector natural gas consumption and the accompanying Henry Hub natural gas price forecast for the AEO 2012 reference case and the two CO_2 emission fee scenarios. The left horizontal axis reports electric sector gas consumption in trillion cubic feet (TCF) and the right horizontal axis reports nominal Henry Hub natural gas prices. The figure clearly shows that electric sector natural gas consumption increases from the reference case when a \$15 CO_2 emissions fee is assumed, and increases further when a \$25 CO_2 emissions fee is assumed. Moreover, the figure shows that the presence of a CO_2 emissions fee drives higher natural gas prices consistent with a rise in natural gas consumption, and that the magnitude of the impact increases with a higher CO_2 emissions fee assumption.

[6] The U.S. Energy Information Administration is the statistical and analytical agency within the U.S. Department of Energy.
[7] In each CO_2 scenario, prices are assumed to escalate at five percent per year.

Figure 3R
Annual Energy Outlook 2012: Gas Consumption & Gas Price Changes with Varying CO_2 Price Assumptions

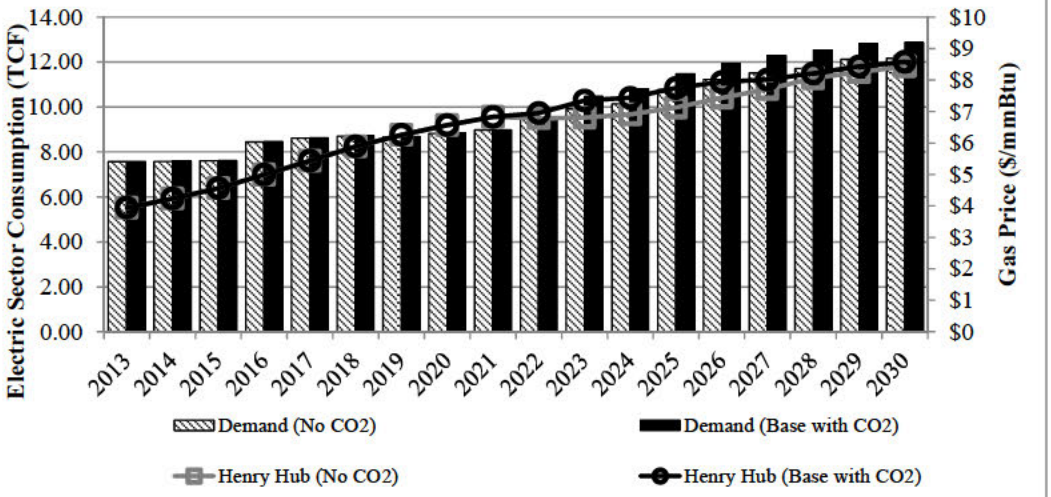


Q. Do any other third party forecast providers included in your review of natural gas and CO_2 price forecasts assume that there is a relationship between natural gas and CO_2 prices?

A. Yes. [redacted] produces a variant to their base case natural gas price forecast that removes the CO_2 price assumptions included in their base case projection. [redacted] assumes in their base case forecast that there is a nominal CO_2 price of $15.59 per ton beginning in 2023 escalating to $26.77 per ton by 2030. Figure R4 below shows [redacted] annual electric sector natural gas consumption and the accompanying Henry Hub natural gas price forecast for their base case forecast inclusive of CO_2 price assumptions and their scenario forecast the removes the base case CO_2 price assumptions. When CO_2 price assumptions are removed, [redacted] forecasts a drop in electric sector demand for natural gas and a corresponding drop in natural gas price. This interaction between CO_2 price, electric sector demand for natural gas, and natural

gas prices is consistent with forecasts produced by EIA in the 2012 AEO and consistent with the adjustments the Company applies to natural gas prices in the scenarios used to evaluate the SCR investments required for Jim Bridger Units 3 and 4.

Figure 4R
Third Party Forecast: Gas Consumption & Gas Price Changes with Varying CO_2 Price Assumptions



Q. What types of third party CO_2 price forecasts do you evaluate in developing a reasonable range of CO_2 price trajectories?

A. When reviewing third party CO_2 price forecasts, we focus on recent projections from reputable forecast services such as [redacted]. As a point of reference, we often compare these forecasts with U.S. EPA's analysis of past policy proposals, focusing on then current baseline projections and any CO_2 price ceilings and floors that may have been included in those proposals. The intent is to provide context for how current price forecasts that take into consideration current market conditions and the current policy

landscape, compare with well-known policy proposals that have been debated in the past.

Q. Have any of the parties to this case suggested the Company review additional CO_2 price forecasts?

A. Yes. Sierra Club describes how Synapse Energy Economics, Inc., the consulting firm that employs Sierra Club witness Dr. Fisher, has reviewed a wide range of CO_2 price assumptions used in IRP and utility dockets over the 2009 – 2012 timeframe and further reviewed government and "other" forecasts to arrive at a range of base, low and high CO_2 price assumptions.[8] Sierra Club suggests that these data show the Company's CO_2 price assumptions are too low. Moreover, Sierra Club testifies that U.S. EPA's analysis of these past policy proposals produced a range of CO_2 price trajectories and that a valid mechanism of evaluating the high and low estimates of a particular bill would be to look at a range of models and range of scenarios.

Q. How do you respond?

A. As noted earlier, the Company has focused its review on *recent* third party forecasts. Reviewing price forecasts used by others for planning purposes dating back to 2009 is not a reasonable means to establish a range of CO_2 price assumptions that take into consideration current market conditions and policy developments. Natural gas prices have a significant impact on prospective CO_2 price levels that would be required to achieve an emissions target. Higher natural gas prices increase the cost of reducing emissions because it increases the cost of transitioning away from coal-fired generation to natural gas-fired generation.

[8] Please refer to the Direct Testimony of Sierra Club witness Dr. Jeremy Fisher at page 14, line 7.

Conversely, lower natural gas prices reduce the cost of achieving emission reductions by reducing the cost of transitioning to natural gas-fired generation, which is more efficient and produces lower CO_2 emissions. Consequently, the CO_2 price required to achieve an emissions target is correlated with the price of natural gas, where, for a given emissions reduction target, high natural gas prices yield a higher CO_2 price and low natural gas prices yield a lower CO_2 price. Given long-term forecasts for natural gas prices have dropped significantly since 2009, CO_2 price assumptions developed as much as four years ago are antiquated and not relevant to current market conditions.

Q. Is it reasonable to consider the entire range of CO_2 price forecasts developed for past legislative proposals?

A. No. It is not reasonable to review the range of CO_2 price trajectories developed by U.S. EPA's analysis of past legislative proposals, which are similarly dated. As I noted above, the range of CO_2 price assumptions used in the Company's scenario analysis for this proceeding are derived off of recent projections that would be aligned with current market conditions. The range is not intended to represent the range of CO_2 price forecasts developed for a specific piece of legislation that was not passed by Congress.

Updated Natural Gas and CO_2 Price Scenario Results

Q. Please describe the results from the updated natural gas and CO_2 price scenarios.

A. The natural gas and CO_2 price scenario results show that the investment in SCRs at Jim Bridger Units 3 and 4 remains favorable to the next best, albeit higher cost

natural gas conversion alternative under all base and high natural gas price scenarios at all assumed CO_2 price levels. In these scenarios, the PVRR(d) ranges between [redacted] favorable to the SCRs (base gas, high CO_2) and [redacted] favorable to the SCRs (high gas, zero CO_2). The PVRR(d) results are unfavorable to the SCRs only in those scenarios where low natural gas prices are assumed.

When low natural gas price assumptions are paired with base CO_2 price assumptions, the nominal levelized price of natural gas at Opal over the period 2016 to 2030 is $3.70 per mmBtu and the PVRR(d) is [redacted] unfavorable to the SCR investments required at Jim Bridger Units 3 and 4. In the low gas zero CO_2 scenario, the nominal levelized price of natural gas at Opal is $3.41 per mmBtu over the 2016 to 2030 timeframe, and the PVRR(d) is [redacted] unfavorable to the SCRs. When low natural gas prices are paired with high CO_2 price assumptions, the nominal levelized price at Opal over the period 2016 to 2030 is $3.78 per mmBtu, and the PVRR(d) is [redacted] unfavorable to the SCRs. The PVRR(d) results from the updated natural gas and CO_2 price scenarios are summarized alongside the base case results in Confidential Exhibit RMP___(RTL-5R) to my rebuttal testimony.

Q. How do the PVRR(d) results trend among the different updated natural gas price assumptions?

A. As demonstrated in the Company's original analysis, the updated scenario results show that there is a strong trend between natural gas price assumptions and the PVRR(d) benefit/cost associated with the incremental pollution control investments required for continued operation of Jim Bridger Units 3 and 4 as

coal-fueled assets. With higher natural gas price assumptions, the incremental SCR investments become more favorable to the Jim Bridger Units 3 and 4 gas conversion alternatives. Conversely, lower natural gas prices improve the PVRR(d) results in favor of the gas conversion alternative. Lower natural gas prices lower the fuel cost of the gas conversion alternative, lowers the fuel cost of the other natural gas-fueled system resources that partially offset the generation lost from the coal-fueled Jim Bridger units, and lowers the opportunity cost of reduced off system sales when Jim Bridger Units 3 and/or 4 operate as a gas-fueled generation assets.

Q. Can you infer from this trend how far natural gas prices would need to fall for gas conversion to become favorable to making the incremental environmental investments in Jim Bridger Units 3 and 4?

A. Yes. Confidential Exhibit RMP___(RTL-6R) to my rebuttal testimony graphically displays the updated relationship between the nominal levelized natural gas price at the Opal market hub over the period 2016 through 2030 and the PVRR(d) benefit/cost of the incremental investments required for continued coal operation of Jim Bridger Units 3 and 4. To isolate the effects of CO_2 prices, which as I described earlier are assumed to elicit a natural gas price response due to changes in demand for natural gas in the electric sector, the natural gas price relationship with PVRR(d) results is shown for the natural gas price scenarios in which the base case CO_2 price assumption is used. Based upon this trend, levelized natural gas prices over the period 2016 through 2030 would need to decrease by 15

percent, from $5.72 per mmBtu to $4.86 per mmBtu, to achieve a breakeven PVRR(d).

Q. Has the Company's natural gas price curve for Opal changed since September 2012?

A. Yes. The nominal levelized natural gas price at Opal from the Company's December 2012 OFPC is $5.54 per mmBtu, which is approximately three percent lower than the updated base case. Based upon the relationship above, the predicted PVRR(d) with the most recent gas prices would be [redacted] and remain favorable to the SCR investments required at Jim Bridger Units 3 and 4.

Q. What CO_2 price would be required to change the PVRR(d) results in favor of converting Jim Bridger Units 3 and 4 to natural gas?

A. Confidential Exhibit RMP___(RTL-7R) to my testimony includes an updated graphical representation of the relationship between the nominal levelized CO_2 price over the period 2016 to 2030 and the PVRR(d) benefit/cost of the incremental investments required for continued coal operation of Jim Bridger Units 3 and 4. To isolate the effects of fundamental shifts in the natural gas price assumptions, the CO_2 price relationship with the PVRR(d) results is shown for the two CO_2 price scenarios that are paired with the same underlying base case natural gas price assumption. Based upon the trend between PVRR(d) and nominal levelized CO_2 price assumptions, the levelized CO_2 prices over the period 2016 through 2030 would need to exceed $30 per ton, more than three times the base case nominal levelized CO_2 price assumption, to achieve a breakeven PVRR(d) for the Jim Bridger Units 3 and 4 SCR investments.

Q. How does the Company use the natural gas and CO_2 price scenario results to inform the Company's decision to pursue the Jim Bridger Units 3 and 4 SCR investments?

A. We first evaluate the magnitude of the PVRR(d) results from the base case, which is defined by assumptions representing the Company's best estimate of forward looking assumptions at any given point in time. The base case results provide an initial look at how favorable or unfavorable the SCR investments are in relation to the next best alternative and provides useful context when reviewing scenario results. The updated base case results summarized earlier in my testimony yield a PVRR(d) that is [redacted] favorable to the Jim Bridger Units 3 and 4 SCRs. This outcome also indicates that when the Company's best estimate of forward looking assumptions are used, there is a reasonably sized "cushion" in the PVRR(d) results allowing for some erosion of the favorable economics should long term natural gas prices or CO_2 prices change from what was assumed in the base case analysis. The natural gas and CO_2 price scenarios are then used to quantify how sensitive the PVRR(d) results are to these key assumptions and provide the foundation for judging risk.

Q. Can you describe how the Company has evaluated risk in the context of the updated results from the natural gas and CO_2 price scenarios?

A. Yes. Confidential Figure 5R below shows the distribution of PVRR(d) results for the base case and the eight natural gas and CO_2 price scenarios. The figure shows that of the nine cases analyzed, six scenarios produce a PVRR(d) favorable to the SCR investments and the three scenarios with low gas price assumptions produce

a PVRR(d) that is unfavorable to the SCR investments. The figure further illustrates the range of potential PVRR(d) outcomes among the scenarios analyzed. At one end of the spectrum, the PVRR(d) for the high gas zero CO_2 scenario is [redacted] favorable to the SCRs. On the other end of the spectrum, the PVRR(d) for the low gas high CO_2 scenario is [redacted] unfavorable to the Jim Bridger Units 3 and 4 SCRs. Among the scenarios analyzed, the distribution of PVRR(d) outcomes indicate a disproportionate risk profile. While there is a possibility evolution of future natural gas prices could render the decision to invest in SCRs to be higher cost than a gas conversion alternative, the cost impacts to customers of such an outcome are higher under a gas conversion alternative should future natural gas prices rise relative to the base case.



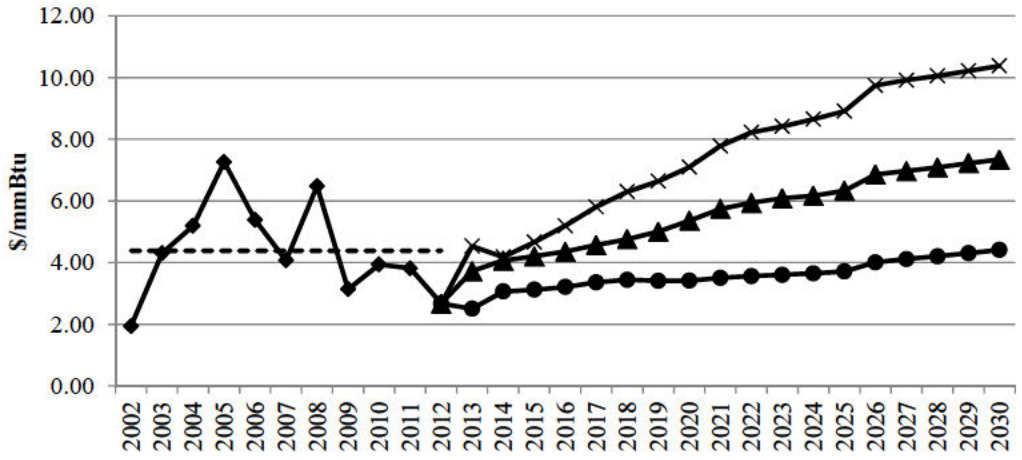
Q. Given the impact of low gas prices on the PVRR(d) results, how have you analyzed the uncertainty around future natural gas prices?

A. A useful metric is to compare the potential range of future natural gas price scenarios in the context of historical natural gas price levels. Figure 6R below plots historical natural gas prices alongside the average annual natural gas price at

the Opal hub among the three low natural gas price scenarios, the three base natural gas price scenarios, and the three high natural gas price scenarios.

Opal natural gas prices among the low natural gas price scenarios never reach 2002 to 2012 historical average price levels over the course of the next 18 years. Among the low natural gas price scenarios, the average annual price for natural gas at Opal over the period 2013 through 2030 is $3.59 per mmBtu, which is 18 percent below 2002 to 2012 historical price levels. Among the base natural gas price scenarios, which are representative of the best estimate of forward looking assumptions, the average annual price for Opal natural gas is $5.66 per mmBtu, or 29 percent above 2002 – 2012 historical price levels. Among the high natural gas price scenarios, Opal natural gas prices average $7.60 per mmBtu, representing a 73 percent increase relative to 2002 to 2012 historical prices.

Figure 6R
Average Annual Natural Gas Prices at Opal



Additional Sensitivities

Q. Were there any other criticisms of the Company's analysis raised by parties in this case?

A. Yes. Sierra Club has taken the position that if Jim Bridger Units 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. WIEC also raises concerns with the Company's Energy Gateway transmission assumptions and with Wyoming wind resource additions that are included in the Company's analysis.

Q. What assumptions for Energy Gateway transmission are included in the Company's analysis?

A. The base case and scenario analyses performed by the Company assume that all segments of the Energy Gateway project will be implemented, including Gateway West, which connects Windstar to Populus and Populus to Hemmingway.

Q. Are any of the Energy Gateway transmission segments driven by the decision to install SCR equipment on Jim Bridger Units 3 and 4?

A. No. The decision to install SCR equipment at the Jim Bridger plant is not influential to the decision-making process for Energy Gateway transmission investments. Independent of the decision to install SCRs at the Jim Bridger facility, the Gateway West segment will provide reliability benefits, increase

access to low cost generation resources, and allow for a more efficient use of system resources.

Q. Have any of the parities suggested an alternative to how Energy Gateway assumptions are implemented in the SO Model simulations?

A. Yes. Sierra Club testifies that the Company could use the SO Model to evaluate avoided transmission investments if Jim Bridger were retired and states:

> …the Company could have simply de-activated these extraneous "transmission options" in the model scenario where Jim Bridger is retired, and evaluated the total cost without these links.[9]

Sierra Club believes that the Energy Gateway investments should be included in the SO Model simulation where Jim Bridger Units 3 and 4 continue operating as coal, and removed in an SO Model simulation where Jim Bridger Units 3 and 4 are retired early.

Q. How do you respond?

A. Sierra Club's recommended approach to model Energy Gateway investments in the SO Model is fundamentally flawed. At the heart of Sierra Club's recommendation is the belief that the only reason for the Gateway West project is to export energy from Wyoming west to Populus. This is not a valid assumption, and if this modeling approach were implemented, it would inappropriately assign *all* of the cost savings associated with removing Energy Gateway investments to the case where Jim Bridger Units 3 and 4 are assumed to retire early without accounting for the loss of incremental benefits that the Gateway investments would provide.

[9] Please refer to the Direct Testimony of Sierra Club witness Dr. Jeremy Fisher at page 31, line 19.

Q. What types of benefits does the Energy Gateway project provide?

A. PacifiCorp's transmission system is a major component of the Western Interconnection, and the Energy Gateway project would allow the Company to more efficiently dispatch system resources, improve performance of the transmission system (i.e. reduced line losses), improve reliability, and allow the Company to access a diverse range of new resource alternatives over the long-term. Moreover, the Energy Gateway project would contribute to meeting the reliability needs of the region overall. Sierra Club has simply failed to recognize the breadth of the long-term benefits associated with the Energy Gateway project in its oversimplified assessment of transmission costs as it pertains to the SCR equipment being analyzed in this proceeding.

Q. Did WIEC attempt to analyze the impact of Energy Gateway on the SCR investment decisions at Jim Bridger Units 3 and 4?

A. Yes. WIEC performed a GRID study to evaluate how removal of the Gateway West and South Segments would impact the PVRR(d) associated with the Jim Bridger Units 3 and 4 SCR investments.

Q. Did WIEC implement the approach recommended by Sierra Club as you described above?

A. No. Sierra Club suggests that the different Energy Gateway assumptions should be applied to the two simulations required to calculate a PVRR(d) – one simulation where Jim Bridger Units 3 and 4 continue operating as coal-fueled assets, and one simulation where Jim Bridger Units 3 and 4 are forced to retire early. WIEC's GRID study removed the Gateway West and South Segments in

both GRID simulations needed to calculate the PVRR(d) associated with the SCR equipment.

Q. What were WIEC's findings from this analysis?

A. WIEC found that the Gateway Project does not materially affect the value of Jim Bridger Units 3 and 4 whether operating as coal- or gas-fueled assets. WIEC summarizes these findings in its testimony, suggesting that their analysis provides evidence that the Energy Gateway investments should not be constructed.

Q. Has the Company included in its CPCN any funds related to the Energy Gateway project?

A. No.

Q. Is the Company seeking pre-approval for any of the Energy Gateway projects in this proceeding?

A. No.

Q. Did WIEC raise any additional concerns with the Company's analysis related to long-term planning uncertainties?

A. Yes. WIEC questions the Company's assumptions for projected incremental wind resource additions located in Wyoming that would be used to satisfy known state and potential federal renewable portfolio standard requirements. In particular, WIEC questions whether the incremental wind resources assumed to be located in Wyoming would affect the Company's analysis of the SCR equipment required at Jim Bridger Units 3 and 4.

Q. Has the Company performed additional sensitivities in response to parties' concerns on Energy Gateway and wind resource assumptions?

A. Yes. As a variant of the updated base case analysis, the Company performed a PVRR(d) sensitivity that removes Gateway West and South transmission and all incremental wind from Wyoming.

Q. What are the results of this sensitivity analysis?

A. As compared to the updated base case, this sensitivity improves the economics of the continued coal-fueled operation case resulting in a PVRR(d) that is [redacted] favorable to the Jim Bridger Units 3 and 4 SCR investments. The sensitivity shows that the Energy Gateway assumptions and Wyoming wind resource assumptions do not adversely affect base case results supporting the SCR investments.

Q. Does the Company's base case and scenario analyses allow for early retirement as an alternative to the SCR investments?

A. Yes. The PVRR(d) is calculated by taking the difference in system costs between two SO Model simulations. One simulation assumes the SCR investments are made and Jim Bridger Units 3 and 4 continue operating as coal-fueled assets. The second simulation forces Jim Bridger Units 3 and 4 to stop operating as coal-fueled assets, allowing the model to choose among the most economical alternative to the SCR investments, which includes gas conversion and early retirement. In all of our simulations, the SO Model chose gas conversion over early retirement when it is assumed the SCR investments are not made.

Q. Has the Company performed an additional sensitivity that shows gas conversion is a lower cost SCR alternative than early retirement with a replacement resource located closer to load centers?

A. Yes. For this sensitivity, in the case where Jim Bridger Units 3 and 4 stop operating as coal-fueled assets, we forced each unit to retire (not allowing it to choose gas conversion) for purposes of calculating the PVRR(d).

Q. What are the results of this sensitivity analysis?

A. When Jim Bridger Units 3 and 4 are forced to retire early the SO Model adds a 597 MW combined cycle unit located in southern Utah in 2017.[10] As compared to an early retirement alternative, the PVRR(d) is [redacted] in favor of the Jim Bridger Units 3 and 4 SCR investments. The sensitivity also shows that gas conversion, while unfavorable to the SCR investments, has a PVRR(d) that is [redacted] favorable to early retirement.

Conclusion

Q. Please summarize the conclusions of your testimony.

A. The conclusions of my testimony are as follows:

- The updated base case analysis results in a PVRR(d) that is [redacted] favorable to the Jim Bridger Units 3 and 4 SCR investments as compared to a gas conversion alternative.
- Additional sensitivity analysis shows a PVRR(d) that is [redacted] favorable to the Jim Bridger Units 3 and 4 SCR investments as compared to an early retirement and resource replacement alternative.

[10]Incremental front office transactions are also included in the portfolio when Jim Bridger Units 3 and 4 are forced to retire early.

- Updated natural gas and CO_2 price scenario results continue to support the SCR investments, with all scenarios but those with low natural gas price assumptions, which do not reach historical price levels for the next 18 years, showing a PVRR(d) that favors the installation of SCRs.
- The Company's analysis has been updated to correct for errors and to reflect current assumptions that do not require manual adjustments to SO Model results, better align with assumptions used in net power cost filings, and incorporate contributions to the mine reclamation trust through 2037.
- Additional sensitivity analysis shows that alternative Energy Gateway transmission assumptions and Wyoming wind resource assumptions improve the PVRR(d) results in favor of the SCR investments.

Q. What do you recommend?

A. I recommend that the Commission approve the CPCN based on the information and analyses presented in the case.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Docket No. UE 374
Exhibit Sierra Club/105
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 105

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

WY DEQ Bart Appeal Settlement Agreement

BART APPEAL SETTLEMENT AGREEMENT

The Wyoming Department of Environmental Quality, Air Quality Division (the "DEQ/AQD") and PacifiCorp Energy, a division of PacifiCorp ("PacifiCorp"), enter into this BART Appeal Settlement Agreement (the "Settlement Agreement") to fully and finally resolve PacifiCorp's appeal before the Wyoming Environmental Quality Council (the "EQC") in Docket No. 10-2801 wherein PacifiCorp challenged certain conditions of BART permit Nos. MD-6040 and MD-6042 for the Jim Bridger and Naughton power plants. The DEQ/AQD and PacifiCorp are collectively referred to herein as the "Parties" and sometimes individually as "Party." The Settlement Agreement shall be effective between the Parties on the date that the last signature is affixed below (the "Effective Date"), conditioned on approval by the EQC as described herein.

Wyo. Stat. 16-3-107(n) and Chapter I, § 11 of the DEQ's Rules of Practice & Procedure provide for the disposition of this contested case by stipulation of the Parties upon approval by the EQC. Additionally, Wyo. Stat § 35-11-112 empowers the EQC to order the modification of BART Permit Nos. MD-6040 and MD-6042 to resolve this contested case. To that end, PacifiCorp and the DEQ/AQD, conditioned on the approval of the EQC, hereby stipulate and agree as follows.

1. **Background:** As part of its obligation under the Clean Air Act's Regional Haze Program, the State of Wyoming, through the DEQ/AQD, promulgated regulations requiring the installation of Best Available Retrofit Technology ("BART") on certain eligible facilities. PacifiCorp timely complied with these regulations by filing applications for BART permits for its eligible facilities, including an application for its Bridger power plant on January 16, 2007, and its Naughton power plant on February 12, 2007. PacifiCorp further filed additional information with the DEQ/AQD relating to these applications. Following public notice and comment, and public hearings, the DEQ/AQD issued BART permit Nos. MD-6040 for the Bridger power plant and MD-6042 for the Naughton power plant on December 31, 2009. On February 26, 2010, PacifiCorp timely filed an appeal to the EQC of certain provisions in BART permit Nos. MD-6040 and MD-6042. Litigation ensued, including discovery and motion practice. This Settlement Agreement resolves all issues raised in that litigation. Also, in connection with this Settlement Agreement, PacifiCorp has provided to DEQ/AQD the information attached as Exhibit A which the parties intend to be used in the Wyoming Regional Haze SIP as that term is described below.

2. **Definitions:** As used in this Agreement, the following terms are defined as:

   "BART Permit Appeal" means: PacifiCorp's Appeal and Petition for Review of BART Permits regarding the Bridger BART Permit and the Naughton BART Permit, referred to as Docket No. 10-2801, before the EQC.

   "BART Appeals Arguments" means: The arguments raised by PacifiCorp in the BART Permit Appeal, including its Motion for Partial Summary Judgment and

supporting Memorandum, filed June 30, 2010, and its Reply in Support of Its Motion for Partial Summary Judgment, filed August 31, 2010.

"Naughton BART Permit" means: BART permit No. MD-6042 as issued by the DEQ/AQD on December 31, 2009.

"Bridger BART Permit" means: BART permit No. MD-6040 as issued by the DEQ/AQD on December 31, 2009.

"Wyoming Regional Haze SIP" means: the final version of the Wyoming State Implementation Plan regarding "regional haze" and addressing regional haze requirements for Wyoming mandatory Class 1 areas under 40 CFR §51.309(g) as prepared by the DEQ/AQD and submitted to EPA for review and approval. As of the date of this Settlement Agreement, the DEQ/AQD has not completed the final version of the Wyoming Regional Haze SIP and instead has prepared a draft of that document dated August 25, 2009, which DEQ/AQD released previously for public comment. Based in part on those comments, DEQ/AQD intends to release an updated version of the draft Wyoming Regional Haze SIP for additional public comment before the end of 2010.

3. **Agreement:** The Parties have engaged in negotiations to reach a settled resolution to this contested case. The Parties have agreed, upon the terms contained herein, to settle and compromise PacifiCorp's BART Permit Appeal, including the BART Appeals Arguments.

4. **Performance by PacifiCorp:** In reliance upon the releases, agreements, and representations of the DEQ/AQD in this Settlement Agreement, and conditioned upon the EQC's approval of this Settlement Agreement and its terms, PacifiCorp shall do the following:

   (a) Naughton - PacifiCorp shall withdraw its BART Appeals Arguments regarding the Naughton power plant, dismiss its BART Permit Appeal as it relates to the Naughton power plant, and agree to abide by the terms of the Naughton BART Permit;

   (b) Bridger - PacifiCorp shall withdraw its BART Appeals Arguments regarding the Bridger power plant, dismiss its BART Permit Appeal as it relates to the Bridger power plant, and agree to abide the terms of the Bridger BART Permit as modified by the EQC in accordance with this Settlement Agreement, including the removal of Conditions 17 and 18;

   (c) NOx Control for Bridger Units 3 and 4 – With respect to Bridger Units 3 and 4, PacifiCorp shall: (i) install SCR; (ii) install alternative add-on NOx control systems; or (iii) otherwise reduce NOx emissions to achieve a 0.07 lb/mmBtu 30-day rolling average NOx emissions rate. These installations shall occur, and/or this emission rate will be achieved, on Unit 3 prior to

December 31, 2015 and Unit 4 prior to December 31, 2016. These installations shall occur, and/or this emission rate will be achieved, in conjunction with PacifiCorp's planned overhaul schedule for these units and pursuant to a construction or other permit application to be submitted by PacifiCorp to AQD no later than December 31, 2012; and

(d) NOx Control for Bridger Units 1 and 2 -- With respect to Bridger Units 1 and 2, PacifiCorp shall: (i) install SCR; (ii) install alternative add-on NOx control systems; or (iii) otherwise reduce NOx emissions not to exceed a 0.07 lb/mmBtu 30-day rolling average NOx emissions rate. These installations shall occur, and/or this emission rate will be achieved, on Unit 2 prior to December 31, 2021 and Unit 1 prior to December 31, 2022. These installations shall occur, and/or this emission rate will be achieved, in conjunction with PacifiCorp's planned overhaul schedule for these units and pursuant to a construction or other permit application to be submitted by PacifiCorp to AQD no later than December 31, 2017.

5. **Performance by the DEQ/AQD:** In reliance upon the releases, agreements and representations of PacifiCorp in this Settlement Agreement, and conditioned upon the EQC's approval of this Settlement Agreement and its terms, the DEQ/AQD shall do the following:

(a) Naughton – The DEQ/AQD shall, pursuant to an order by the EQC approving this Settlement Agreement, include in the Wyoming Regional Haze SIP a statement explaining that the cost of the Naughton Unit 3 baghouse is reasonable when considering all factors relating to the existing PM controls in addition to those considered during the BART analysis.

(b) Bridger – The DEQ/AQD shall, pursuant to an order by the EQC approving this Settlement Agreement, delete Conditions 17 and 18 from the Bridger BART Permit and, in lieu of Conditions 17 and 18, adopt the requirements of paragraphs 4(c) and 4(d) of this Settlement Agreement into the Wyoming Regional Haze SIP as part of Wyoming's Long-Term Strategy and/or Reasonable Progress Goals; and

(c) PacifiCorp's Compliance with BART and LTS Requirements - The DEQ/AQD shall not require further PM or NOx reductions at Naughton Unit 3, or require further NOx reductions at Bridger Units 1 – 4, for purposes of meeting BART, Long-Term Strategy requirements and/or Reasonable Progress Goals in the Wyoming Regional Haze SIP through 2023.

6. **Conditions of Settlement:** The Parties' duties, rights and obligations of this Settlement Agreement are conditioned upon, and the Parties shall in good faith cooperate to achieve, the following:

(a) The EQC and any other required Wyoming governing authority must approve this Settlement Agreement and its terms;

(b) PacifiCorp and the DEQ/AQD must file a joint stipulated motion with the EQC requesting dismissal of PacifiCorp's BART Permit Appeal, and the EQC must dismiss the BART Permit Appeal on approval of the terms contained herein subject only to EQC's continuing jurisdiction as described in Section 7 below;

(c) The EQC must order the Bridger BART Permit be modified as required herein; and

(d) EPA must approve those portions of the Wyoming Regional Haze SIP that are consistent with the terms of this Settlement Agreement. Provided, however, that unless EPA affirmatively disapproves such portions of the Wyoming Regional Haze SIP in a final rulemaking, the parties shall continue to abide by the terms of this Settlement Agreement.

7. **Changed Circumstances:** The Parties agree that this Settlement Agreement may be subject to modification if future changes in either: (i) federal or state requirements or (ii) technology would materially alter the emissions controls and rates that otherwise are required hereunder. In that case, either Party may request that the other Party enter into an amendment to this Settlement Agreement consistent with such changes. The Parties shall negotiate in good faith to amend the affected Settlement Agreement provision(s) consistent with the changed federal or state requirements or technology and with the purposes of this Settlement Agreement. If the Parties cannot agree on the proposed amendment, then either Party may request the EQC to determine if the proposed amendment is consistent with the changed federal or state requirements or technology and with the purposes of this Settlement Agreement. In that case, the Parties anticipate that the EQC determination will be incorporated into an EQC order that requires the Parties to proceed in accordance with its terms, including the possibility of entering into the proposed amendment. The Parties further anticipate that the EQC will retain continuing jurisdiction over the BART Permit Appeal and this Settlement Agreement for the foregoing purposes only.

8. **Reservation of Rights:** PacifiCorp reserves the right to appeal or challenge any actions by AQD, EQC or EPA that are inconsistent with this Settlement Agreement. In addition, if the EQC takes any action which is materially inconsistent with or in any way materially alters this Settlement Agreement, then this Settlement Agreement shall be voidable at the option of the Party materially affected by the EQC's actions.

9. This Settlement Agreement shall be admissible by either Party without objection by the other Party in any subsequent action between these Parties to enforce the terms hereof or as otherwise required herein.

10. Neither Party shall have any claim against the other for attorney fees or other costs incurred with the issues resolved. Each Party shall bear its own attorney fees and costs, if any, incurred in connection with the BART Permit Appeal and this Settlement Agreement. Each Party assumes the risk of any liability arising from its own conduct. Neither Party agrees to insure, defend or indemnify the other.

11. This Settlement Agreement is binding upon PacifiCorp, its successors and assigns, and upon the DEQ/AQD.

12. This Settlement Agreement may only be amended in writing, signed by both Parties.

13. Neither the DEQ/AQD nor the State of Wyoming nor any of its Agencies shall be held as a party to any contracts or agreements entered into by PacifiCorp to implement any condition of this Agreement.

14. Nothing in this Agreement relieves PacifiCorp of its duty to comply with all applicable requirements under the Wyoming Environmental Quality Act (WEQA), and rules, regulations, and standards adopted or permits issued thereunder. DEQ/AQD does not warrant or aver that PacifiCorp's completion of any aspect of this Agreement will result in compliance with the WEQA and rules, regulations and standards adopted or permits issued thereunder.

15. The State of Wyoming and the DEQ/AQD do not waive sovereign immunity by entering into this Settlement Agreement, and specifically retain all immunity and all defenses to them as sovereigns pursuant to Wyo. Stat. §1-39-104(a) and all other state law.

16. The Parties do not intend to create in any other individual or entity the status of third party beneficiary, and this Agreement shall not be construed so as to create such status. The rights, duties and obligations contained in this Agreement shall operate only among the Parties to this Agreement.

17. Should any portion of this Agreement be judicially determined to be illegal or unenforceable, the remainder of this Agreement shall continue in full force and effect, and either Party may renegotiate the terms affected by the severance.

18. The construction, interpretation and enforcement of this Agreement shall be governed by the laws of the State of Wyoming. The Courts of the State of Wyoming shall have jurisdiction over this Agreement and the parties, and the venue shall be the First Judicial District, Laramie County, Wyoming.

19. This Agreement may be executed in any number of separate counterparts any one of which need not contain the signatures of more than one Party but all of such

counterparts together will constitute one Agreement. The separate counterparts may contain original, photocopy, or facsimile transmissions of signatures.

20. The persons signing this Settlement Agreement certify that they are duly authorized to bind their respective Party to this Settlement Agreement.

21. This agreement is not binding between the Parties until fully executed by each Party.

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PACIFICORP ENERGY, a division of PacifiCorp

By: _____

Name: DANA RALSTON

Title: VICE PRESIDENT GENERATION

Date: 11-2-2010

THE WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY

By: _____

Name: JOHN V. CORRA

Title: Director

Date: 11/3/10

THE WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY/DIVISION OF AIR QUALITY

By: _____

Name: STEVEN A. DIETRICH

Title: AQD - ADMINISTRATOR

Date: 11-3-10

Approved As To Form

_____
Nancy E. Vehr,
Senior Assistant Attorney General

Docket No. UE 374
Exhibit Sierra Club/106
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 106

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

PacifiCorp Emission Reduction Plan

November 2, 2010

Exhibit A

PacifiCorp's Emissions Reductions Plan

In connection with its Best Available Retrofit Technology ("BART") determinations and its other regional haze planning activities, the Wyoming Department of Environmental Quality, Air Quality Division ("AQD") asked PacifiCorp to provide additional information about its overall emission reduction plans through 2023. The purpose is to more fully address the costs of compliance on both a unit and system-wide basis. PacifiCorp is committed to reduce emissions in a reasonable, systematic, economically sustainable and environmentally sound manner while meeting applicable legal requirements. These legal requirements include complying with the regional haze rules which encompass a national goal to achieve natural visibility conditions in Class 1 areas by 2064

Summary

PacifiCorp owns and operates 19 coal-fueled generating units in Utah and Wyoming, and owns 100% of Cholla Unit 4, which is a coal-fueled generating unit located in Arizona. PacifiCorp is in the process of implementing an emission reduction program that has reduced, and will continue to significantly reduce emissions at its existing coal-fueled generation units over the next several years. From 2005 through 2010 PacifiCorp has spent more than $1.2 billion in capital dollars. It is anticipated that the total costs for all projects that have been committed to will exceed $2.7 billion by the end of 2022. The total costs (which include capital, O&M and other costs) that will have been incurred by customers to pay for these pollution control projects during the period 2005 through 2023, are expected to exceed $4.2 billion, and by 2023 the annual costs to customers for these projects will have reached $360 million per year.

Environmental benefits, including visibility improvements will flow from these planned emission reductions. PacifiCorp believes that the emission reduction projects and their timing appropriately balance the need for emission reductions over time with the cost and other concerns of our customers, our state utility regulatory commissions, and other stakeholders. PacifiCorp believes this plan is complementary to and consistent with the state's BART and regional haze planning requirements, and that it is a reasonable approach to achieving emission reductions in Wyoming and other states.

PacifiCorp's Long-Term Emission Reduction Commitment

Table 1 below identifies the emission reduction projects and related construction schedules as currently included in PacifiCorp's reduction plan.

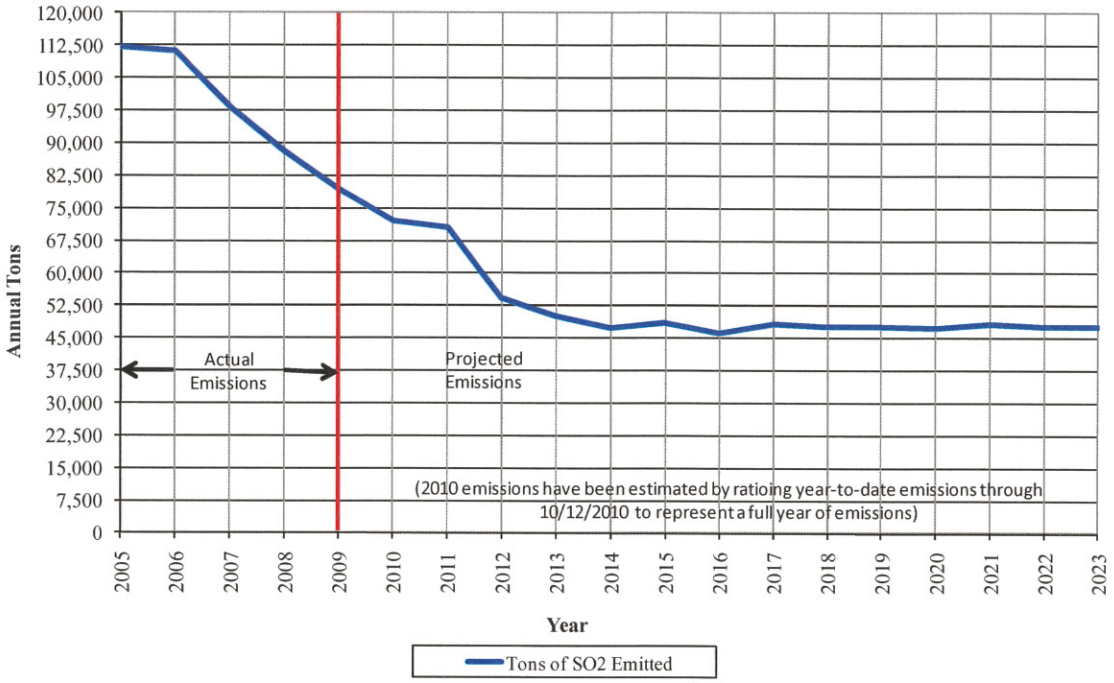
Table 1: Long-Term Reduction Plan

Plant Name	SO2 Scrubbers Installation - I Upgrades - U	Low NOx Burner Installations	Baghouse Installations	Status of SO2 / LNB / Baghouse Permitting	Selective Catalytic Reduction
Hunter 1	2014 - U	2014	2014	Permitted	
Hunter 2	2011 - U	2011	2011	Under Construction	
Hunter 3	Existing	2008	Existing	Completed	
Huntington 1	2010 - U	2010	2010	Under Construction	
Huntington 2	2007 - I	2007	2007	Completed	
Dave Johnston 3	2010 - I	2010	2010	Completed	
Dave Johnston 4	2012 - I	2009	2012	Under Construction	
Jim Bridger 1	2010 - U	2010		Completed	2022
Jim Bridger 2	2009 - U	2005		Completed	2021
Jim Bridger 3	2011 - U	2007		Permitted	2015
Jim Bridger 4	2008 - U	2008		Completed	2016
Naughton 1	2012 - I	2012		Under Construction	
Naughton 2	2011 - I	2011		Under Construction	
Naughton 3	2014 - U	2014	2014	Baghouse Permitted	2014
Wyodak	2011 - U	2011	2011	Under Construction	
Cholla 4	2008 - U	2008	2008	Completed	

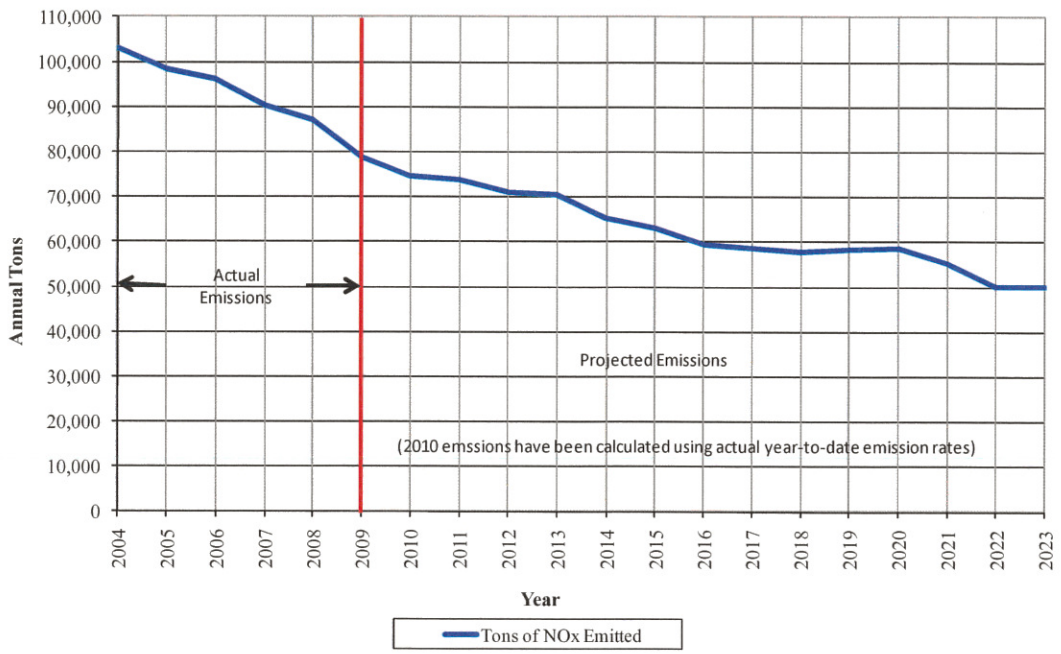
The following charts represent the reductions in emissions that will occur at units owned by PacifiCorp in Utah, Wyoming and Arizona[1]. It is significant to note that permitting has been completed for all but the SCR projects; permitting for the SCR projects will be completed as needed in advance of project construction. The emission estimates shown in these charts have been calculated using projected unit generation and heat rate data in conjunction with each unit's permitted emission rate. In those cases were the units do not have emissions controls the estimates have been based on projections of the future coal quality. All projections used are from PacifiCorp's ten-year business plan. Actual future emissions will be less than those estimated in these charts since the units will operate below their permitted rates.

[1] PacifiCorp is also a joint owner of coal-fueled facilities in Colorado and Montana that are subject to regional haze planning requirements and for which PacifiCorp will incur associated costs of emissions controls.

2005 - 2009 Actual and 2010 - 2023 Projected SO2 Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units



2004 - 2009 Actual and 2010 - 2023 Projected NOx Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units



Project Installation Schedule

Emission reduction projects of the number and size described above take many years to engineer, plan and build. When considering a fleet the size of PacifiCorp's, there is a practical limitation on available construction resources and labor. There is also a limit on the number of units that may be taken out of service at any given time as well as the level of construction activities that can be supported by the local infrastructures at and around these facilities. Such limitations directly impact both the overall timing of these projects as well as their timing in relation to each other. Additional cost and construction timing limitations include the loss of large generating resources during some parts of construction and the associated impact on the reliability of PacifiCorp's electrical system during these extended outages. In other words, it is not practical, and it is unduly expensive, to expect to build these emission reduction projects all at once or even in a compressed time period. The pressure on emission reduction equipment and skilled labor is likely to be exacerbated by the significant emission reduction requirements necessitated by the Environmental Protection Agency's Clean Air Transport Rule which requires emission reductions in 31 Eastern states and the District of Columbia beginning in 2012 and 2014. The Environmental Protection Agency has indicated that a second Transport Rule is likely to be issued in 2011, requiring additional reductions in the Eastern U.S. beyond those effective in 2014. The balancing of these concerns is reflected in the timing of PacifiCorp's emission reduction commitments.

Priority of Emission Reductions

PacifiCorp's initial focus has been on installing controls to reduce SO_2 emissions which are the most significant contributors to regional haze in the western US. In addition, PacifiCorp continues to rely on the rapid installation of low NO_x burners to significantly reduce NOx emissions. Also, the installation of five SCRs (or similar NOx-reducing technologies) will be completed by 2023 and reduce NOx emissions even further. PacifiCorp's commitment also includes the installation of several baghouses to control particulate matter emissions. For those units which utilize dry scrubbers, baghouses have the added benefit of improving SO2 removal. Baghouses also significantly reduce mercury emissions.

In addition to reducing emissions at existing facilities, PacifiCorp has avoided increasing emissions by adding more than 1,400 megawatts of renewable generation between 2006 and 2010. In order to meet growing demand for electricity, PacifiCorp added non-emitting wind generation to its portfolio at a cost of over $2 billion and has dismissed further consideration of a new coal-fueled unit.

Emission Reductions and BART Deadlines

As depicted in the table and charts above, PacifiCorp began implementing its emission reduction commitments in 2005. This was well ahead of the emission reduction timelines under the regional haze rules which require BART to be installed no later than five years following approval of the applicable Regional Haze SIP. This also provides a graphic demonstration of the construction schedule and other limitations described above, as PacifiCorp was required to begin installing emission control projects at some units earlier in order to complete projects at other

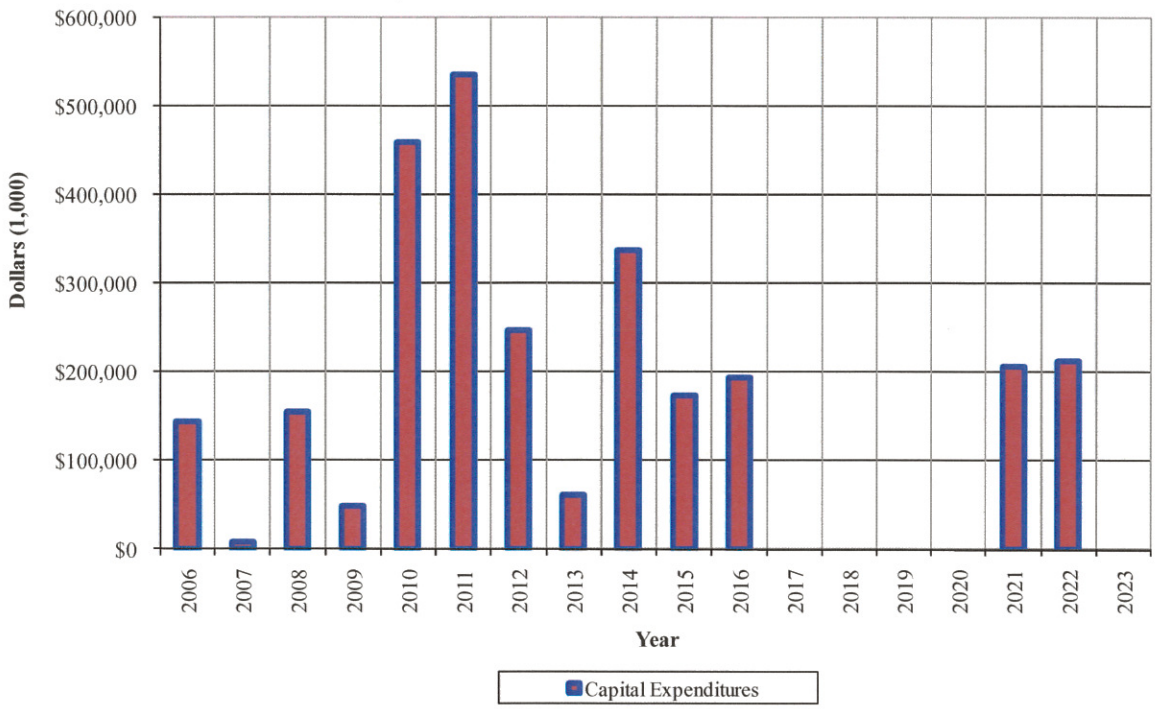
units within the five years after SIP approval. The table above demonstrates that most of the projects to be built between 2010 and 2014, likewise, will be installed in advance of the required completion date under BART requirements.

Customer Impacts

The following charts identify the timing and magnitude of the capital and O&M expenses that will be incurred due to the projects identified in Table 1. The charts identify:

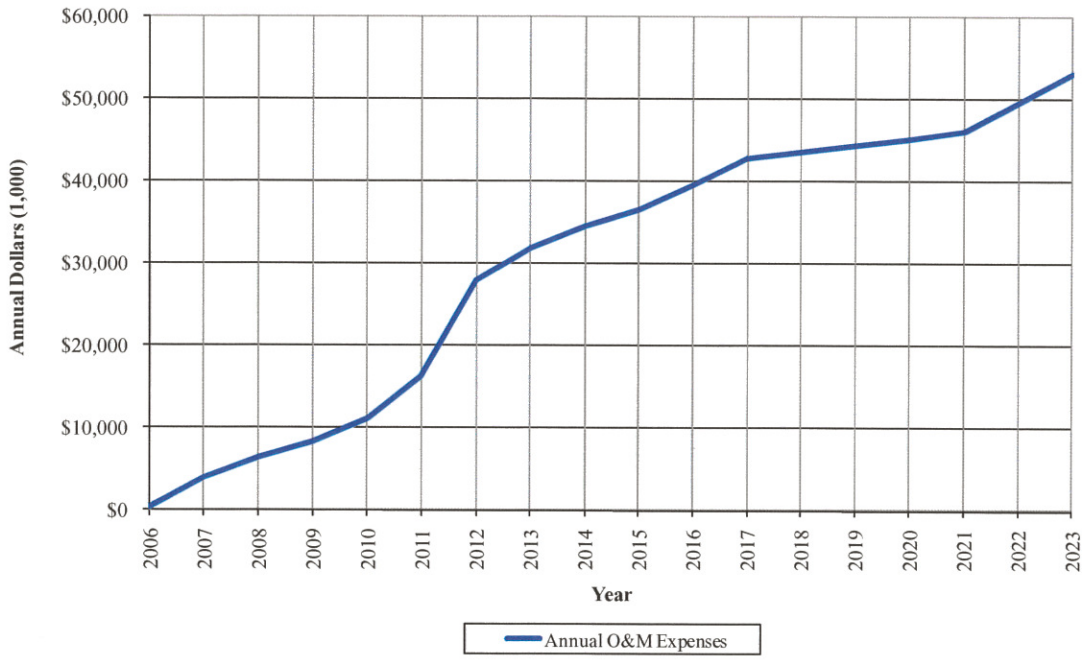
1. The timing and magnitude of the capital costs.
2. The O&M expenses that will be incurred due to these projects.
3. The expected annual costs[2] through 2023 that customers will be incur as a result of these specific pollution control projects.

Capital Expenditures to Add Pollution Control Equipment onPacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units

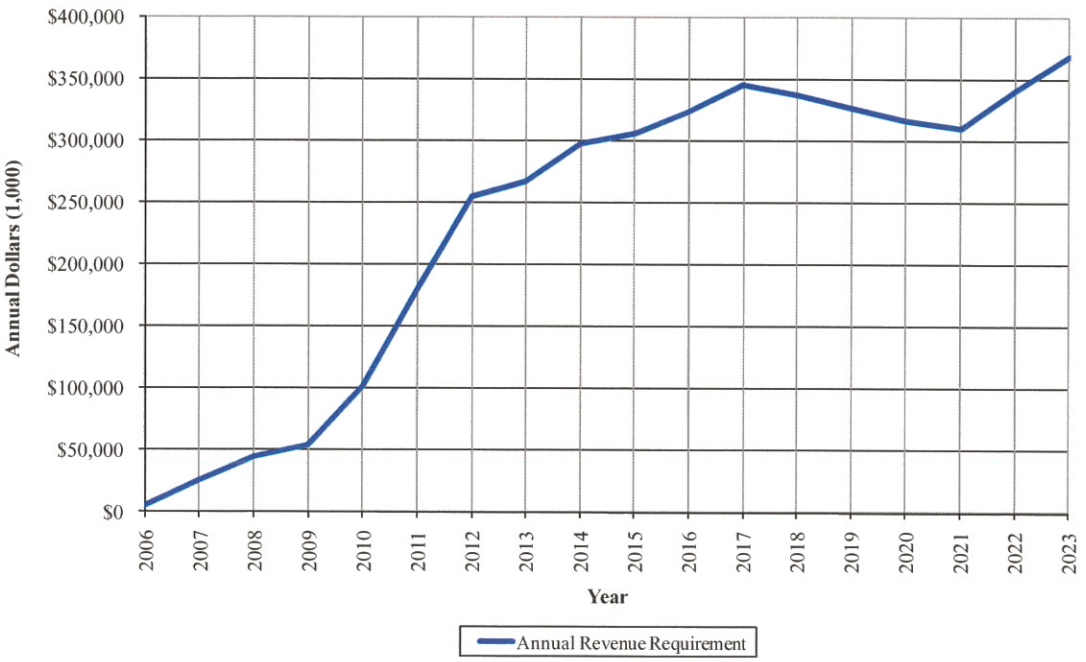


[2] PacifiCorp has made every attempt to provide an accurate estimate of the anticipated increase in annual revenue requirements that will ultimately be translated to increases in customers' electricity rates. However, there are several variables such as interest rates, inflation rates, discount rates, depreciation lives, and final construction costs and operating and maintenance expenses that will be considered at the time these projects actually go into rate base and will influence the actual revenue requirements associated with these capital projects.

Increases In O&M Expenses Due to Additional Pollution Control Equipment on Arizona, Utah & Wyoming Coal-Fired Units



Annual Increase to Customers Due to Additional Pollution Control Equipment on Arizona, Utah & Wyoming Coal-Fired Units



As can be seen from the previous charts, the rate increases for PacifiCorp customers associated with PacifiCorp's emission reduction strategy alone will be significant. In the event that PacifiCorp is required to accelerate or add to the planned emission reduction projects, the cost impacts to our customers can be expected to increase incrementally, particularly as plant outage schedules are extended and the need for skilled labor and material increases in the near term.

Of particular note, the projected costs reflect only the installation of the noted emission reduction equipment. These cost increases do not include other costs expected to be incurred in the future to meet further emission reduction measures or address other environmental initiatives, including but not limited to (see Attachment 1):

1. Implementation of Utah's Long Term Strategy for meeting regional haze requirements during the 2018-2023 time period.

2. The addition of mercury control equipment under the requirements of the upcoming mercury MACT provisions. PacifiCorp estimates that $68 million in capital will be incurred by 2015 and annual operating expenses will increase by $21million per year to comply with mercury reduction requirements. In addition, anticipated regulation to address non-mercury hazardous air pollutant (HAPs) emissions may require significant additional reductions of SO_2, as a precursor to sulfuric acid mist, from non-BART units that currently do not have specific controls to reduce SO_2 emissions.

3. Mitigating and controlling CO_2 emissions. While Congress has not yet passed comprehensive climate change legislation, in December 2009, the Administrator of the Environmental Protection Agency made a finding that greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations. Having made the so-called "endangerment finding," EPA issued the final greenhouse gas tailoring rule, effective January 2, 2011, which will require greenhouse gas emissions to be addressed under PSD and Title V permits[3]. Likewise, mandatory reporting of greenhouse gas emissions to the Environmental Protection Agency commenced beginning in January 2010.

4. In addition, there are a number of regional regulatory initiatives, including the Western Climate Initiative that may ultimately impact PacifiCorp's coal-fueled facilities. PacifiCorp's generating units are utilized to serve customers in six states – Wyoming, Idaho, Utah, Washington, Oregon and California. California, Washington and Oregon are participants in the Western Climate Initiative, a comprehensive regional effort to reduce greenhouse gas emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector; each state has implemented state-level emissions reduction goals. California, Washington and Oregon have also adopted greenhouse gas emissions performance standards for base load electrical generating resources under which emissions must not exceed 1,100 pounds of CO_2 per megawatt

[3] The Environmental Protection Agency has not yet published its proposed guidance on what constitutes Best Available Control Technology for greenhouses gases.

hour. The emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of 5 or more years) unless the base load generation supplied under long-term financial commitments comply with the greenhouse gas emissions performance standards. While these requirements have not been implemented in Wyoming, due to the treatment of PacifiCorp's generation on a system-wide basis (i.e., electricity generated in Wyoming may be deemed to be consumed in California based on a multi-state protocol), PacifiCorp's facilities may be subject to out-of-state requirements.

5. Regulations associated with coal combustion byproducts. In June 2010, the Environmental Protection Agency published a proposal to regulate the disposal of coal combustion byproducts under the Resource Conservation and Recovery Act's Subtitle C or D. Under either regulatory scenario, regulated entities, including PacifiCorp, would be required, at a minimum; to retrofit/upgrade or discontinue utilization of existing surface impoundments within five years after the Environmental Protection Agency issues a final rule and state adoption of the appropriate controlling regulations. It is anticipated that the requirements under the final rule will impose significant costs on PacifiCorp's coal-fueled facilities within the next eight to ten years.

6. The installation of significant amounts of new generation, including gas-fueled generation and renewable resources.

7. The addition of major transmission lines to support the renewable resources and other added generation.

8. Increasing escalation rates on fuel costs and other commodities

BART and Regional Haze Compliance

PacifiCorp firmly believes that the commitments described above meet the letter and intent of the regional haze rules, including the guidance provided by the EPA known as "Appendix Y." The regional haze program is a long-term effort with long-term goals ending in 2064. It must be approached from that perspective. It was never intended to require SCR on BART-eligible units within the first five years of the program. Rather, it calls for a transition to lower emissions exactly as PacifiCorp has implemented to date and as it has proposed going forward through 2023.

In its evaluation of emission reductions for regional haze purposes, the state should also consider several other variables which will significantly affect emissions and costs over the next ten years. These include such things as the development of new emission control technology, anticipated new emission reduction legislation and rules, the new ozone standard, the one hour SO_2 and NO_2 standards, the $PM_{2.5}$ standard, potential CO_2 regulation and costs, an aging fleet, and changing economic conditions. All of these variables matter and will affect the long-term viability of each PacifiCorp coal unit and will contribute to the reduction of regional haze in the course of the

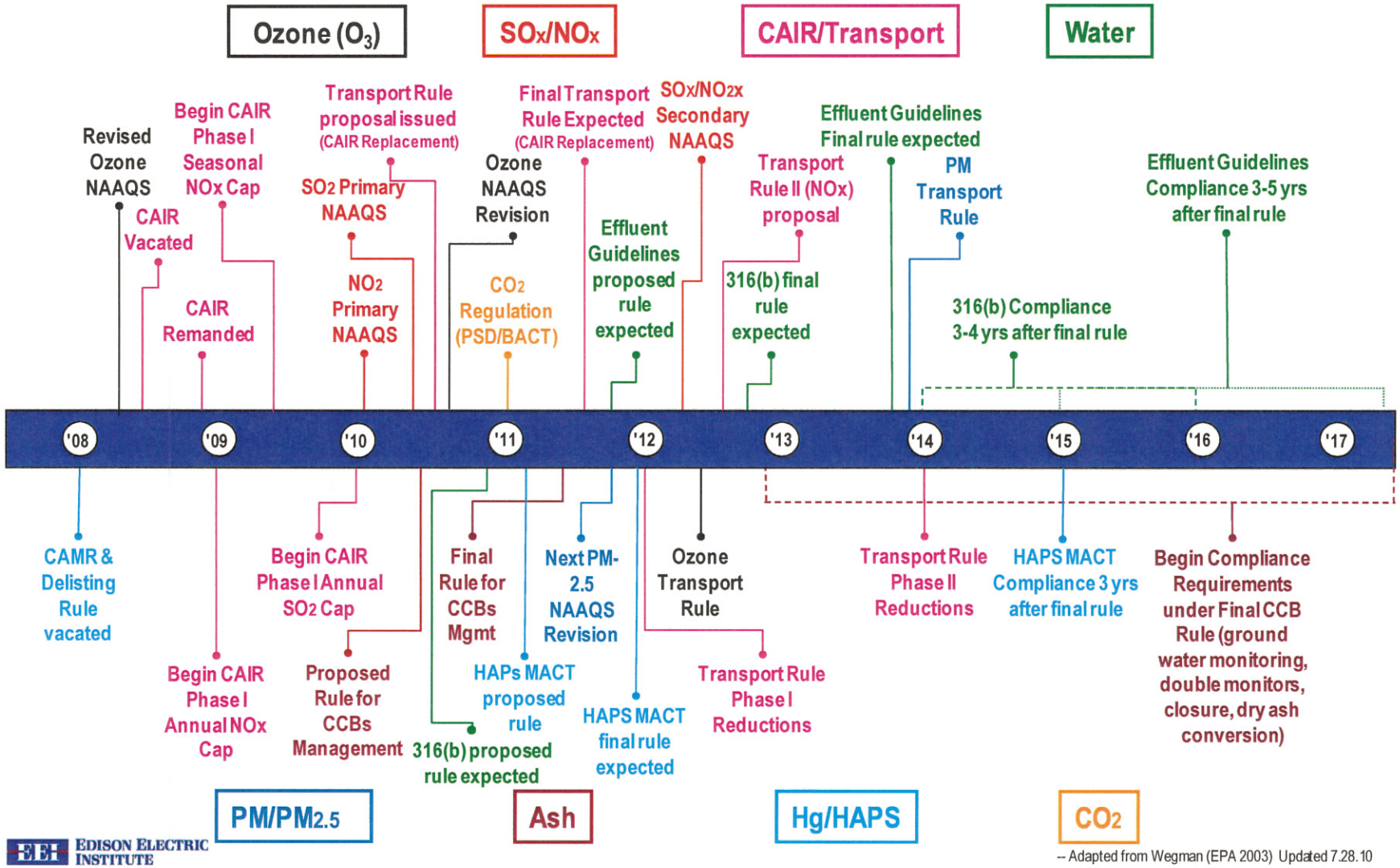
implementation of these programs. This, in turn, will affect the controls, costs and future operational expectations associated with these generating resources.

Conclusion

PacifiCorp has made a significant, long-term commitment to reducing emissions from its coal-fueled facilities and requests that the AQD consider this commitment as a reasonable approach to achieving emission reductions in Wyoming.

November 2, 2010

Attachment 1 Possible Timeline for Environmental Regulatory Requirements for the Utility Industry



EDISON ELECTRIC INSTITUTE

-- Adapted from Wegman (EPA 2003) Updated 7.28.10

Sierra Club/112
Fisher/10

Docket No. UE 374
Exhibit Sierra Club/107
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 107

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

PacifiCorp Comments on WY Regional Haze Plan



August 26, 2013

Submitted via email and electronically to www.regulations.gov

Carl Daly
Director, Air Program
U.S. EPA, Region 8
Mailcode 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202-1129
Email: r8airrulemakings@epa.gov

Re: Docket ID No. EPA-R08-OAR-2012-0026
Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze" (78 Fed. Reg. 34,738 (June 10, 2013)

Dear Mr. Daly:

PacifiCorp submits these comments (including attachments and exhibits) in response to the U.S. Environmental Protection Agency's re-proposed action regarding the Wyoming Regional Haze State Implementation Plan ("RH SIP"). PacifiCorp appreciates the opportunity to offer these comments.

Sincerely,

Micheal G. Dunn
President and Chief Executive Officer
PacifiCorp Energy
1407 W. North Temple
Salt Lake City, Utah 84116

August 26, 2013 Comments
Docket ID No. EPA-R08-OAR-2012-0026

August 13, 2013
PacifiCorp's "Detailed Comments" regarding:
"Approval, Disapproval and Promulgation of State Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze"

PacifiCorp submits these comments concerning EPA's proposed partial approval and partial disapproval of the Wyoming State Implementation Plan for Regional Haze ("Wyoming RH SIP"), as well as EPA's proposed Federal Implementation Plan ("RH FIP") for Wyoming. (*See* "Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze," 78 Fed. Reg. 34,738 (June 10, 2013) (hereinafter referred to sometimes as "RH FIP Action").) The RH FIP focuses primarily on the "Best Available Retrofit Technology" ("BART") determinations for nitrogen oxides ("NO_X"). In addition to these written comments, PacifiCorp has submitted oral comments during public hearings held in Cheyenne, Wyoming on June 24 and July 17, 2013 and in Casper Wyoming on July 26, 2013.

PacifiCorp believes that the Wyoming RH SIP complies with all applicable requirements and should be approved in total by EPA. PacifiCorp also believes that EPA's proposed disapproval of the Wyoming RH SIP, and EPA's proposed adoption of its RH FIP, are flawed because of the following main reasons, as explained more fully below.

*** BART Bootstrap.** EPA claims that Wyoming failed to properly consider two BART factors (cost and modeled visibility improvement) in connection with Wyoming's BART NO_X determinations. As its chosen remedy for these alleged failures, EPA disapproved Wyoming's entire five-factor BART NO_X determinations for five PacifiCorp BART Units, performed its own BART analysis for each unit (leaving out some factors as explained below), and issued its own BART determinations. This is little more than a classic bootstrap maneuver by EPA in order to take over the regional haze program in Wyoming (and other states) that the Clean Air Act ("CAA") intended to be administered by the states. Even if EPA found that Wyoming committed errors with part of its BART determinations, it should have identified the errors, allowed Wyoming to correct them, and instructed Wyoming to reissue its BART determinations.

*** Remaining Useful Life.** PacifiCorp is submitting to EPA new information demonstrating a shorter useful life than EPA assumed in its BART analyses for Naughton Units 1 and 2, and Dave Johnston Unit 3. Accordingly, EPA must redo its BART analyses before taking final action on its proposed RH FIP. This new information, in turn, significantly changes the cost analyses for these units, and demonstrates that EPA's proposed BART controls are not cost-effective. This new information regarding useful lives is contained in Section 6.D of these comments.

In addition, consistent with the Wyoming RH SIP and related requirements, engineering and permitting is underway for the installation of SCR on Jim Bridger Unit 3 in 2015 and Jim Bridger Unit 4 in 2016.

Controls installed to date in compliance with the Wyoming RH SIP and BART permits have reduced annual SO_2 emissions by 56% (72,400 tons per year to 31,500 tons per year) and NO_X emissions by 48% (70,900 tons per year to 36,800 tons per year), with the resulting visibility improvements. When all of the controls required under the Wyoming RH SIP are installed, annual SO_2 emissions will have been reduced to 27,600 tons per year (a 62% reduction) and annual NO_X emissions will have been reduced to 19,200 tons per year (a 73% reduction).

DETAILED COMMENTS

(1) EPA Fails to Afford the Required Deference to Wyoming's Significant Discretion Under Clean Air Act and the Regional Haze Program.

EPA's RH FIP Action failed to afford the required deference to the technical, policy and other discretion granted to Wyoming under the CAA and regional haze program.

Congress added § 169A to the CAA in order to address the "impairment of visibility" in Class I areas that "results from man-made air pollution." This provision of the CAA, in turn, describes separate roles for EPA, the states, and major sources such as PacifiCorp's BART Units.

EPA -- EPA's roles are to create a report, *see* CAA § 169A(a)(2)-(3), create regional haze regulations, *see* CAA § 169A(a)(4), provide guidelines for the states, *see* CAA § 169A(b)(1), and determine whether RH SIPs submitted by the states follow the regulations and guidelines, and contain the required elements. CAA § 110.

States -- The States' roles, which are central to the regional haze program, are intended to be accomplished using substantial discretion which, in turn, requires significant deference from EPA.[2] States are required to submit a RH SIP that contains "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." CAA § 169A(b)(2). States also must "determine[]" BART for "each major stationary source." CAA 169A(b)(2)(A). [3]

[2] Where, as here, the CAA gives decision-making authority to the states, EPA must defer to Wyoming's judgments unless EPA meets it burden of showing that Wyoming acted unreasonably by failing to follow the applicable statutes, regulations and guidelines, or by failing to support with evidence its decision making. See Alaska Dept. of Envtl. Conservation v. EPA, 540 U.S. 461,494 (2004). EPA has made no such showing herein the RH FIP Action. Therefore, Wyoming's BART determinations as contained in the Wyoming RH SIP should stand and EPA should not make final the RH FIP final.

[3] A recent decision by the 10th Circuit Court of Appeals affirmed that "it is undoubtedly true that the statute gives states discretion in balancing the five BART factors…." See

EPA's assertions, that Wyoming did adequately consider "visibility improvement" information in each of its BART determinations, including Wyoming deciding in its discretion the "weight and significance" appropriate for each BART factor at each BART Unit.

3. Wyoming's analyses of SCR costs were not flawed.

EPA inappropriately claimed that "Wyoming's SCR capital costs on a $/kW basis often exceeded real-world industry costs"[21] and then refers to industry studies conducted between 2002 and 2007 that report installed unit capital costs actually incurred by owners broadly ranging "from $79/kW to $316/kW (2010 dollars)." *Id.* EPA also noted "instances" in its proposed RH FIP "in which Wyoming's source-based cost analyses did not follow the methods set forth in the EPA Control Cost Manual." Apart from the irony of EPA failing to follow its own Control Cost Manual as explained in Section 6 below, the information in Tables 4 and 5 shows that EPA is simply incorrect in stating that Wyoming's analyses were flawed and did not reflect real-world industry costs for the units being analyzed. These tables reflect "real-world" costs for the upcoming Jim Bridger Units 3 and 4 SCR projects, which recently were competitively bid for engineering, procurement, and construction contracts to be installed in accordance with the requirements in the Wyoming RH SIP. These real-world costs, in turn, can easily be compared to the costs assessed by Wyoming and by EPA in their BART determinations.

Table 4

Jim Bridger Unit 3 SCR Cost Assessments Comparison (LNB w/ SOFA Baseline) (excludes AFUDC)			
Project Cost Assessment	**Wyoming SIP Cost Basis***	**EPA RH FIP Cost Basis**	**Competitive Market Cost Basis**
Total Capital Costs	$153,000,000	$134,146,938	$176,129,704
Annualized Capital Costs	$14,550,300	$11,049,338	$18,740,200[22]
Annual Operating Costs	$3,370,460	$7,918,786	$2,654,500
Total Annual Cost	**$17,920,760**	**$18,968,124**	**$21,394,700**
Agency Costs versus Real-World Annual Costs (Competitive Market)	**-$3,473,940**	**-$2,426,576**	**-**

* Wyoming SIP SCR cost including AFUDC was $166,500,000 resulting in an Annualized Capital Cost of $15,839,145 and a Total Annual Cost of $19,209,605. The Wyoming SIP information presented above has been adjusted to reflect removal of an estimated $13,500,000 of AFUDC with the corresponding adjustment to Total Annual Cost for comparison purposes.

[21] *See* 78 Fed. Reg. at 34,748

[22] Assumes capital recovery factor of 10.64%; consistent with EPA Control Cost Manual Method and Andover Report cost recovery factor for comparison purposes.

EPA's RH FIP Action also is flawed because it failed to provide sufficient documentation such as vendor estimates or bids to validate its estimates. EPA attempts to justify its approach by stating:[37]

> "In our revised cost analyses, we have followed the *structure* (emphasis added) of the EPA Control Cost Manual, though we have largely used the Integrated Planning Model cost calculations to estimate direct capital costs and operating and maintenance costs."

EPA did not explain what it meant by following the "structure" of the manual, versus simply following the manual. By contrast, PacifiCorp solicited and incorporated vendor estimates into these comments. This new information, which EPA must incorporate into new BART analyses to the extent EPA issues a final RH FIP, validates the state of Wyoming's BART analyses cost of controls estimates. In addition, it further quantifies the inaccuracies in EPA's development and use of purported new information that in no way qualifies as vendor estimates, bids, or any type of site specific vendor information.

B. Second BART Factor - Energy and Non-Air Quality Environmental Impacts of Compliance.

EPA's RH FIP Action is also defective because EPA failed to evaluate the "energy" and "non-air quality environmental" factors for the BART Units. Therefore, even if EPA were correct that Wyoming performed an improper BART analysis (which it is not) EPA's RH FIP Action is based upon an incorrect BART analysis because it fails to take into account this BART factor.

Three types of energy impacts should be considered. These include the energy associated with operating the controls, the energy that must be provided when the unit is removed from service in order to install the controls, and most importantly to the state of Wyoming and its citizens, the energy that must be replaced when the emissions controls prescribed for a given unit are not economically justifiable and result in accelerated unit retirements and replacements.[38]

The latter scenario is of particular concern because the EPA has now proposed SCR controls for PacifiCorp's Naughton Unit 1, Naughton Unit 2 and Dave Johnston Unit 3. Unlike the Wyoming RH SIP, the EPA's RH FIP requires controls that are not expected to be justifiable and would result in accelerated unit retirements and replacements, potential natural gas conversions, and the associated costs and socio-economic impacts of removing major coal-fueled generation resources from service in areas of Wyoming that rely heavily on these facilities.

[37] 78 Fed. Reg. at 34,749

[38] 40 CFR 50 Appendix Y D.IV.h.5

EPA's five-factor analysis must include a thorough analysis of the system-wide energy impacts individual unit compliance requirements will have on the states within which PacifiCorp serves customers, including the impacts to local jobs and state and local economies surrounding the affected facilities. EPA's analysis is incomplete and conclusions are flawed if these significant additional costs are not developed and considered.

EPA's energy impacts assessment should include coordination with state regulators, environmental agencies and elected officials. As a regulated utility, PacifiCorp regularly engages with state regulators, environmental agencies and elected officials to ensure that its resource planning and ultimate compliance approaches align with the interests of customers in the states it serves. These same state bodies and elected officials should be consulted by EPA to ensure that EPA's RH FIP Action is properly assessed in light of the issues described above.

As Powder River Basin Resource Council pointed out in its post-hearing brief filed in April 2013 before the Wyoming Public Service Commission in PacifiCorp's application filing to obtain approval for a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction systems on Jim Bridger Units 3 and 4, "it is evident that considering the cost and risk of these major environmental control projects up front, prior to installation, is a benefit to parties, ratepayers, and the public interest. These projects are significant undertakings – in some cases they are close to the financial equivalent of building new generation sources – and therefore they deserve a high level of scrutiny to ensure that the public's interests, and especially the specific financial interests of PacifiCorp ratepayers, are protected."[39]

PacifiCorp is required to obtain approval of its environmental plans and expenditures; regardless of EPA's position, the utility regulatory commissions are required to find that the installation of emission controls are necessary, used and useful, and the least-cost, risk adjusted alternative to comply with environmental regulations. While it is likely parties will take the position on EPA's proposed action in this docket that stringent controls and emission rates should be installed as quickly as possible without regard to system impacts and cost, their positions in other dockets have been that PacifiCorp should not install emissions controls because doing so "result[ed] in unnecessary capital expenses that were not the least cost alternative."[40]

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[39] See Powder River Basin Resource Council's Post-Hearing Brief in Wyoming Public Service Commission Docket No. 20000-418-EA-12 (RECORD NO. 13314) at: http://edocs.puc.state.or.us/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/FinalDownload/DownloadId-DCE8BAB12B5061CB4017455D76704E32/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/efdocs/HBC/ue246hbc75023.pdf

[40] See Sierra Club's prehearing brief in Oregon Public Utility Commission Docket UE 246 at: http://edocs.puc.state.or.us/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/FinalDownload/DownloadId-DCE8BAB12B5061CB4017455D76704E32/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/efdocs/HBC/ue246hbc75023.pdf

EPA must consider that its proposed RH FIP will "result in significant economic disruption and unemployment" due to accelerated unit retirements and replacements, potential natural gas conversion and removing coal-fired units from service.[41]

C. Third BART Factor - Any Existing Pollution Control Technology in Use at the Source Must be Considered.

In proposing the RH FIP based on its own BART analyses, EPA must evaluate current information, including all significant parameters that have changed since Wyoming completed its BART analyses. Specifically, EPA should take into account that, with the exception of Naughton Unit 3, PacifiCorp has installed and fully implemented the BART controls required under Wyoming's RH SIP. Some of this information was not available, or conditions have substantially changed, since Wyoming completed the Wyoming RH SIP. Table 1 in the "HISTORY OF THE WYOMING RH SIP" section identifies the controls that have been installed at each of PacifiCorp's BART Units in Wyoming.

EPA's RH FIP Action must take into account both the control equipment currently installed and operating on the BART Units as well as each unit's current emissions baseline. It is not appropriate for EPA to continue using a 2001-2003 emissions baseline that does not recognize the controls that have been installed. This is particularly relevant because EPA partially rejected Wyoming RH SIP, and then conducted its own BART analyses in 2013 based on "new information." EPA is well aware of the controls that PacifiCorp has installed in compliance with the Wyoming RH SIP, and in fact, utilized recent NO_X emission rates from PacifiCorp's units that are equipped with BART controls in order to identify appropriate SNCR rates in regard to its RH FIP Action.

To properly assess the visibility and costs associated with adding additional controls, EPA's BART analyses must take into account the control equipment currently operating on these BART Units. Both the annual NO_X emissions used in the cost effectiveness calculations and the hourly NO_X emissions used in the visibility modeling must be corrected to reflect the LNB/OFA controls currently in service on PacifiCorp's BART-eligible units.

D. Fourth BART Factor - The Remaining Useful Life of the Source.

PacifiCorp submitted its BART studies to Wyoming in 2007, and the state completed its BART analyses during 2008. At that time the remaining useful life of all PacifiCorp BART Units was considered to be at least 20 years. Primarily due to EPA's delays in dealing with the Wyoming RH SIP, this assumed twenty-year life span is no longer a valid basis for certain units. EPA now must take into account the current useful life of the units, rather than the useful life assumed under Wyoming's BART analyses completed at

[41] 78 Fed. Reg. at 34,749

a different point in time. Dave Johnston Unit 3's current depreciable life ends in 2027 and the life for Naughton Units 1 and 2 ends in 2029.

As a practical matter, the SCRs required under the RH FIP at Dave Johnston Unit 3 and Naughton Units 1 and 2 could not be installed until shortly before the end of 2018, due to the regulatory processes that apply to PacifiCorp's major investment decisions, as well as the associated permitting and competitive procurement timelines. Attachment 5 provides a general description of such a timeline. At that time, the useful life for Dave Johnston Unit 3 will be nine years, and for Naughton Unit 1 and 2 eleven years. EPA must use these shorter useful lives in its BART analyses. Tables 12 through 14 summarize the cost effectiveness results assuming the proper useful lives of these units, and Attachment 4 to these comments provides the detailed line-by-line cost manual method comparisons.

Table 12

Naughton Unit 1 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment Remaining Depreciable Life Basis (excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,820,054	$3,148,690
Total Indirect Annual Cost	$6,413,089	$12,510,995
Total Annual Cost	$8,233,143	$15,659,686
Annual NO_x Tons Removed	1,109	1,109
Cost Effectiveness ($/ton)	**$7,424**	**$14,121**

Table 13

Naughton Unit 2 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment Remaining Depreciable Life Basis (excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,597,635	$3,474,571
Total Indirect Annual Cost	$7,945,865	$12,435,779
Total Annual Cost	$9,543,500	$15,910,351
Annual NO_x Tons Removed	1,336	1,336
Cost Effectiveness ($/ton)	**$7,143**	**$11,909**

Table 14

Dave Johnston Unit 3 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment Remaining Depreciable Life Basis (excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$2,398,216	$3,884,089
Total Indirect Annual Cost	$11,135,336	$15,611,622
Total Annual Cost	$13,533,552	$19,495,711
Annual NO_x Tons Removed	1,597	1,597
Cost Effectiveness ($/ton)	**$8,474**	**$12,208**

Taking into consideration the remaining useful lives of these particular BART Units clearly demonstrates that EPA's current assessed cost effectiveness conclusions (whether using the Andover Report costs or PacifiCorp's updated information) do not support the installation of SCR on these units because they are not cost effective. To the extent EPA

needs to include firm retirement dates commensurate with the depreciable lives for purposes of finalizing the RH FIP, then PacifiCorp requests that EPA do so.

E. The Fifth BART Factor - The Degree of Visibility Improvement which may Reasonably be Anticipated from the use of BART.

Finally, EPA's RH FIP Action must appropriately consider new information provided by PacifiCorp and others associated with visibility modeling. In comments provided in response to EPA's first proposal, PacifiCorp presented substantial information supporting the need to use improved and updated versions of the computer models used to predict visibility impacts. In addition, PacifiCorp provided substantial information on the effects that the nitrogen oxides to nitrogen dioxide conversion rate and background ammonia concentrations have on modeled visibility impacts. EPA's RH FIP Action is not complete without taking into account this new information about visibility. In particular, given that EPA has re-proposed its RH FIP based on cost and visibility information from certain groups, EPA should analyze and incorporate PacifiCorp's data in the same way.

Computerized air quality modeling plays two key roles in the regional haze program. First, unit-by-unit CALPUFF modeling is conducted to determine which BART-eligible units should be subject to BART[42]. Wyoming determined that a source modeled to impact a Class I area by more than 0.5 deciviews was subject to BART and required to conduct a BART analysis.

The unit-specific CALPUFF modeling results that EPA uses in its RH FIP Action do not provide the degree of visibility improvement that can be reasonably anticipated from the use of BART at a specific unit. Regional models that take into account all emission changes from all emissions sources are used for this purpose. EPA's reliance on miniscule modeled visibility improvements conducted at individual BART Units ignores the fact that (1) such small visibility improvements are not perceptible to the human eye, (2) CALPUFF modeling results are unreliable, imprecise, and over-predictive, especially when older versions of the model are used, and (3) the modeled improvements occur over just a few days per year. In other words, although running the computer models does create a predicted visibility outcome, it does not provide an outcome that qualifies as "reasonably anticipated."

EPA treats the results from computerized visibility modeling as being capable of accurately predicting visibility improvements down to the tenths or hundredths of a deciview (when one deciview is considered what is humanly perceptible). For example, EPA assumes that a difference of 0.1 or 0.2 deciviews between its model results and Wyoming's model results is material. It is not. The reality is that these computer models, including CALPUFF, are relatively imprecise. The inherent problems and limitations of the computerized visibility modeling EPA used here should be considered as part of EPA's BART determinations, but were not. Outlined below are the problems and

[42] 40 CFR Part 51 Appendix Y, III. How to Identify Sources "Subject to BART"

Docket No. UE 374
Exhibit Sierra Club/108
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 108

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Jeremy Fisher

Confidential Rebuttal Testimony of Dana Ralston

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/109
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 109

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Redacted Supplemental Rebuttal Testimony of Cindy A. Crane

Exhibit No. CAC-1CT
Docket UE-152253
Witness: Cindy A. Crane

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET UE-152253

PACIFIC POWER & LIGHT COMPANY

REDACTED SUPPLEMENTAL REBUTTAL TESTIMONY OF CINDY A. CRANE

May 2016

TABLE OF CONTENTS

QUALIFICATIONS 1
PURPOSE AND SUMMARY OF TESTIMONY 2
OCTOBER 2013 MINE PLAN 3
THIRD-PARTY FUEL COSTS 8
TWO-UNIT SCENARIO 11
OTHER ISSUES 13
CONCLUSION 15

ATTACHED EXHIBITS

Confidential Exhibit No. CAC-2C—Corrected Coal Cost Comparison between January 2013 Long-Term Fueling Plan and October 2013 Mine Plan

Confidential Exhibit No. CAC-3C—Analysis of Hypothetical Jim Bridger Two-Unit Scenario

Exhibit No. CAC-4—Pacific Power's Response to Sierra Club Data Request 1.11

Q. Please state your name, business address, and present position.

A. My name is Cindy A. Crane. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. I am the President and Chief Executive Officer of Rocky Mountain Power, a division of PacifiCorp.

Q. Have you previously testified in this proceeding on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. No, but I am adopting the pre-filed rebuttal testimony and exhibits of Mr. Dana Ralston, which have been identified as Exhibit Nos. DR-1CT, 2C, 3C, and 4C.

QUALIFICATIONS

Q. Briefly describe your professional experience.

A. I joined PacifiCorp in 1990. Since then I have served as Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis, Vice President of Strategy and Division Services, and Vice President of Interwest Mining Company and Fuel Resources. My responsibilities in these positions included the management and development of PacifiCorp's 10-year business plan, directing operations of the Energy West Mining and Bridger Coal companies, and coal supply acquisition and fuel management for PacifiCorp's coal-fired generating plants. In October 2014, I was appointed to my present position as President and Chief Executive Officer of Rocky Mountain Power.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before public utility commissions in all states in which PacifiCorp serves customers, including Washington.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your supplemental rebuttal testimony?

A. My testimony responds to the supplemental testimony of Mr. Jeremy B. Twitchell on behalf of Staff of the Washington Utilities and Transportation Commission (Commission) related to the prudence of the Company's decision to install selective catalytic reduction systems (SCRs) on Units 3 and 4 of the Jim Bridger generating plant (Jim Bridger Units 3 and 4). In particular, I respond to Staff's analysis of the coal costs Pacific Power used in its present value revenue requirement differential calculations (PVRR(d)) supporting the decision to install SCRs.

Q. Please summarize your testimony.

A. Pacific Power's decision to install SCRs at Jim Bridger Units 3 and 4 was prudent, and the Company's analysis supporting the decision was based on the best available information at the time the decision was made. Staff accuses the Company of failing to consider increases in coal costs and decreases in natural gas prices when it issued the full notice to proceed (FNTP) on December 1, 2013. Staff bases these accusations on an alleged lack of evidence that these changes were considered, and relies on an analysis of Bridger Coal Company (BCC) coal costs prepared by the Company in fall 2013 as part of its annual budgeting process (the October 2013 mine plan) and selective application of third-party natural gas price forecasts. Staff's accusations are unfounded and untrue.

Mr. Chad A. Teply addresses Staff's assertions that the Company did not consider these changes in December 2013 before issuing the FNTP, and Mr. Rick T. Link addresses the natural gas price forecasts. In this testimony, I address Staff's

assertions about estimated coal costs in fall 2013. Although certain costs related to BCC increased in the October 2013 mine plan, other costs decreased, including decreases in capital expenditures and third-party coal costs. The changes in the October 2013 mine plan were not material and did not warrant an update to the Company's long-term fueling plan (what has been called the January 2013 mine plan, but is referred to in the Company's supplemental rebuttal testimony as the January 2013 long-term fueling plan to clarify the intended purposes of the two different types of plans) or its SCR analysis.

OCTOBER 2013 MINE PLAN

Q. Please describe the Company's October 2013 mine plan.

A. As discussed in Mr. Ralston's rebuttal testimony, the October 2013 mine plan was developed by the Company as part of its annual budgeting process.[1] The plan was prepared to forecast BCC coal costs for a 10-year budget horizon. Although the October 2013 mine plan includes forecasts beyond this 10-year horizon, this information is used only to develop reclamation funding inputs for the 10-year budget horizon. In contrast, the Company prepares long-term fueling plans, such as the January 2013 long-term fueling plan, for use in the integrated resource planning process and in analyses of decisions with long-term impacts to the Company and its customers, such as the decision to install SCRs at Jim Bridger Units 3 and 4. Therefore, the nature of the data provided in the two types of plans is different, and different analytical rigor is applied in developing the long-term data included in the plans.

[1] Ralston, Exh. No. DR-1CT 3:8-4:10.

Q. Is the October 2013 mine plan directly comparable to the January 2013 long-term fueling plan?

A. No. As Mr. Ralston previously testified, the plans are not comparable given the major differences in their purpose, scope, and planning horizons. The Company never relied on the October 2013 mine plan as a long-term fueling forecast for the Jim Bridger plant.

Q. Did the BCC coal costs included in the October 2013 Mine Plan increase by [redacted] over the BCC coal costs included in the January 2013 long-term fueling plan, as Staff testified?[2]

A. No. Because the January 2013 and October 2013 plans are not directly comparable, Staff needed to make several assumptions in conducting its analysis. When errors in these assumptions are corrected, the results show that overall coal costs for the Jim Bridger plant increased by only [redacted] during the 10-year budget horizon covered by the October 2013 mine plan. This amount is consistent with the [redacted] increase reflected in the Company's long-term fueling plan for the Jim Bridger plant used for the 2015 Integrated Resource Plan (IRP) for the 2016-2030 period.[3] If the Company had updated costs by this percentage increase in both the two-unit operating scenario (the natural gas conversion alternative) and four-unit operating scenario (the SCR alternative), the SCR benefits would have decreased by approximately [redacted] over the 10-year budget period, as set forth in Exhibit

[2] Twitchell, Exh. No. JBT-28HCT 18:12-15.
[3] Ralston, Exh. No. DR-1CT 7:16, Exh. No. DR-4C. The long-term fueling costs used in the 2015 IRP were based on the Company's July 22, 2014 BCC mine plan. The Company originally produced a BCC mine plan on July 9, 2014, that it used in its 10-year budget. This plan was updated with only a few changes in the July 22, 2014 mine plan. The long-term fueling plan was finalized in November 2014 after the Company had updated third-party coal costs.

No. CAC-2C. This is a conservative assumption because, as discussed below, the Company's analysis shows that projected cost increases in a two-unit scenario under the October 2013 mine plan would have offset all cost increases in the four-unit scenario.

Q. Before filing its initial or supplemental testimony, was Staff aware that the October 2013 Mine Plan was not directly comparable to the January 2013 long-term fueling plan?

A. Yes. In Mr. Twitchell's initial testimony, he explained that he had reviewed the record from the Company's 2014 Utah rate case to determine how the SCR investments were treated.[4] My testimony in that case explained the differences between the October 2013 mine plan and the January 2013 long-term fueling plan and made clear that they are not directly comparable.[5] Mr. Twitchell's review of the record from the 2014 Utah rate case should have alerted him to the material differences in these two plans. Moreover, Mr. Ralston clearly explained in his rebuttal testimony that these two plans are not directly comparable for the same reasons discussed here.[6]

Q. Please describe the first incorrect assumption made in Staff's new analysis.

A. Staff mistakenly assumes that the long-term data in the October 2013 mine plan is comparable to the long-term data in the January 2013 long-term fueling plan and uses some of this longer-term data from the October 2013 mine plan (data for the period

[4] Twitchell, Exh. No. JBT-1T 62:1-4. Sierra Club also included a copy of my Utah rebuttal testimony as an exhibit to its testimony in this case. Fisher, Exh. No. JIF-8. The Company's 2014 Utah rate case was docket No. 13-035-184.
[5] *See e.g.* Exh. No. JIF-8 5:72-81.
[6] Ralston, Exh. No. DR-1CT 3:8-23.

2023 through 2030).[7] As I explain above, the long-term cost and revenue assumptions included in the October 2013 mine plan were not developed with the same analytical rigor that the Company uses to develop its long-term fueling plans because this data is used solely to determine appropriate contributions to the reclamation sinking fund during the 10-year budget horizon. This is why, as Staff noted, in the October 2013 mine plan the longer-term capital cost data was kept in a different file than the capital cost data for the 10-year budget horizon.[8]

Q. Please describe the second erroneous assumption in Staff's analysis.

A. Staff's analysis includes a modeling error in BCC's "Mine and Equipment Maintenance" cost component in 2028 that inflates coal costs by [redacted] (Company portion, [redacted]). On a net-present-value basis, correcting this error reduces Staff's calculated coal cost increase by approximately [redacted].

Q. What is the impact of correcting the analysis to account for only the 10-year budget horizon reflected in the October 2013 mine plan and correcting Staff's modeling error?

A. The overall increase in coal costs is only [redacted]. Notably, this increase is consistent with the overall increase between the January 2013 and 2015 IRP long-term fueling plans for the Jim Bridger plant, as I note above. The fact that the long-term cost projections in the 2015 IRP are consistent with the 10-year budget but inconsistent with Staff's 2016 to 2030 analysis highlights the underlying problems in Staff's approach.

[7] *See e.g.* Twitchell, Exh. No. JBT-28HCT 18:7-9.
[8] Twitchell, Exh. No. JBT-28HCT 17 n. 21.

Q. Are there any other indicators that Staff's analysis was flawed?

A. Yes. The flaws in Staff's revised analysis should have been apparent simply by examining the overall results. In response testimony, Staff claimed that BCC coal costs increased by [redacted], which resulted in a downward adjustment to the SCR benefits of [redacted].[9] Now, Staff claims that coal costs increased by only [redacted], yet the downward SCR adjustment increased to [redacted].[10]

Q. Staff contends that the Company's continued reliance on the January 2013 long-term fueling plan even after the October 2013 mine plan was developed was unreasonable.[11] How do you respond?

A. I disagree. During the budgeting process in fall 2013, the Company recognized that increases in BCC cash costs would be substantially offset by reduced BCC capital spending and third-party fuel costs. Nothing in the October 2013 mine plan signaled that the January 2013 long-term fueling plan was obsolete.

Q. Staff bolsters its long-term analysis by pointing to coal cost increases reported in the Company's 2014 Washington rate case.[12] Is Staff's reliance on rate case coal costs appropriate here?

A. No. Staff claims that if the October 2013 mine plan "created cost increases that were sufficiently known and measurable to support a rate increase, then those costs increases were sufficiently known and measurable to be included in the Company's planning." But as Staff acknowledges, the coal costs included in the Company's rate

[9] Twitchell, Exh. No. JBT-1T 34:12-14; 9, Figure 1.
[10] Twitchell, Exh. No. JBT-28HCT 18:12-15; 19:20-21.
[11] Twitchell, Exh. No. JBT-28HCT 6:12-19.
[12] Twitchell, Exh. No. JBT-28HCT 7:8-12; 8:1-14; 10:17 – 11:20. The Company's 2014 Washington rate case was Docket UE-140762.

case filings reflect costs expected during the rate year.[13] The analysis used to develop test-period coal costs for a general rate case is fundamentally different from the analysis required to develop long-term fuel plans for a generating plant. Because the October 2013 mine plan updated BCC coal costs for the 10-year budget horizon (a relatively short-term period), the Company reasonably relied on the October 2013 mine plan to establish short-term rates. The fact that the mine plan was used to determine short-term costs does not mean that it is appropriate as a long-term forecast or as a comprehensive life-of-plant fueling plan for the Jim Bridger plant.

THIRD-PARTY FUEL COSTS

Q. Staff acknowledges that the October 2013 Mine Plan did not update third-party coal costs.[14] Staff therefore relied on the third-party coal increases from the 2014 Washington rate case to forecast the change in third-party coal costs over the 2016 to 2030 study period.[15] Is this a valid way to forecast third-party coal costs?

A. No. Staff's reliance on the 2014 Washington rate case produces two fundamental errors in its analysis of third-party coal costs. First, Staff unreasonably assumes an [redacted] annual cost increase for third-party coal. Second, Staff unreasonably assumes that the production ratio between BCC and third-party suppliers reflected in the Company's direct filing in its 2014 Washington rate case will remain constant through 2030. Both of these assumptions are incorrect.

[13] Twitchell, Exh. No. JBT-28HCT 11: 16-17.
[14] Twitchell, Exh. No. JBT-28HCT 10:5-9.
[15] Twitchell, Exh. No. JBT-28HCT 18:17 – 19: 8.

Q. How did Staff calculate its assumed increase for third-party coal costs?

A. Staff compared the costs of Black Butte coal in the Company's 2013 Washington rate case[16] to the costs of Black Butte coal in the Company's 2014 Washington rate case. Because costs increased by [redacted] between the 2013 and 2014 cases, Staff assumed that costs would continue to increase at [redacted] annually until 2030.[17]

Q. What is wrong with this assumption?

A. First, there were 15 months between the 2013 and 2014 net power cost test years. Therefore, the annual change is only [redacted] not [redacted]. Second, it is unreasonable to assume that third-party coal costs would increase at the same percentage annually through 2030 based on consideration of changes over only one 15-month period. The third-party cost increase between the 2013 and 2014 case represented a price change between two test periods based on contract terms that were expiring in 2015. There is absolutely no basis to assume that the increases in those cases reflect long-term expectations.

Q. How would you correct Staff's assumed third-party cost increase?

A. Based on what the Company knew in fall 2013, during the 10-year budget horizon third-party coal costs were expected to increase by roughly [redacted] annually. When factored into the overall plant fueling costs, third-party costs inclusive of coal inventory changes known in fall 2013 actually *decrease* by [redacted] relative to the third-party costs assumed in the SCR analysis. This decrease further offsets the modest increase in BCC costs reported in the October 2013 mine plan's 10-year budget horizon.

[16] *Wash. Utils. & Transp. Comm'n v. PacifiCorp,* Docket UE-130043.
[17] Twitchell, Exh. No. JBT-28HCT 18:18-22.

Q. Are there any other deficiencies in Staff's analysis?

A. Yes. The Company's direct testimony in the 2014 Washington rate case was filed in May 2014, well after the period of time that Staff concedes is relevant to the prudence determination in this case. Staff claims that it is improper to reference the long-term fueling plan used in the 2015 IRP to validate the absence of major cost increases in the October 2013 mine plan. But Staff attempts to do the same thing by referencing Company testimony filed in May 2014. The testimony on which Staff relies, however, is irrelevant to the long-term coal cost increases at issue in this case.

Q. What is the second error in Staff's analysis?

A. Staff incorrectly assumes that the ratio between BCC and third-party coal reflected in a single year is indicative of the ratio from 2016 through 2030.[18]

Q. How did Staff determine the amount of coal provided by BCC and third-parties from 2016 through 2030?

A. To determine the ratio between BCC and third-party coal over a 17-year period, Staff relies on testimony from the Company's 2014 Washington rate case. In that case, the Company's direct testimony projected that BCC would provide roughly 85 percent of the plant's total coal, with third-party mines providing the remaining 15 percent. The Company's projection in the 2014 rate case, however, was based on expected coal deliveries *during a single year*—April 2015 through March 2016. Staff is incorrect to assume that BCC would provide 85 percent of the plant's total coal until 2030 based on a single year of data.

[18] Twitchell, Exh. No. JBT-28HCT 18:17 – 19:8.

The flaw in Staff's assumption is evident from the record in the 2014 rate case. By the time the Company filed its rebuttal testimony in that case, the proportion of BCC coal decreased to approximately 70 percent of the plant's total coal requirement.[19] This fact undermines Staff's claim that the October 2013 mine plan increased the Company's exposure to market risk because of greater reliance on third-party coal.[20]

TWO-UNIT SCENARIO

Q. Staff contends that if the Company had performed a two-unit scenario analysis in October 2013 it would have shown that coal costs in a two-unit scenario would have decreased, making gas conversion even more attractive.[21] Is Staff's conclusion sound?

A. No. Staff's analysis again relies on incorrect assumptions. First, Staff claims that the surface mine is subject to economies of scale, while implying that the underground mine is not.[22] On the contrary, both the surface and underground mine are subject to economies of scale—as production decreases in either operation the per-unit cost increases. Under a two-unit scenario, production would decrease.

Q. Does Staff's analysis include any other incorrect assumptions?

A. Yes. Staff reasons that under a two-unit scenario based on the October 2013 Mine Plan, the surface mine would continue to operate, which would avoid accelerated reclamation and result in lower costs relative to the two-unit scenario based on the

[19] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-140762, Exh. No. CAC-1CT 6:13-16.
[20] Twitchell, Exh. No. JBT-28HCT 12:10-18.
[21] Twitchell, Exh. No. JBT-28HCT 24:10-13.
[22] Twitchell, Exh. No. JBT-28HCT 23:19 – 24:13.

January 2013 long-term fueling plan.[23] Additionally, Staff states that availability of underground coal through 2023 in the October 2013 mine plan would also lower costs.[24] Relying on these assumptions, Staff concludes that a two-unit scenario based on the October 2013 mine plan would have lower costs than the January 2013 two-unit scenario.

Q. If the Company had developed a two-unit scenario based on the October 2013 Mine Plan, would the costs be less than the January 2013 two-unit scenario?

A. No. Both the January 2013 two-unit scenario and the October 2013 mine plan consider varying levels of underground coal production through 2023. The primary difference between the January 2013 two-unit scenario and a two-unit scenario based on the October 2013 mine plan is that surface mine closure occurs in 2018 in the January 2013 two-unit scenario and the surface mine continues to operate in the October 2013 mine plan.

To quantify the impact of this change using information available in fall 2013, the Company compared BCC surface mine cash costs, BCC surface mine capital costs expressed on a revenue requirement basis, and external coal prices to costs in the January 2013 two-unit scenario. Based on this analysis, the Company estimates that two-unit scenario coal costs would have increased by approximately [redacted] during [redacted] based on changes in the October 2013 mine plan. This is primarily due to higher costs at the surface mine. The cost increases in the two-unit scenario would have entirely offset the cost increases in the four-unit scenario in the Company's PVRR(d) analysis—making the SCR investment become more favorable

[23] Twitchell, Exh. No. JBT-28HCT 23:10-18.
[24] Twitchell, Exh. No. JBT-28HCT 24:8-10.

based on the October 2013 Mine Plan. My analysis is shown in Exhibit No. CAC-3C.

Q. How does this analysis relate to the Company's previous testimony responding to Sierra Club's use of the January 2013 four-unit scenario as a proxy for the October 2013 two-unit scenario?

A. In rebuttal testimony, Mr. Ralston testified that it was reasonable to assume that the two-unit costs increased at the same percentage as the four-unit costs in the Company's 2015 IRP fueling plan. This responded to Sierra Club's claim that the two-unit costs in the 2015 IRP fueling plan would have actually decreased to the level of four-unit costs in January 2013. The Company's updated analysis indicates that its previous estimate of two-unit coal costs in the 2015 IRP fueling plan, which projected only a [redacted] increase, was conservative.[25]

Q. Why didn't the Company update its two-unit scenario coal costs in fall 2013?

A. As I discuss above, nothing in the October 2013 mine plan raised concerns that the January 2013 long-term fueling plan was obsolete or that costs in the two-unit scenario were decreasing relative to costs in the four-unit scenario. Under these circumstances, updating the two-unit scenario was unnecessary.

OTHER ISSUES

Q. Staff testifies that they do not understand why the Company conducted analysis in its rebuttal testimony based on the Company's 2015 IRP fueling plan.[26] Why did the Company include that analysis in its rebuttal testimony?

A. As explained clearly in Mr. Ralston's rebuttal testimony, the Company was responding to Sierra Club's comparison of coal costs between the January 2013 long-

[25] Ralston, Exh. No. DR-1CT 12:10-14.
[26] Twitchell, Exh. No. JBT-28HCT 8:16 – 9:4.

term fueling plan and the long-term fueling plan used in the 2015 IRP.[27]

Q. Staff claims that the long-term fueling plan used in the 2015 IRP is "not relevant in evaluating the prudence of the Company's decision" because "it was prepared several months after Pacific Power issued the full notice to proceed (FNTP) with SCR installation at Bridger."[28] Do you agree?

A. Yes, in part. The Company generally agrees that the prudence standard examines whether a utility's decision was reasonable based on the information it knew or should have known at the time the decision was made. The data used in the 2015 IRP is therefore not relevant to the prudence of the Company's decision to install SCRs at Jim Bridger Units 3 and 4 because the data was developed after the Company made the decision in May 2013 and after it issued the FNTP on December 1, 2013. But in this case, Staff argues that "rising coal costs and falling natural gas costs"[29] between January 2013 and October 2013 demonstrate "obvious trends" that the Company willfully ignored before issuing the FNTP.[30] The analysis of the SCR investments using the 2015 IRP data is therefore relevant to rebut this argument and to verify that there was no significant long-term trend of increasing coal costs.

[27] Ralston, Exh. No. DR-1CT 6:4-9; 7:14 – 10:16.
[28] Twitchell, Exh. No. JBT-28HCT 8:17-19.
[29] Twitchell, Exh. No. JBT-28HCT 33:5-6.
[30] Twitchell, Exh. No. JBT-28HCT 31:18-19.

Q. One of the corrections Staff made in its supplemental testimony is to exclude non-cash operating costs (*i.e.*, depletion, depreciation, and amortization) from its analysis. While acknowledging its previous error, Staff faults the Company for failing to explain that non-cash operating costs were excluded from the SCR analysis.[31] How do you respond to Staff's allegation?

A. Staff's criticism of the Company is unwarranted. On January 20, 2016, Staff received the Company's response to Sierra Club's Data Request No. 11. That request referenced the Company's cash coal costs set forth in Exhibit No. RTL-3C and asked the Company to: "Identify, separately, the elements of Bridger Coal Company's costs which are specifically included and excluded in cash costs." The Company's response clearly indicated that amortization, depreciation, and depletion are excluded from the cash costs used in the Company's SCR analysis. This data response is attached as Exhibit No. CAC-4. Staff had this information well before filing its rebuttal testimony. In addition, my Utah testimony that Mr. Twitchell reviewed before filing his initial testimony,[32] described in detail how the Company removed the non-cash operating costs from its SCR analysis.[33]

CONCLUSION

Q. What is your recommendation to the Commission?

A. The Commission should conclude that the Company's SCR analysis was robust and its decision to install SCR systems on Jim Bridger Units 3 and 4 was prudent. The October 2013 mine plan showed increased operating cash costs, but those increasing

[31] Twitchell, Exh. No. JBT-28HCT 15:16 – 16:3.
[32] Twitchell, Exh. No. JBT-1T 62:1-4.
[33] Fisher, Exh. No. JIF-8 6:107 – 7:116.

costs were substantially offset by decreased capital and third-party costs, and by cost increases in the two-unit scenario. This shows that changes in coal costs during the period the SCR analysis was under review were adequately considered before the FNTP was issued, as demonstrated by the Company in its rebuttal testimony.

Q. Does this conclude your supplemental rebuttal testimony?

A. Yes.

Docket No. UE 374
Exhibit Sierra Club/110
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 110

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

PacifiCorp Response to Sierra Club Data Request 4.9

13-035-184/Rocky Mountain Power
April 15, 2014
Sierra Club Data Request 4.9

Sierra Club Data Request 4.9

See the Direct Testimony of Cindy Crane 404-414.

(a) Provide an up-to-date map of the Bridger Mine complex (surface and underground), including expected development dates for future areas or panels. It is expected that this map will be similar to the map provided in discovery in the Bridger CPCN docket? (Wyoming Docket No. 20000-418-EA-12).

(b) To what extent is the Bridger Coal Company (BCC) aware of mine ash content in advance of mining operations? Has BCC identified any other regions of the underground mine that might include higher-than acceptable ash levels?

Response to Sierra Club Data Request 4.9

(a) Please See Confidential Attachment Sierra Club 4.9a.

(b) As the underground mine's geology is complex and varying, Bridger Coal Company conducts an aggressive drilling program. Drilling allows Bridger Coal personnel to determine seam thickness, geologic faults, adverse quality and appropriate extraction points. In most of Bridger Coal's previous longwall panels, Bridger Coal has encountered pockets of high ash coal due to narrowing seam thickness. However, usually the mine can advance through these high ash areas by blending with lower ash coal. As a result of additional drilling in March/April of 2013, Bridger Coal personnel were able to conclude that the majority of the coal in the 12th right longwall contained elevated ash levels far in excess of quality targets resulting in the bypass of the 12th right panel.

While Bridger Coal will continue to encounter areas of elevated ash, Bridger Coal's drilling program allows the geologists and engineers to refine the underground mine plan through its development of the mains, longwall set-up and extraction points.

Docket No. UE 374
Exhibit Sierra Club/111
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 111

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Hearing Transcript of Ms. Cindy Crane

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT SELECTIVE CATALYTIC REDUCTION SYSTEMS ON JIM BRIDGER UNITS 3 AND 4 LOCATED NEAR POINT OF ROCKS, WYOMING	DOCKET NO. 20000-418-EA-12 (RECORD NO. 13314) CONFIDENTIAL

TRANSCRIPT OF HEARING PROCEEDINGS

Volume I

PURSUANT TO NOTICE duly given to all parties in interest, this matter came on for hearing on the 26th day of March, 2013, at the hour of 8:30 a.m., in the Commission Hearing Room, 2515 Warren Avenue, Suite 300, Cheyenne, Wyoming, before the Public Service Commission, Steve Mink, Assistant Secretary and Counsel, presiding; with Chairman Alan B. Minier and Commissioner William F. Russell also in attendance. Also present were Lori Brand, Assistant Secretary and Counsel; Dave Walker, Michelle Bohanan, Brittney Brinkmeier, Laura Yetter and Perry McCollom, technical advisors to the Commission.

(Witness sworn.)

MR. MINK: Please be seated.

CINDY A. CRANE,

called for examination by the Applicant, being first duly sworn, on her oath testified as follows:

DIRECT EXAMINATION

Q. (BY MR. HICKEY) Good afternoon.

A. Good afternoon.

Q. For the record, could you please state your name and your business address.

A. Okay. My name is Cindy Crane. My business address is 1407 West North Temple, Salt Lake City, Utah.

Q. And by whom are you employed, Ms. Crane?

A. I am the vice president of Interwest Mining Company as well as PacifiCorp's fuel resources department.

Q. And could you please summarize the duties and responsibilities that you hold in that position for PacifiCorp.

A. Yes, I can. I have responsibility for the management of PacifiCorp's subsidiary coal mining operations as well as for PacifiCorp's coal fueling for the entire coal generation fleet. So I procure the fuel as well as the mining aspects of the fuel that we mine as well as the transportation responsibilities for delivery to the plants.

Q. And have you had an opportunity to file rebuttal testimony in this docket that's now received in evidence as Rocky Mountain Power Exhibit 3?

A. Yes, I have.

Q. And do you have any additions or corrections to that testimony?

A. No, I do not.

Q. Have you had an opportunity to prepare a summary of your testimony?

A. Yes, I have.

Q. Would you please share it with the Commission and the parties.

A. Certainly. Thank you.

Mr. Chairman, Commissioner Russell and your advisors. I'm here today to address the coal supply update that was made as part of the rebuttal filing as well as to respond to coal-supply-related issues that were raised by intervenors in this case.

Regarding the coal supply update specifically, as part of the Bridger mines coal supply agreement, the mine has a contractual obligation with Idaho Power and PacifiCorp which requires them to perform updated life of mine plans, including reclamation plans, every three years. The last detailed update of these plans was completed in 2009.

So in the original filing in this case, the company utilized the 2011 business plan from the Bridger mine. Unfortunately, the business plan did not have updated reclamation trust fund contribution rates included in it.

Subsequent to this initial filing or the original filing in this case, the mine was able to complete all of its regularly scheduled updated life of mine planning. So with the updated and detailed life of mine planning completed, the company was then able to utilize that more current information in the rebuttal filing to ensure that we had the absolute most current information available in this proceeding for the analysis and the decision-making.

My rebuttal testimony in this proceeding explains what the changes in the fuel costs from the original filing to the rebuttal were and what drove those between the two filings.

In addition, I directly respond in my testimony to issues raised by Sierra Club witness Dr. Fisher. The first issue that Dr. Fisher raised in his direct testimony was a question of whether it was appropriate for the company to include in the Bridger surface mine the shutdown reclamation costs in the gas conversion cases, which Dr. Fisher was claiming would inappropriately burden the decision in the gas conversion cases over the SCR

installation cases.

Following extensive interrogatories as well as rebuttal testimony in this proceeding by myself and other parties, Dr. Fisher in his cross testimony does now agree that it is appropriate for the company to include those mine reclamation costs in its analysis in the CPCN proceeding.

Secondly, Dr. Fisher contends in his direct testimony that the company could take the Bridger surface mine's coal and transport it to other company power plants, thereby avoiding the shutdown reclamation costs that are included in the gas conversion cases.

Dr. Fisher in his own direct testimony admits that he cannot definitively support that contention. My rebuttal testimony in this proceeding points out that in Dr. Fisher's analysis that he has in his testimony, he has failed to include any mine capital in that analysis and he is only relying on cash operating costs.

Specifically on the company-owned and operated plants that Dr. Fisher references to believe that we could ship this coal to, he fails to take into consideration that those plants do not have any rail lines or even any unloading facilities in order to receive the coal being brought in. In fact, he cites two of those plants being our Utah plants when, in fact, today those Utah plants

receive 100 percent of their coal either by conveyor belt directly from the mine or by truck.

He also failed to recognize that in our Utah facilities for our plants for the coal supply that we have long-term coal supply agreement commitments which would have significant liquidated damages should the company not meet the minimum requirements under those contracts.

Dr. Fisher also contends that we could take some of this coal to two of our joint-owned power plants that are in Colorado, which we are minority owners at these facilities. But, in fact, in both of those plants, they also have long-term coal supply agreements in place, which would result in significant liquidated damages.

In addition to that, the company does not even have the authority as a minority owner in those facilities to independently make a decision to bring in a different coal supply source.

Lastly, Dr. Fisher contends in his direct testimony that the company could sell the Bridger surface mine coal to others. Dr. Fisher fails to take into consideration that there is already an oversupply, an oversupply situation in the southwest Wyoming coal market area and that, with the upcoming refueling of the company's Naughton Unit 3, the imbalance will even -- will worsen further in that supply area and is likely to cause the

shutdown of at least one of the currently operating mining operations in that coal basin.

He also disregards that the Bridger surface mine's higher overburden cost structure, so higher strip ratios since it's a surface operation, as well as its lower heat content and its higher ash constituency in the coal quality relative to other coals, it will -- places the Bridger surface coal at a significant disadvantage, as well as that the mine does not have any infrastructure facilities in order to load coal so that it can be transported away.

In conclusion, the company operates in all of the western coal markets in order to ensure that we have a portfolio supply to fuel our entire fleet, and we are very much aware of the supply and demand dynamics in these coal basins as well as the coal quality characteristics which determine whether there are markets that exist for specific coals or not.

In addition, the company has been very diligent in its mine planning to ensure that we have included in the analysis in this proceeding the absolute most current detailed mine planning data available for the decision relating to the SCR installations.

That's the conclusion I my summary. Thank you.

MR. HICKEY: Mr. Mink, Ms. Crane is

available for examination by the Commission and parties.

MR. MINK: Thank you.

Mr. Pomeroy.

MR. POMEROY: I have no questions of this witness.

MR. MINK: Mr. Ritchie.

MR. RITCHIE: Yes. A few questions.

CROSS-EXAMINATION

Q. (BY MR. RITCHIE) Good afternoon, Ms. Crane. How are you?

A. Good afternoon. I'm great, thanks.

Q. Travis Ritchie with the Sierra Club.

A. Yes.

Q. Miss Crane, I'd like to start with the statement that I believe you made in your opening summary, and I didn't quite get this right, but please correct me. I believe you said at one point that subsequent to discovery Dr. Fisher now agrees that reclamation costs are appropriate in the CPCN proceeding?

A. Yes. In his own testimony, in his cross testimony -- let me get it for you here -- on page 9 of his cross testimony, he does say, "Since the Bridger coal company is a regulated rate base entity of PacifiCorp, the company fully expects to recover the entity's costs either as a fuel expense or in higher capital costs passed through

to ratepayers via future rate cases. The company makes the appropriate assumption in this case that if the choice to retire or retrofit the Jim Bridger plant incurs a change in planning," which is specifically what occurs to the Bridger surface mine, "those costs should be subject to analysis within the CPCN."

Q. So thank you. And that is the portion of Dr. Fisher's testimony that I was hoping I was going to direct you to if you hadn't already had it ready. So thank you.

But you did state that he conditions that assumption on the clause "if the choice to retire or retrofit the Jim Bridger plant incurs a change in planning"?

A. That is correct.

Q. So you agree that any agreement in Dr. Fisher's testimony is conditioned on that being the case?

A. That's what he states.

Q. Thank you. I just wanted to make that clear.

A. Yes.

Q. So, Ms. Crane, if I could direct you to page 13 of your rebuttal testimony, please.

A. Certainly. Okay.

Q. And the question at line 7 asks if the Bridger surface mine can operate at a reduced level in the two-unit

scenario. When you say a two-unit scenario, I'm assuming you're talking about shutting down two of the power plant operating units; is that correct?

A. That is correct, 50 percent of the level that it's currently operating at today.

Q. So your testimony is that the surface mine would shut down if only two Jim Bridger generating units are operating. Sorry. That was answered. I can move on unless you disagree with me.

Does the mine plan assume that the surface mine would also shut down if only three of the four Jim Bridger units are operating?

A. Yes, it would.

Q. Does it matter which units are shut down?

A. I don't believe so.

Q. So if it was the case that Jim Bridger Units 1 or 2 or both 1 and 2 shut down, then you would similarly expect the Bridger surface mine to shut down?

A. If the other two units had not previously been shut down. There would be a subsequent effect on the Bridger surface mine if that were an outcome of another proceeding.

Q. So to be clear, if 3 and 4 continue to operate but five years from now 1 and 2 either did a gas conversion or shut down, stopped using coal, that you would similarly

expect the Bridger mine remediation costs to be incurred similar to this two-unit scenario that you identified in your testimony?

A. Yes, we believe you would have the same volume loss effect on the mine.

Q. Now, I believe you also stated in your testimony that, compared to the market, Bridger coal is at a significant disadvantage; is that correct?

A. That is correct.

Q. And that's partly due to some of the costs of the overburden and the strip ratios; is that correct?

A. That's correct. It's a high strip ratio mine.

Q. And are those costs increasing?

A. Depending on which pits get mined, they will.

Q. At some point does the cost of the Bridger coal mine exceed the cost of the coal that's available on the market?

A. There's the potential, but that is factored into our analysis in our long-term fueling as we look at that.

Q. But is it fair to say that if the costs of Bridger coal did exceed the costs that were available to the company on the market, would you expect to shut the surface mine and get coal from the market instead?

A. We would certainly look at what the alternatives to manage the best lowest cost portfolio would be.

Q. But to be clear in this proceeding, the shutdown, the remediation costs, the accelerated remediation cost that you identified in the two-unit coal scenario, those costs have been attributed to the gas conversion scenario in the comparison for this proceeding; is that correct?

A. That's correct because the gas conversion scenarios are causing the drop in the volume, and thus, the shutdown of the Bridger surface operation.

Q. And so that assumes that in the gas conversion scenario that Units 1 and 2 are still operating?

A. It assumes we maintain a 50 -- a 50 percent volume from where we're at today.

Q. Through the timeline of the remediation plan. And similarly, that assumes that you continue to use Bridger coal as opposed to going to the market.

A. Yes. We use the Bridger underground coal.

Q. I'll move on a little bit, Miss Crane. I'd like to briefly address an issue that came up in the Utah docket but I don't think was addressed as directly here.

Is it correct that the mining plan for the two-or three-nit Bridger mine scenario assumes that remediation expenses would begin five years prior to the scheduled 2018 mine closure?

A. Subject to check on the five years, they do begin prior to the shutdown date, and that's because the mining

surface drag lines stop mining, and we move to the more economic low-cost high-wall mining, and therefore, those drag lines immediately go into the remediation activities.

Q. And the remediation activities in that scenario continue for a total of nine years; is that correct?

A. Subject to check, I believe that's correct.

Q. And conversely, in your analysis of the four-unit scenario where four units continue to operate, the remediation expenses begin only two years prior to the expected mine closure of 2037; is that correct?

A. I think in actuality, Mr. Ritchie, we have remediation expenses in some volumes as we go. So, you know, it's all about magnitude, but the bulk of the remediation costs for the final shutdown costs do occur at the tail end of the life of the mine, which in the four-unit scenario is nearer to the 2037 date. So I believe they start significantly later, and that's driven because the drag lines are both operating full time, 7 by 24 producing coal through that entire period, and therefore, we are still actively mining in those pits. Therefore, they are not at a point in their life to be reclaimed.

Q. And just to be clear to finish up that end that pushed out the 2037 scenario, the four-unit scenario, the remediation expenses in that scenario the plan calls for a

12-year period for the bulk of those remediation expenses; is that correct?

A. Subject to check.

Q. Subject to check. Okay. Do you know -- in the company's updated analysis, do you know the total net present value impact that the surface mine remediation case had on the company's updated analysis?

A. It would be a confidential number for starters.

Q. Well, before I ask what the number is, do you know what it is?

A. What I can provide you is that I know what the change in the fuel cost update was from the original filing to the rebuttal filing.

Q. But as far as the number, I believe Mr. Teply had stated in confidential as well there's a number that was kind of the final conclusion of what the present-value revenue requirement differential was in this case, and what I'm asking for, because I don't know because I didn't see it in the testimony, is what is the Bridger mine's -- the two-unit scenario Bridger mine's contribution to that total number?

A. I would need to chat with Mr. Link being's he's the one that does the holistic modeling in the case. We provided some inputs as it pertains to fuel, but he does the present-value modeling himself.

MR. RITCHIE: Fair enough, Miss Crane, thank you. I have no further questions.

MR. MINK: Miss Anderson.

MS. ANDERSON: I do not have any questions. Thank you.

MR. MINK: Mr. Williams.

MR. WILLIAMS: I have no questions. Thank you.

MR. MINK: Mr. McCollom, do you have questions?

MR. McCOLLOM: No questions. Thank you.

MR. MINK: Miss Brinkmeier?

MS. BRINKMEIER: No questions.

MS. BOHANAN: No questions.

MS. YETTER: No questions.

COMMISSIONER RUSSELL: No questions.

CHAIRMAN MINIER: No questions.

MR. HICKEY: Mr. Mink, I'd ask on behalf of Miss Crane that she be excused from the balance of the proceeding. She has some business to attend to in Salt Lake tomorrow.

MR. MINK: As you wish.

MR. HICKEY: If that's the pleasure of the Commission, I know she would appreciate being excused from the balance of the hearing.

Docket No. UE 374
Exhibit Sierra Club/112
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 112

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

"Attach Sierra Club 3.27" in Docket No. LC 70

Scenario	Plant Closure Dates Units 1 2 3 4	Bridger Coal Assumptions	Black Butte Assumptions	Powder River Basin Assumptions
P-01	37,37,37,37	Opt D Mine Plan - Underground Mine 2022 Closure, Surface Mine 2037 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-02	37,37,37,37	Opt D Mine Plan - Underground Mine 2022 Closure, Surface Mine 2037 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-03	28,32,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-04	22,22,37,37	Opt E Mine Plan - Underground Mine 2022 Closure, Surface Mine 2022 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-06	22,32,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-07	22,28,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-08	28,32,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-09	28,32,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-10	22,22,37,37	Opt E Mine Plan - Underground Mine 2022 Closure, Surface Mine 2022 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-11	28,32,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-12	22,28,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-13	37,37,37,37	Opt D Mine Plan - Underground Mine 2022 Closure, Surface Mine 2037 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-14	22,22,22,22	Opt E Mine Plan - Underground Mine 2022 Closure, Surface Mine 2022 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A

P-15	26,25,23,24	Opt E Mine Plan - Underground Mine 2022 Closure, Surface Mine 2022 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-28	28,32,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-30	28,32,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-31	28,32,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-32	22,28,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-33	22,22,37,37	Opt E Mine Plan - Underground Mine 2022 Closure, Surface Mine 2022 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-34	22,22,37,37	Opt E Mine Plan - Underground Mine 2022 Closure, Surface Mine 2022 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-35	28,32,22,22	Opt E Mine Plan - Underground Mine 2022 Closure, Surface Mine 2022 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-36F2	25,25,25,25	2025 Alt Mine Plan - Underground Mine 2022 Closure, Surface Mine 2025 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-45	23,28,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-46	28, 32, 25, 25	2025 Alt Mine Plan - Underground Mine 2022 Closure, Surface Mine 2025 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-46FJ23	28,32,23,23	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-47	23,28,35,35	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-48	23,28,33,33	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A

P-53	25,25,28,32	2025 Alt Mine Plan - Underground Mine 2022 Closure, Surface Mine 2025 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-53FJ23	23,23,28,32	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	PRB Coal Prices are based on third party forecasted prices. Rail escalated quarterly based on third party forecast.
P-54	28,24,37,37	Opt F Mine Plan - Underground Mine 2022 Closure, Surface Mine 2028 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-70	22,37,37,37	Opt D Mine Plan - Underground Mine 2022 Closure, Surface Mine 2037 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-71	37,37,37,37	Opt D Mine Plan - Underground Mine 2022 Closure, Surface Mine 2037 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-72	37,37,37,37	Opt D Mine Plan - Underground Mine 2022 Closure, Surface Mine 2037 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-73	37,37,37,37	Opt D Mine Plan - Underground Mine 2022 Closure, Surface Mine 2037 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A
P-74	37,37,37,37	Opt D Mine Plan - Underground Mine 2022 Closure, Surface Mine 2037 Closure.	Black Butte Contract Pricing 2018 - 2021, 2022+ pricing escalated annually and adjusted on volume changes. Rail escalated quarterly based on third party forecast.	N/A

Docket No. UE 374
Exhibit Sierra Club/113
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 113

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Life beneath the earth in Wyoming's only underground coal mine

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Life beneath the earth in Wyo's only underground coal mine



September 3, 2019 by Andrew Graham — Leave a Comment

POINT OF ROCKS — In the Bridger Underground Coal Mine, the roof, walls and ground underfoot are composed of the black rock. In a tunnel 700 feet under the earth, mine superintendent Bob Fox turns off the headlights of a specially modified pickup and the darkness becomes total.

Down here, miners are identifiable by the beam of their headlamps. In the chamber that marks the end of the mine and the locus of its activity, the helmet-mounted lights bob and stab as the longwall miner, a machine that peels the face of the coal seam, rips off chunks of coal with two circular saws.

Total darkness is just a light switch away and the earth above presses down around and behind the miners as the longwall miner grinds across the face, shearing a shower of black rock from the seam and sending flecks of it through the air. The noise thunders through the small chamber and it takes effort to speak over the grinding and hydraulic squeaking. When the longwall miner reaches the end of its run and

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Wyoming's coal mining industry is dominated by surface mining operations — complex enterprises that, nevertheless, resemble little more than giant pits. But here inside the state's only underground coal mine, the engineering ingenuity and risk required to extricate energy is unmistakable, like a headlamp in pitch dark.

Underground coal mining is a vanishing art in Wyoming, however. Each chop of the longwall miner's spinning metallic teeth brings this facility closer to the end of its life. Mining down here is expected to come to a halt in December 2021. Mine engineers have it calculated nearly to the day — the mine's last day will be Dec. 9 or maybe Dec. 13, Fox said.

For the roughly 130 underground mine employees, the future is less clear than the closure date. That makes them nervous, Fox said.

"They don't know what the future holds, if it's with this company or trona or what," he said. Coal leaves the mine on a conveyor belt, joining a two-mile system that hauls it from both underground and from the adjacent surface mine to the Jim Bridger Plant, the mines' sole customer. The plant, which burns a blend of the two coals, faces an uncertain future in an era marked by concurrent trends: coal's decline and natural gas and renewables' rise.

Trona mining, which is also done underground, offers hope for the underground coal miners as a next stop for their skills. That industry employed 2,225 employees statewide in 2018, according to the Wyoming Mining Association. The underground miners here are on the younger side, Fox said, many in their 30s. The profession is a lucrative one. Few mining jobs here pay less than $75,000 a year, even entry-level ones, said Scott Palmer, the Bridger Coal Company's Manager of Technical Services.

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After the long wall miner has mined out a chunk of the coal seam, it has to advance. Behind the working miners, a hydraulic-powered roofing system props up the earth above them. When the miners advance that roof, the mine caves in behind them. The process produces a rumble down in the tunnels, an audible reminder of what's on the other side of the machines.

"These are holding up the world," Palmer said. "Behind us the world is collapsing."

Moving the long wall miner requires a carefully calibrated process stressful enough to take years off Fox's life, joked the 62-year-old, a lifelong veteran of underground coal mines who has worked here since the mine's beginning. Miners share the camaraderie of those who work a hazardous job and look out for each other, Fox said.

There are other, more continual hazards to working underground. Miners pump 3,500 gallons of water a minute out of the mine and spray some of it across the coal face and floor in an effort to keep the coal dust down — black lung, an underground miner's affliction, remains a concern though miners here say newer technologies are effective protections.

They travel to their shifts in a personnel carrier. They work 12-hour shifts and eat their meals underground at a mobile "kitchen" equipped with a microwave Work comes in four day blocks, Fox said Working the day shift means four days lived in the dark.

They followed the coal seam

Bridger Coal Company, the mining subsidiary of PacifiCorp, did not originally plan to dig underground. The company started mining on the surface in the 1970s when the power plant was built. By the 2000s, surface mining was becoming more costly — the 30-foot coal seam they'd been mining split, Palmer said. One seam headed downward, and the amount of earth that had to be removed to get to the coal continued to increase.

In 2003, the miners began highwall mining. Highwall mining utilizes an automated miner to drive into the earth along the coal seam at the bottom of a surface mining pit. The miner brings out coal but is limited in how far it can dig. By 2004, the company had opened the underground mine to follow the seam under the earth.

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Since then, the miners have been harvesting the coal in 600-foot-wide panels. They have mined out 20 panels. There are two remaining in their leased area. They are scheduled to reach the end of the final panel at the mine's end date in December 2021.

To mine more coal underground would require a new federal lease, and a spokesperson for mine owner Pacificorp, says they won't go through that onerous process. The underground miners' work will be done.

Once the mine is closed, the ramp plunging into the tunnel in the bottom of the former pit will be filled — a process similar to the reclamation that happens to surface pit mines. The direction of the ramp will be reversed, Palmer said, and it will become shaped as a drainage to match the landscape.

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The reclamation process restores the land to the appearance it held before coal mining, Palmer said. It takes a trained eye to detect the major difference — the disappearance of the bedrock coal. Reclaimed mine land is replanted with native grasses, and is attractive to wildlife, Palmer said, an assertion supported by the number of elk and wild horses roaming the mine property during WyoFile's visit.

Reclamation takes 10 years, Palmer said. The underground mine will be reclaimed by 2031.

"There will be elk walking on it," Palmer said. By then, uninformed visitors likely won't know that once men and women labored in dangerous conditions deep in the darkness to light America's homes and businesses.

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CORRECTION: This story has been updated to note that Bob Fox is 62 years old, not 66 as originally reported. It has also been updated to note that the mine pumps out 3,500 gallons of water per minute, not 35,000, and to more accurately characterize how that water is used. It has also been updated to note that a personnel carrier that brings miners to work is not towed by pick-up truck. — Ed.

This is one of seven stories in WyoFile's "Powering Down" special edition. Click the links below to read more:

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Docket No. UE 374
Exhibit Sierra Club/114
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 114

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Supplemental Testimony of Jeremy Twitchell

Exhibit No. JBT-19HCT
Docket UE-152253
Witness: Jeremy B. Twitchell
REDACTED VERSION

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKET UE-152253**

SUPPLEMENTAL TESTIMONY OF

Jeremy B. Twitchell

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Selective Catalytic Reduction at Jim Bridger

May 6, 2016

CONFIDENTIAL PER PROTECTIVE ORDER

TABLE OF CONTENTS

I. INTRODUCTION 1

II. SCOPE AND SUMMARY OF TESTIMONY 1

III. BACKGROUND 5

IV. THE OCTOBER 2013 MINE PLAN 9

V. THE DECEMBER 2013 OFFICIAL FORWARD PRICE CURVE 24

VI. SUMMARY 30

LIST OF EXHIBITS

Exhibit No. JBT-20C	Confidential Attachment No. 2 to Pacific Power Response to Sierra Club Data Request No. 11
Exhibit No. JBT-21C	Break-Even Analysis (Updated coal price only)
Exhibit No. JBT-22C	October 2013 Mine Plan Increase Calculation
Exhibit No. JBT-23C	Revised Coal Cost Adjustment
Exhibit No. JBT-24C	January 2013 and October 2013 Mine Plan Comparison
Exhibit No. JBT-25C	December 2013 Official Forward Price Curve
Exhibit No. JBT-26HC	EPC Contract Information
Exhibit No. JBT-27HC	Break-Even Analysis (Updated coal and gas prices)
Exhibit No. JBT-28C	Confidential Direct Testimony of Gregory N. Duvall from UE-140762

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeremy Twitchell and my business address is the Richard Hemstad Building, 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington, 98504. My email address is jtwitche@utc.wa.gov.

Q. Are you the same Jeremy Twitchell who previously filed testimony in this case on behalf of Washington Utilities and Transportation Commission Staff?

A. Yes.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. Please summarize your supplemental testimony.

A. My supplemental testimony provides additional analysis of increased coal costs and decreased natural gas costs affecting the decision by Pacific Power & Light Company (Pacific Power or Company) to install selective catalytic reduction (SCR) systems at the Jim Bridger plant (Bridger). Pacific Power identified the changes to Bridger's coal costs in October 2013, one month after it revised its natural gas cost forecasts downward. Both the increased coal costs and the decreased natural gas cost forecast served to erode the cost-effectiveness of installing SCR at Bridger. Pacific Power, however, never analyzed the effect of these two significant cost changes in its System Optimizer Model. Instead, the Company issued the full notice to proceed

with the installation of SCR systems at Bridger on December 1, 2013, based on an outdated analysis that was no longer accurate or valid.

Furthermore, on December 11, 2013, just 10 days after issuing the full notice to proceed, the Company again identified an even sharper decline in its natural gas cost forecasts. Had the Company accounted for these changing circumstances, its analysis of compliance options at Bridger would have identified about $[redacted] million in net benefits associated with natural gas conversion, even when the higher costs associated with cancelling its contract for SCR installation after one month are taken into account.

Pacific Power's refusal to re-evaluate its SCR decision in light of this new information, which on its face called that decision into question, prevented the Company from recognizing that natural gas conversion had become the lower-cost option. On at least two occasions, the Company had new information that justified cancelling its contract for SCR installation at a time when the Company could have done so while saving customers money. Not only did Pacific Power fail to act on these opportunities; there is no evidence that it even evaluated them. Accordingly, the Company's decision to proceed with SCR installation was imprudent.

Q. Please summarize your analysis relating to increased coal costs.

A. My analysis of the Bridger Coal Company (BCC) October 2013 Mine Plan and a third-party coal arrangement in place at that time shows that the cost increases for Bridger's fuel supply that the Company identified in October 2013 likely offset the benefits of SCR installation that the Company identified in its modeling. This

reinforces Staff's argument that installing SCR was an imprudent decision at the time the Company issued the full notice to proceed on December 1, 2013, and that converting Bridger units 3 and 4 to run on natural gas would have been the more cost-effective solution.

Importantly, my supplemental testimony shows that the October 2013 coal price increases *alone* likely rendered the SCR uneconomic.

My testimony reiterates why it is necessary that the prudence of the SCR investment be evaluated in light of the October 2013 Mine Plan, rather than the January 2013 long-term fuel plan that the Company used in its analysis. I then explain how the October 2013 Mine Plan increased both the cost and risk of Bridger's long-term fuel supply, and quantify the impact of the cost increases on the Company's analysis to the extent possible. To conform to the Company's methodology and facilitate the Commission's review, I incorporate the new information that the Company provided on rebuttal regarding how it analyzes the costs identified in a mine plan.[1]

Q. Please summarize your analysis relating to decreasing natural gas price forecasts.

A. Leading up to Pacific Power's decision to issue the full notice to proceed with SCR installation, natural gas price forecasts were dramatically declining. The Company's official natural gas price forecast in September 2013 revealed that the benefits of

[1] Ralston, Exh. No. DR-1CT 5:1-13.

SCR installation had decreased by approximately 30 percent over the previous year.[2] Between that time and when the Company issued the full notice to proceed with SCR installation, the Company received two more forecasts from consultants that identified natural gas price forecasts were continuing to decline. Importantly, 10 days after issuing the full notice to proceed, Pacific Power received new information regarding future natural gas prices from a third consultant that had a major impact on the Company's official natural gas price projection.

My testimony demonstrates that based on the three consultant projections, Pacific Power reduced its official natural gas price forecast so significantly that SCR installation was clearly no longer economic. In fact, that reduction was so significant that had it been used within the context of the decision to proceed with SCR installation, it would have increased the benefits of gas conversion by $[redacted] million.

While I recognize that this information came into the Company's possession after it issued the full notice to proceed, my testimony demonstrates that the Company could have acted on this information, terminated the SCR contract, and still captured most of those $[redacted] million in net benefits by changing course and pursuing gas conversion. My testimony further shows that despite the fact that this information came after issuance of the full notice to proceed, the structure of the Company's contract for SCR installation and the magnitude of the information's impact on the Company's analysis justify the Commission's inclusion of this information in its prudence determination.

[2] The Company's SCR analysis, based on a September 2012 natural gas price projection, identified $[redacted] million in net benefits for SCR. Inputting the September 2013 natural gas price projection indicates that the benefits would fall to about $[redacted] million.

Q. Your response testimony identified an issue related to how Pacific Power's model treated replacement power costs. Does Staff remain concerned with that issue?

A. Yes. My supplemental testimony is limited to the new information related to coal costs and updated natural gas prices that the Company presented on rebuttal. The issue of replacement power costs can be addressed with reference to my response testimony; the fact that I do not discuss it in this testimony should not be interpreted as Staff's acceptance of the Company's rebuttal testimony on that issue. If I were to incorporate this issue into my analysis, it would only further increase the $[redacted] million net benefit associated with natural gas conversion.

III. BACKGROUND

Q. Please explain how mine plans are used in the Company's planning.

A. In his rebuttal testimony, Mr. Ralston explains that a mine plan is a forward-looking budget for BCC that is used in the preparation of the Company's 10-year business plan, which is updated each year.[3] Mine plans are also used in rate cases to support fuel costs.[4] Additionally, mine plans, along with third-party coal contracts, are used as inputs when the Company updates its long-term fuel plans every two years as part of the integrated resource plan (IRP) process.[5]

[3] *Id.* at 3:8-11.
[4] *Id.* at 3:11-15.
[5] *Id.* at 2:18 – 3:1.

Q. Why does Staff consider the October 2013 Mine Plan to be important to the Commission's prudence review of the SCR installation at Bridger units 3 and 4?

A. The Commission has stated that a Company asking for a prudence determination must not only show that it analyzed different options, but that its analysis was based on the *most recent information*.[6] In his rebuttal testimony, Mr. Ralston explains that the Company's SCR analysis is based on a long-term fuel forecast from January 2013, which combined costs from the then-current mine plan and third-party agreements to "provide a comprehensive life-of-plant fueling forecast."[7] Mr. Ralston later explains that long-term fuel plans are prepared on two-year cycles as part of the IRP process,[8] and that the 2013 long-term fuel forecast was based on the January 2013 Mine Plan.[9]

The October 2013 Mine Plan rendered the January 2013 long-term fuel forecast obsolete. In the October 2013 Mine Plan, BCC's share of Bridger's coal supply increased from 68 percent to 85 percent,[10] and as I demonstrate, the costs of BCC coal significantly increased in the October 2013 Mine Plan. If a fuel plan is a combination of the current BCC mine plan and current third-party supply contracts, then in disregarding the October 2013 Mine Plan and sticking to the January 2013 fuel plan, Pacific Power chose to rely on an outdated and inaccurate price forecast for the source of 85 percent of its fuel needs at Bridger.

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[6] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Docket UE-921262, Nineteenth Supplemental Order, 2 (Sept. 27, 1994).
[7] Ralston, Exh. No. DR-1CT 2:19-21.
[8] *See id. at* 2:22 – 3:1.
[9] *Id.* at 4:11-13.
[10] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.,* Docket UE-140762, Exh. No. GND-1CT 19:5-7.

Q. Does Pacific Power consider the October 2013 Mine Plan to be important to the Commission's prudence review of the SCR installation at Bridger units 3 and 4?

A. No. The Company asserts that the October 2013 Mine Plan should not be viewed as a long-term forecast of fuel costs for Bridger.[11] This however, is essentially an argument for a new prudence standard – one that would allow the Company to rely on outdated information when critical new information becomes available outside of its normal planning routine.

As I explained in my response testimony, the Company used the October 2013 Mine Plan to support a rate increase in its 2014 general rate case.[12] If that mine plan created cost increases that were sufficiently known and measurable to support a rate increase, then those cost increases were sufficiently known and measurable to be included in the Company's planning.

Staff cannot determine whether the Company met the Commission's prudence standard, which requires the use of the most current information available, without evaluating the impact of the October 2013 Mine Plan – the most current information regarding future coal costs that was available when the Company committed itself to the SCR installation on December 1, 2013.

[11] Ralston, Exh. No. DR-1CT 3:16-19.
[12] Twitchell, Exh. No. JBT-1CT at 35:14-16.

Q. You mentioned that the Company used the October 2013 Mine Plan in the 2014 general rate case to increase the cost of Bridger fuel in Washington rates. What was the size of that increase?

A. In response to a data request in the instant proceeding, Pacific Power indicated that the fuel costs for Bridger were set at $[redacted] per million British thermal units (mmBtu) in the 2013 general rate case. This response is provided as Exhibit No. JBT-20C. In the 2014 rate case, the Company presented the October 2013 Mine Plan in its initial filing to support a fuel cost of $[redacted] per mmBtu,[13] an increase of 6 percent.

Q. Did the Company support any other increases in rates associated with Bridger's fuel supply in the 2014 rate case?

A. Yes. On rebuttal in that case, the Company presented a July 2014 Mine Plan that it used to support an additional increase to $[redacted] per mmBtu – making for a total increase in Bridger's fuel costs of 18 percent in the 2014 rate case.

Q. Have you reviewed the July 2014 Mine Plan?

A. No. As it was prepared several months after Pacific Power issued the full notice to proceed with SCR installation at Bridger, it is not relevant in evaluating the prudence of the Company's decision. I note that in response to the Sierra Club, the Company conducts extensive analysis based on the July 2014 Mine Plan and January 2015 long-term fuel plan, which was based on the July 2014 Mine Plan, to assert that SCR remained cost effective. I do not understand why the Company chose to conduct

[13] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.,* Docket UE-140762, Exh. No. CAC-1CT at 3, Table 1 and 7:5-7.

these analyses based on the July 2014 Mine Plan, which was not available when it issued the full notice to proceed, rather than the October 2013 Mine Plan, which was available at the time. The Commission should not grant any weight to Company analyses based on the July 2014 Mine Plan and January 2015 fuel plan.

IV. THE OCTOBER 2013 MINE PLAN

Q. Please summarize your conclusions regarding the October 2013 Mine Plan.

A. As I explained in my response testimony, Pacific Power's SCR analysis had three sensitivity analyses related to future natural gas prices: low, base, and high.[14] The costs of Bridger's coal supply were fixed across all three scenarios according to the January 2013 fuel plan, which relied on the January 2013 Mine Plan for BCC costs and third-party supply contracts.

When the October 2013 Mine Plan increases are applied to the Bridger fuel costs that the Company modeled in the base case, the net present value of Bridger's fuel costs from 2016–2030 increases by $[redacted] million. Costs increase by $[redacted] million and $[redacted] million in the high and low gas cases, respectively.

Using the same regression analysis presented by the Company in Exhibit No. RTL-9C and explained in my response testimony,[15] my analysis estimates that had the October 2013 Mine Plan prices been included in the Company's SCR modeling, with no further changes to the Company's inputs, the model would have identified approximately $[redacted] million in net benefits associated with gas conversion. I present

[14] Twitchell, Exh. No. JBT-1CT at 18:21-19:1.
[15] *Id.* at 23:9 – 24:8.

this information in Exhibit No. JBT-21C, which is an updated version of Exhibit No. JBT-4C.

Q. How did you calculate the coal cost increase for each scenario?

A. First, I compared the January 2013 and October 2013 mine plans to determine, on a percentage basis, the degree to which costs increased in the October 2013 plan. Next, I took that increase and the increase associated with the Company's third-party coal supplier, as identified by Mr. Duvall in the 2014 rate case, and weighted each based on its share of Bridger's fuel consumption. Exhibit No. JBT-22C shows this process.

I then used the Company's model data, provided in Mr. Link's initial workpapers in this proceeding, to identify the total fuel expenditures for Bridger that the Company modeled in the low, base and high gas cases. I then calculated a net present value for the modeled fuel costs in each case, and multiplied each figure by the overall weighted increase described above. Exhibit No. JBT-23C shows this process.

Q. What were the drivers of the increased costs in the October 2013 Mine Plan relative to the January 2013 Mine Plan?

A. In the Company's initial filing in the 2014 rate case, Mr. Duvall testified that the Company was rapidly accelerating surface mine production in the October 2013 Mine Plan, but that the cost increases were mostly driven by changes in the underground mine plan resulting from unfavorable conditions for machine-based

longwall mining, which forced the Company to increase its reliance on more expensive miner-based production. Duvall stated:

> The amount of coal produced by the continuous miners has increased from 17.6 percent of the underground mine production in the 2013 Rate Case to 23.7 percent in this filing. This increase reflects the impact of bypassing the 12th right longwall panel due to high ash content, the shortening of the longwall panels, and three longwall moves instead of two in the pro forma period. Bypassing and shortening longwall panels require additional continuous miner production, *which increases production costs*. The variable cost of production for a longwall ton is within a range of $[redacted] per ton to $[redacted] per ton, compared to $[redacted] per ton to $[redacted] per ton for continuous miner production.[16]

Q. Have you conducted any additional analysis of the October 2013 Mine Plan?

A. Yes. Mr. Duvall's testimony focused on the rate year changes identified in the plan to support the Company's proposed pro-forma adjustment in the 2014 rate case, but there were other significant changes in the plan in later years. Exhibit No. JBT-24C provides a side-by-side comparison of the summary tabs from the January and October mine plans for the 2016–2030 period, which provides additional insights.

Q. Are any of those other changes relevant to this discussion?

A. Yes, a key change is that the October 2013 Mine Plan projected that the [redacted]

[redacted]

[16] Docket UE-140762, Exh. No. GND-1CT 21:5-13 (emphasis added).

[redacted]. As I show, this change in strategy has significant impacts on the long-term overall cost of BCC coal.

Q. What conclusions do you draw from the October 2013 Mine Plan?

A. As Mr. Duvall explained, the cost increases in the October 2013 Mine Plan were largely driven by increased variable production costs associated with substituting miner-based production for machine-based production. These variable cost increases represent costs that could have been avoided to some degree by converting Bridger units 3 and 4 to run on natural gas, thereby reducing the plant's coal consumption.

Additionally, the decision [redacted][17] [redacted]. Staff has not quantified this increased risk, but it should be considered when determining whether the Company acted prudently when it committed to the long-term operation of Bridger as a coal-fired resource after this increased risk had been identified.

[17] [redacted]

Q. Have you quantified the increased costs associated with the October 2013 Mine Plan?

A. Yes. I present this analysis in Exhibit No. JBT-22C, which finds that for the period of 2016–2030, coal costs identified by the October 2013 Mine Plan are [redacted] percent higher than in the January 2013 Mine Plan.

Q. Please describe your analysis of the coal cost increase contained in Exhibit No. JBT-22C.

A. The purpose of this exhibit is to provide a comparison between the January and October mine plans in common terms. The mine plans express coal costs in terms of dollars per tons, but the Company's SCR model used coal costs in terms of dollars per mmBtu. Exhibit No. JBT-22C makes this conversion while accounting for the differences in both the amount and distribution of production between the surface and underground mines in the two plans and also accounting for differences in assumed heat content of BCC coal between the two plans.

The exhibit has two tabs – one for January 2013, and one for October 2013. The first section on each tab is Production, which identifies total projected production amounts and how that production breaks down between the surface and underground sections of the mine. Beneath each of those totals is a row labeled "PAC Share," which multiples production amounts by two-thirds to represent the share of output for which Pacific Power, as a two-thirds owner of both Bridger and BCC, would be responsible. The remaining rows of this section identify the variable

production (cash) costs for each year's production forecast and the projected mine capital expenditures for each year.[18]

The next section on each tab is the Heat Content section, which identifies the different assumed heat content of coal from each section of the mine, in Btu per pound. Using the breakdown of production between the surface mine (which generally produces coal with a lower heat content) and the underground mine (which generally produces coal with a higher heat content), this section concludes by calculating the total heat content of the coal delivered from BCC to the Bridger plant, in mmBtu.

The next two sections of each tab express the total costs on a dollars per mmBtu basis, then levelize those costs for the purposes of comparing the costs of the two plans. One section does this for cash costs; the other section does this for cash plus capital costs. The "October 2013 Mine Plan" tab also has a final section that calculates the increases relative to the January 2013 Mine Plan in various terms.

Q. Does Staff's revised analysis, based on the actual October 2013 mine plan, take into account any of the issues with Staff's treatment of mine plan costs that Pacific Power identified in its rebuttal filing?

A. Yes, it does. In order to be as accurate as possible, my analysis and calculations reflect the clarifications that the Company provided on rebuttal regarding how it models coal costs.

[18] Mine capital expenditures have been multiplied by two-thirds so that they are expressed on a Pacific Power share basis.

Q. What are the issues that Pacific Power raised and that you have resolved in your analysis and calculations associated with the October 2013 mine plan?

A. Aside from pointing out that Staff's initial analysis relied on the same January 2013 Mine Plan used by the Company, Mr. Ralston identified three issues:

- Staff did not account for capital cost differences;
- Staff did not account for the cost of coal provided by third parties; and
- Staff used operating costs in its analysis, rather than the cash costs used by the Company in its SCR analysis.[19]

Q. Were you aware of these issues when you filed your testimony?

A. I was only aware of the third-party coal issue, and explained in my testimony why I chose to omit third-party coal costs.[20] The cost differential for Black Butte coal – the Company's third-party supplier – is more impactful when compared to BCC's cash costs, so I have included the cost of Black Butte coal in this analysis, though its impact is minimal.

I was not aware of the difference between mine plan operating costs and cash costs until the Company filed its rebuttal testimony. Although Mr. Link references cash costs in Exhibit No. RTL-3C, there was no explanation of how these were determined in his testimony, and the Company did not explain the matter when it directed Staff to the January 2013 Mine Plan in its initial response to Staff Data Request No. 99. It did not become clear to me how cash costs are extracted from the

[19] Ralston, Exh. No. DR-1CT at 5:1-13.
[20] Twitchell, Exh. No. JBT-1CT at 35:11 – 36:2.

mine plan's operating costs until after I received the Company's supplemental response to Staff Data Request No. 99 on April 18, 2016, and had a subsequent discussion with the Company.

Similarly, I was not aware that the mine plan to which the Company referred me in its initial response to Staff Data Request No. 99 did not include capital costs in its summary costs until the Company filed its rebuttal testimony.

Q. How does the Company calculate cash costs?

A. In its supplemental response to Staff Data Request No. 99 provided via email on April 16, 2016, the Company indicated that it had provided the October 2013 Mine Plan in response to Sierra Club Data Request No. 1.6(a). The Company also indicated that the October 2013 Mine Plan was filed in the workpapers of Sierra Club witness Dr. Jeremy Fisher, and provided the relevant workpaper as an attachment to the email.

In the referenced attachment, Dr. Fisher's workpaper identified four line items that are removed when the Company calculates cash costs: depreciation and amortization, depletion, coal inventory adjustment, and deferred longwall amortization. In a subsequent discussion, the Company informed me that the deferred longwall amortization expense is, in fact, included in the Company's cash cost calculation. The Company did not identify this issue when it directed me to the workpapers of Dr. Fisher, which clearly identified the deferred longwall amortization expense as being excluded from cash costs, and did not clarify the matter until more than two weeks after it had provided the supplemental response.

Q. How does your analysis account for cash costs?

A. Based on the information provided by the Company in its supplemental response to Staff Data Request No. 99 and in further conversation, my calculation of cash costs removes three line items from BCC's cost summary: depreciation and amortization, depletion, and coal inventory adjustments. My calculation of BCC cash costs can be seen in Exhibit No. JBT-24C, on row 61 of each tab. The three costs that are removed in the cash cost calculation are in the highlighted rows on each tab. These cash cost calculations are used as inputs in my analysis of increased coal costs contained in Exhibit No. JBT-22C.

Q. What are your findings relating to cash costs?

A. As seen in cell B31 on the "October 2013 Mine Plan" tab of Exhibit No. JBT-22C, the October 2013 Mine Plan increased the cost of BCC coal by [redacted] percent on a cash cost basis.

Q. How does your analysis account for capital expenditures?

A. Each mine plan had an accompanying capital expenditure forecast.[21] I took the forecast from each plan and multiplied each year's forecasted expenditure by two-

[21] The forecasts are in different places in each plan. In the January 2013 Mine Plan, which I have provided as a workpaper under that title, the capital expenditure forecast was provided on the "OPEX" summary tab on row 222. In the October 2013 Mine Plan, capital expenditures for the first 10 years were identified in a separate document, which the Company provided in response to Sierra Club Data Request 1.6 and which I have provided as a workpaper under the title "October 2013 Mine CAPEX Plan." Capital expenditures are identified in that document on the "SUM" tab in column S; the adjustment to express those costs on a Pacific Power basis can be seen in column U, rows 63-70. The remaining October 2013 Mine Plan capital expenditures (2024-2030) can be found in the "October 2013 Mine Plan" workpaper, on the "OPEX" summary tab, row 222.

thirds to reflect Pacific Power's ownership share of BCC. The resulting figures are in Exhibit No. JBT-22C, on row 9 of each tab.

Q. How do capital expenditure forecasts vary between the two plans?

A. As I explained above, October 2013 Mine Plan reflected the Company's decision to [redacted], which results in a major reduction in long-term capital expenditures. On a net present value basis, Pacific Power's share of capital expenditures from 2016–2030 decreases by about 44 percent in the October 2013 Mine Plan.

Q. What is the impact of including capital costs in your analysis?

A. The decrease in capital costs significantly offsets the cash cost increase between the two plans. As shown in cell B32 of the "October 2013 Mine Plan" tab of Exhibit No. JBT-22C, when the analysis accounts for capital costs, the increase falls from [redacted] percent to [redacted] percent.

Q. How does the analysis account for third-party coal costs?

A. In the 2014 rate case, Mr. Duvall testified in his direct testimony that in the 2013 Mine Plan, BCC accounted for 85 percent of Bridger's fuel and the Black Butte Mine provided the remaining 15 percent.[22] Mr. Duvall further testified that the cost of Black Butte coal rose in that case from $[redacted] per ton to $[redacted] per ton, an increase of [redacted] percent.[23]

[22] Docket UE-140762, Exh. No. GND-1CT at 19:3-7.
[23] *Id.* at 20:7-10.

I relied on these figures to determine the impact of the Black Butte coal agreement on the overall cost of Bridger's fuel. Once I determined the overall increase for BCC coal identified in the October 2013 Mine Plan, including capital costs, I weighted that increase by 85 percent and the [redacted] percent increase for Black Butte by 15 percent. This calculation yielded an overall increase of [redacted] percent in the cost of Bridger fuel resulting from the October 2013 Mine Plan, the calculation of which can be seen in cell B33 of the "October 2013 Mine Plan" tab of Exhibit No. JBT-22C.

Q. How did you apply this increase to the Company's analysis?

A. Please refer to Exhibit No. JBT-23C. Since the Company represents that the January 2013 fuel plan used in its analysis combined a BCC mine plan and a third-party coal supply agreement, and my analysis used the most recent versions of those same two components based on their shares of Bridger fuel supply as of October 2013, I applied the increase that I calculated to the fuel costs that the Company modeled using the January 2013 fuel plan.

I obtained the modeled fuel costs for the Bridger plant in each of the three natural gas price scenarios that the Company modeled, determined the net present value of fuel costs in each scenario, and multiplied that figure by [redacted] percent. This results in an adjustment of $[redacted] million in the low gas case, $[redacted] million in the base gas case, and $[redacted] million in the high gas case.

Q. What is the overall impact of these coal cost adjustments?

A. Please refer to exhibit No. JBT-21C. Page 1 of the exhibit shows the impact of the adjustment on the Company's regression analysis, including the new break-even price point for natural gas conversion to become cost effective. Page 2 shows the coal cost adjustments being applied to the model, and page 3 shows that using the Company's September 2013 OFPC, the model would have identified about $[redacted] million in net benefits for gas conversion.

Q. Did you analyze the impact of the October 2013 Mine Plan on the gas conversion case, in which Bridger units 1 and 2 would have continued to operate as coal-fired units?

A. No. There was not enough information in this case for Staff to determine how the coal cost increases identified in the October 2013 Mine Plan would affect the gas conversion case. Ultimately, only Pacific Power could conduct such an analysis.

The Company's SCR analysis relied on the January 2013 Mine Plan, which was developed to evaluate two different scenarios: one reflecting four units of Bridger operating on coal (the SCR scenario), and one reflecting two units of Bridger operating on coal (the gas conversion scenario). The October 2013 Mine Plan, in contrast, was only prepared based solely on the four-unit SCR scenario – suggesting that the Company had no intention of re-evaluating the relationship between SCR and natural gas conversion based on the October 2013 Mine Plan. Staff could not replicate the January 2013 Mine Plan's two-unit scenario for the October 2013 Mine Plan.

Staff identified no clear relationship between the four-unit and two-unit mine plans used in the Company's SCR analysis, and the conclusions of the two-unit plan appear counterintuitive. For example, overall production by BCC from 2016–2030 decreases by [redacted] percent in the two-unit plan relative to the four-unit plan, but Exhibit No. RTL-3C shows that on a levelized basis, cash costs only decrease by about [redacted] percent in the two-unit plan. By the Company's own implication, cash costs are the costs that vary according to production,[24] so their failure to track with reduced production is puzzling.

Additionally, the differences between the January 2013 Mine Plan and the October 2013 Mine Plan further complicate any attempt at estimating what a two-unit plan would look like relative to the October 2013 Mine Plan. [redacted]

Preparing a two-unit mine plan based on the October 2013 Mine Plan would require not only an understanding of how mine operations would generally change in a two-unit scenario, but also an understanding of how they would change in light of the significant changes presented in the October 2013 Mine Plan. Pacific Power is the only party to this case with sufficient information to prepare such a plan, and there is no evidence that the Company did so.

[24] Link, Exh. No. RTL-11CT 6:5-12.

Q. If the October 2013 Mine Plan increased fuel costs for the four-unit SCR scenario, would it also necessarily increase fuel costs for the two-unit gas conversion scenario?

A. I do not believe that would be the case. The nature of the two-unit mine plan prepared in January 2013 suggests that when it is conformed to the long-term strategy changes adopted in the October 2013 Mine Plan, costs for the two-unit scenario would likely decrease.

As I explained above, Exhibit No. RTL-3C shows that on a levelized basis, coal cash costs between the four-unit and two-unit scenarios used in the Company's SCR analysis are similar. Looking closer at this exhibit, it becomes clear that the reason levelized costs are so similar between the two cases is because the two-unit scenario has three high-cost years at the front end (2016–2018), which inflates the levelized cost of the scenario.

Q. Why does the two-unit scenario have three high-cost years in the early years of the plan?

A. The reason for these early, high-cost years is explained in the January 2013 two-unit mine plan.[25] The higher costs are driven by the surface mine, which in the two-unit plan [redacted]

[25] This document is filed as a workpaper under the title "January 2013 – 2 Unit."
[26] "January 2013 Mine Plan" workpaper, "OPEX" tab, row 115.

[redacted].[27] This decision results in significantly higher cash costs for surface coal, ranging from $[redacted] per mmBtu in 2016 to $[redacted] per mmBtu in 2018. [redacted]

Q. Why would fuel costs for the two-unit gas conversion scenario likely decrease?

A. The reason that costs for a two-unit scenario would likely decrease from January 2013 to October 2013 is because the October 2013 Mine Plan [redacted]

Furthermore, surface production is subject to economies of scale; the more surface coal that BCC produces, the lower its per-unit cash costs get. For example, in the January 2013 Mine Plan, the surface mine averages [redacted] million tons per year from 2016 to 2030, at an average cash cost of $[redacted] per mmBtu. In the October

[27] "January 2013 – 2 Unit" workpaper, "OPEX" tab, row 115.

2013 Mine Plan, average surface mine production increases to [redacted] million tons per year and the average cash cost falls to $[redacted] per mmBtu.

These figures establish a clear, inverse relationship for the surface mine's cash costs: as production goes up, per-unit cash costs go down. The October 2013 Mine Plan's decision to [redacted] strongly suggests that the early years of a two-unit scenario based on the October 2013 Mine Plan would have a lower cash cost than the same years in the two-unit scenario developed from the January 2013 Mine Plan. The availability of [redacted] in the October 2013 Mine Plan would also serve to push cost increases further out. These two factors – lower costs in early years and increase costs shifted out to later years –indicates that on a levelized basis, coal costs for a two-unit scenario in October 2013 would likely have been lower than coal costs for the two-unit January 2013 plan that the Company used in its SCR analysis.

Q. How would the lower cash costs for a two-unit scenario in October 2013 impact Staff's analysis of the net benefit in favor of gas conversion?

A. Adjusting the SCR scenario's costs to reflect the October 2013 Mine Plan identifies $[redacted] million net benefits in favor of gas conversion. As I have explained, costs for the natural gas scenario based on a two-unit mine plan from October 2013 would likely be lower than the costs that the Company modeled based on the two-unit mine plan from January 2013, which would reduce the cost of the gas conversion scenario and thereby increase the net benefits of gas conversion. Staff's estimate of $[redacted]

million in net benefits in favor of gas conversion based on the October 2013 Mine Plan should therefore be taken as a conservative estimate.

V. THE DECEMBER 2013 OFFICIAL FORWARD PRICE CURVE

Q. Please describe the role of natural gas prices in the Company's SCR analysis.

A. When Pacific Power prepared its SCR analysis, it also prepared the regression model presented in RTL-9C that determined that for gas conversion to become cost effective, the levelized forward price of natural gas would have to be $[redacted] per million British thermal units (mmBtu) or lower. Pacific Power monitors natural gas markets through its Official Forward Price Curve (OFPC), which is an internally generated natural gas price forecast that is informed by projections obtained from three consultants and updated on a quarterly basis.

The SCR analysis was based on the September 2012 OFPC, which identified a levelized forward price of $[redacted] per mmBtu. A year later, the September 2013 OFPC identified a forward levelized price of $[redacted] per mmBtu; this is the price that Pacific Power compared to the $[redacted] per mmBtu breakeven price point identified in its regression model when it decided to issue the full notice to proceed with SCR installation in December 2013.

As I explained in my initial testimony, natural gas price assumptions have a major impact on the outcome of the Company's SCR model. Changing the levelized forward price of natural gas by just one penny swings the outcome of the model by $[redacted] million – an increase of a penny increases the benefits of SCR installation by

$[redacted] million, and a decrease of a penny increases the benefits of gas conversion by $[redacted] million.

Q. You previously testified that in evaluating whether Pacific Power acted prudently when it installed SCR, the Company should only be held accountable for "the information that was in its possession" when it issued the full notice to proceed. Is this still Staff's position?

A. No. Based on new information provided by the Company in its rebuttal case and subsequent discovery, it became apparent to Staff that the Company came into new information regarding natural gas price forecasts between October and December 2013 that significantly improved the cost effectiveness of gas conversion. Had Pacific Power considered that information alongside the coal cost increases it identified in the October 2013 Mine Plan, the Company would have identified natural gas conversion as the clearly most cost-effective compliance alternative for Bridger units 3 and 4.

Importantly, the Company could have still availed itself of flexibility built into its engineer, procure and construct (EPC) contract for SCR installation and cancelled the SCR project in January 2014, while still capturing the majority of the increased benefits of gas conversion that were identified in December 2013. Staff therefore concludes that it is reasonable to consider the Company's decision to install SCR based on what it knew as of January 1, 2014.

Q. Please describe the new information regarding natural gas price forecasts that the Company received between October and December 2013.

A. Subsequent to the development of the September 2013 OFPC, Mr. Link testifies on rebuttal that the Company received updated forecasts from its three consultants.[28] Two of these consultants provided updates in October and November, which reflected moderate reductions in their natural gas price projections. On December 11, 2013, ten days after issuing the full notice to proceed with SCR installation, the Company received the last of these updates.[29] This last update was from the consultant that had provided the highest projection of natural gas prices for the September 2013 OFPC, and its update reflected a significant decrease that would, in turn, have a significant impact on the Company's own projections. When the OFPC was updated on December 31, 2013, Pacific Power's official levelized forward price fell from $[redacted] per mmBtu to $[redacted] per mmBtu.[30]

Q. Had the Company applied the December 2013 OFPC to its SCR analysis, what would have been the impact?

A. Setting aside Staff's coal cost adjustment and applying *only* the December 2013 OFPC to the Company's regression model, it predicts that the analysis would have only identified about $[redacted] million in net benefits associated with SCR installation. This figure is almost 90 percent lower than the $[redacted] million in net benefits that the Company identified in its initial analysis, which was based on the December 2011

[28] Link, Exh. No. RTL-11CT 18:5-12.
[29] *Id.*
[30] Twitchell, Exh. No. JBT-25C.

OFPC. Relative to the September 2013 OFPC, the December 2013 OFPC created a $[redacted] million swing in favor of gas conversion, reducing the net benefits of SCR conversion from $[redacted] million to $[redacted] million.

Therefore, in just the two years from December 2011 to December 2013, the Company had seen nearly all of the benefits it identified for SCR installation swallowed up by declining natural gas prices. Not only was this trend sustained; it was accelerating. In the year between the September 2012 and September 2013 OFPCs, the Company's levelized forward price for natural gas fell by 6.5 percent. Then, in just the three months between the September 2013 and December 2013 OFPCs, it fell by another 6.5 percent.

A reasonable board of directors would have recognized this powerful trend and responded by extricating the Company from the SCR project, which was growing riskier by the day.

Q. But the Company issued the full notice to proceed to the EPC contractor on December 1, 2013 – 30 days before generating the December 2013 OFPC. How could it have backed out of the project at that point?

A. The EPC contract was designed with significant flexibility around the full notice to proceed; [redacted][31] This flexibility is central to Staff's argument in this case – that the low exit fees on December 1, 2013, coupled with the new cost information that became available during the limited notice to proceed phase,

[31] Twitchell, Exh. No. JBT-12C.

justified the Company exiting the EPC contract at that time and pursuing gas conversion.

The Company, however, had continued flexibility—albeit at a higher cost—after the issuance of the full notice to proceed, for at least the first month of the EPC contract. Although the cost to exit the contract in January 2014 was higher than it was in December 2013, that cost was only a small fraction of the increased benefits that the December 2013 OFPC identified for gas conversion.

The same logic that Staff used in supporting a December 1, 2013 date for determining prudence also supports a January 1, 2014 date, given the additional information provided in rebuttal and subsequent discovery. That is, if the benefits of natural gas conversion out-weighed the costs of getting out of the EPC contract, then the prudent course of action would be to cancel the SCR project and pursue natural gas conversion.

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Q. [redacted]

A. [redacted]

Q. You have presented how the increased coal costs and decreased gas costs affect the model independently. What happens when they are combined?

A. Please refer to Exhibit No. JBT-27HC. This exhibit is an updated version of Exhibit No. JBT-21C. The first exhibit presented only the impact of coal costs on the analysis; the latter exhibit presents the impact of the coal and natural gas costs together. The first page of Exhibit No. JBT-27HC shows the impact of these adjustments on the regression analysis and the new breakeven price. The second page shows the adjustments that Staff applied to the model; it has been marked

highly confidential because it contains the costs associated with terminating the EPC contract on January 1, 2014. The third page of the exhibit shows that with these adjustments applied, the breakeven price at which natural gas conversion becomes cost effective rises to $[redacted] per mmBtu, and that at the December 2013 OFPC levelized forward price of $[redacted] per mmBtu, the model identifies $[redacted] million in net benefits associated with natural gas conversion.

VI. SUMMARY

Q. Please summarize your testimony.

A. My testimony has demonstrated that, when taken independently, increased coal costs from the October 2013 Mine Plan and decreased natural gas costs from the December 2013 OFPC each demonstrate that the decision to install SCR was uneconomic, or at a minimum, was moving in that direction at an accelerating pace. Accounting for either one of these trends would have led a reasonable board of directors to scuttle the SCR project and pursue natural gas conversion; when both are taken into consideration, there is no question that SCR had become uneconomic.

That Pacific Power recommitted itself to SCR at every opportunity reflects a willingness to ignore not only obvious trends in the industry, but the Company's own data. It should not be forgotten that the October 2013 Mine Plan and the December 2013 OFPC are both products of Pacific Power. While there has been some dispute over how these documents are evaluated, the fundamental point of disagreement between Staff and the Company is whether they are relevant in the context of the

Company's SCR analysis. The Commission has clearly articulated that an analysis presented in support of a resource acquisition must be based on the most up-to-date information.[32] Pacific Power's decision to install SCR, and then recommit itself to that decision at every opportunity for re-evaluation, fails this most basic component of a prudence review.

When Pacific Power issued the full notice to proceed with SCR installation on December 1, 2013, the October 2013 Mine Plan represented the most accurate, up-to-date information regarding the Company's future coal costs for the Bridger plant. Staff's objective analysis of this mine plan, on the terms spelled out by the Company, demonstrates that there were significant increases in Bridger's coal costs between January 2013 and October 2013.

In relying on the January 2013 long-term fuel forecast when it decided to move forward with the SCR installation, the Company disregarded crucial, updated information that would have changed the outcome of its analysis and identified gas conversion as the more cost-effective compliance option. The fact that Pacific Power failed to incorporate these costs and act accordingly locked the Company and its ratepayers into a more costly, more risky compliance path.

When Pacific Power determined on January 1, 2014, that SCR remained the best alternative, it failed to consider the December 2013 OFPC, which had nearly wiped out the benefits associated with SCR and demonstrated that what few benefits remained were being rapidly eroded. The September 2013 OFPC upon which the Company hangs its final decision had been shown to be obsolete and inaccurate at a

[32] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Docket UE-921262, Nineteenth Supplemental Order at 2.

time in which the Company still had enough flexibility to alter course. Pacific Power chose not to.

Taken together, these crucial developments identify about $[redacted] million in net benefits associated with gas conversion. These benefits have only increased as the very trends the Company ignored in its decision – rising coal costs and falling natural gas costs – have both continued to unfold.

Staff therefore stands by the recommendation presented in my response testimony – that the Commission disallow the incremental cost of the SCR installation relative to the gas conversion, as well as all costs associated with the other major maintenance projects that could have been avoided by gas conversion.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE 374
Exhibit Sierra Club/115
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 115

CONFIDENTIAL

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

This exhibit is confidential pursuant to Protective Order 20-040 and is provided in Excel format under separate cover.

Docket No. UE 374
Exhibit Sierra Club/116
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 116

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

2012 Natural Gas Request for Proposals Workshop



2012 Natural Gas Request For Proposals Workshop

October 29, 2013



PACIFICORP | Rocky Mountain Power
Pacific Power
PacifiCorp Energy

Agenda

- Objective of the workshop
- Discussion items
- Current evaluation process
- Credit requirements
- Cost of credit calculation
- Price forecast
- Market drivers

Objective

- Consistent with the 2013 Integrated Resource plan action item 5a and the Utah Stipulation, the Company will conduct the following:

Action Item 5a: Convene a workshop for stakeholders by October 31, 2013 to discuss potential changes to the Company's process in evaluating bids for future natural gas requests for proposals, if any, to secure additional long-term natural gas hedging products

Utah Stipulation: Specific discussion items (next slide)

Discussion Items

- The possibility of establishing a standard approach to bid evaluation based on specific terms or product definition such that the bids within specific product definitions or bids for specific terms can compete against each other

- A review of whether a change in the process related to the evaluation of the cost of credit is required and, if so, the type of changes that should be implemented
  - Changes to the methodology
  - Changes to the timing of the cost imputation

- A discussion seeking and understanding the data that would be used to evaluate a costless collar beyond the 48 month of market data

Review of Current Evaluation Process

- Request for proposal contained eight bid types
  - Fixed-Price Physical
  - Fixed-Price Physical without Quarter Two
  - Financial Swap
  - Physical Call Option
  - Financial Call Option
  - Physical Zero-Premium Collar
  - Financial Zero-Premium Collar
  - Physical Cost-Based
- Bids are grouped by tenor, bid category (cost-based, collar, option and fixed-price), and location
- Only bid categories with at least one favorable bid (less than 100% market ratio) are retained through the initial screening

Current Evaluation Process

- Price score
  - RFP Base Model is used to evaluate bid costs against a comparable market alternative for a given term, supply pattern, and point of delivery
  - The "market ratio" establishes the price score for all bid types. For bid types other than collars, it is calculated as follows:
    - Levelized bid costs on a $/MMBtu basis divided by the levelized market value of the bid
    - Bids are ranked by ascending market score, with lowest scores being the most favorable
  - For collars, the "market ratio" is defined as follows
    - Collars are modeled as the combination of a short put and long call
    - The value of the short put is divided by the value of the long call
    - Bids are ranked by ascending market score, with lowest scores being the most favorable

Credit Requirements

- The final shortlisted bidders were either creditworthy or had provided a parental guaranty from a guarantor that was creditworthy

- Each of the final shortlisted bidders had executed the ISDA Master Agreement with a margining agreement in a form acceptable to the Company
  - The margining agreement contractually requires a bidder to post collateral to the Company when the Company has credit exposure to the bidder that exceeds the bidder's margin threshold, with the converse being true as well
  - Margin thresholds are based on current credit ratings and are negotiated prior to contract execution
  - The margin threshold is the maximum level of unsecured credit exposure a party is willing to assume with the other party
  - Credit exposure that exceeds the margin threshold is collateralized with cash or a letter of credit, per the terms of the underlying margin agreement

Credit Exposure

- The Company determined the peak potential credit exposure for each shortlisted bid, using standard statistical analysis

- For the final shortlisted bids, the actual potential credit exposure of the Company to the bidder was limited to the lesser of the calculated peak potential exposure or the amount of the bidder's margin threshold, since any credit exposure above the threshold is secured, per the terms of the underlying agreement

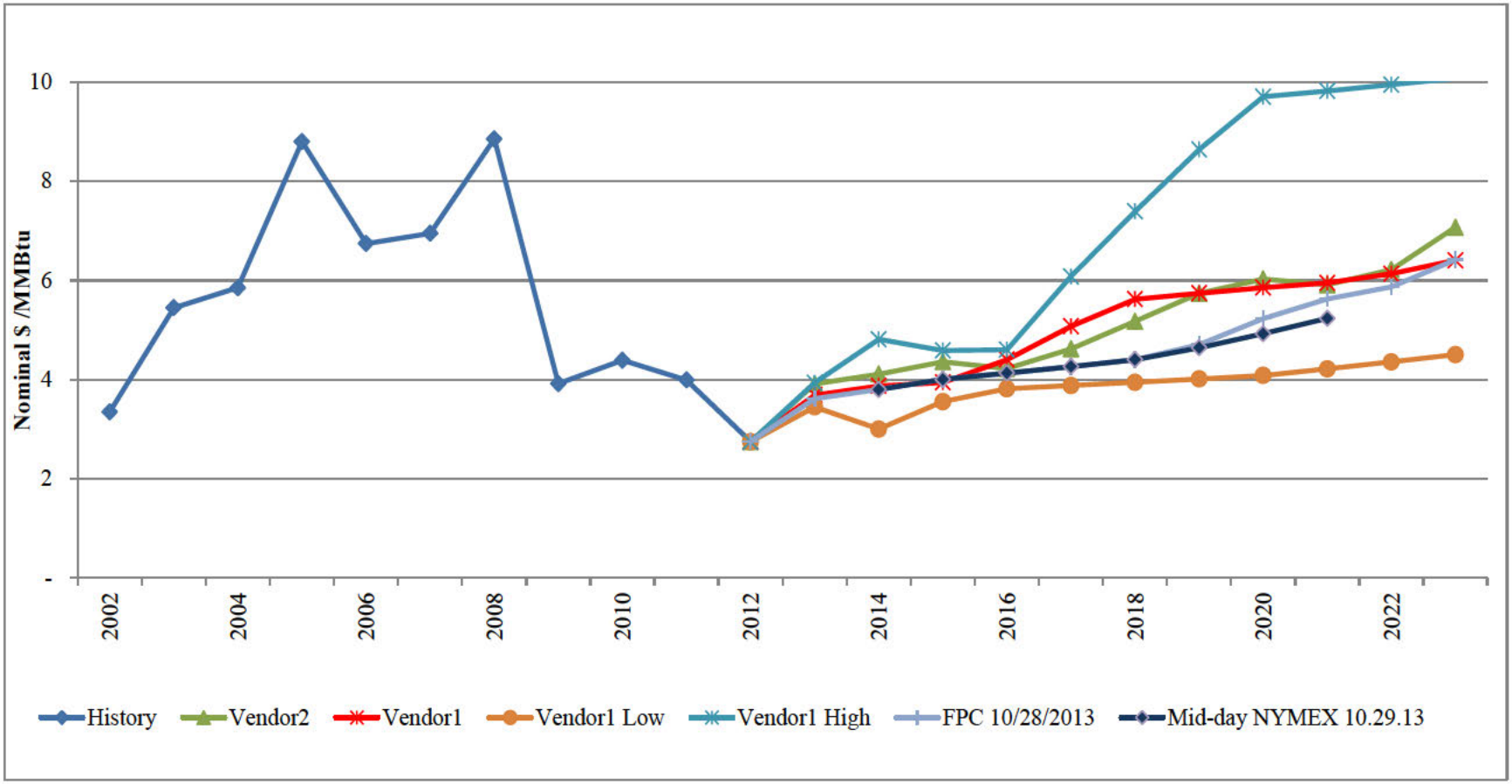
- For each of the final shortlisted bids, the actual potential credit exposure, or lesser value, was limited to the bidder's margin threshold

Cost of Credit Calculation

- A total notional cost of credit was determined for each shortlisted bid using the bidder's credit default swap (CDS) rate, which was multiplied by the bidder's margin threshold and which was in turn multiplied by the term of the transaction

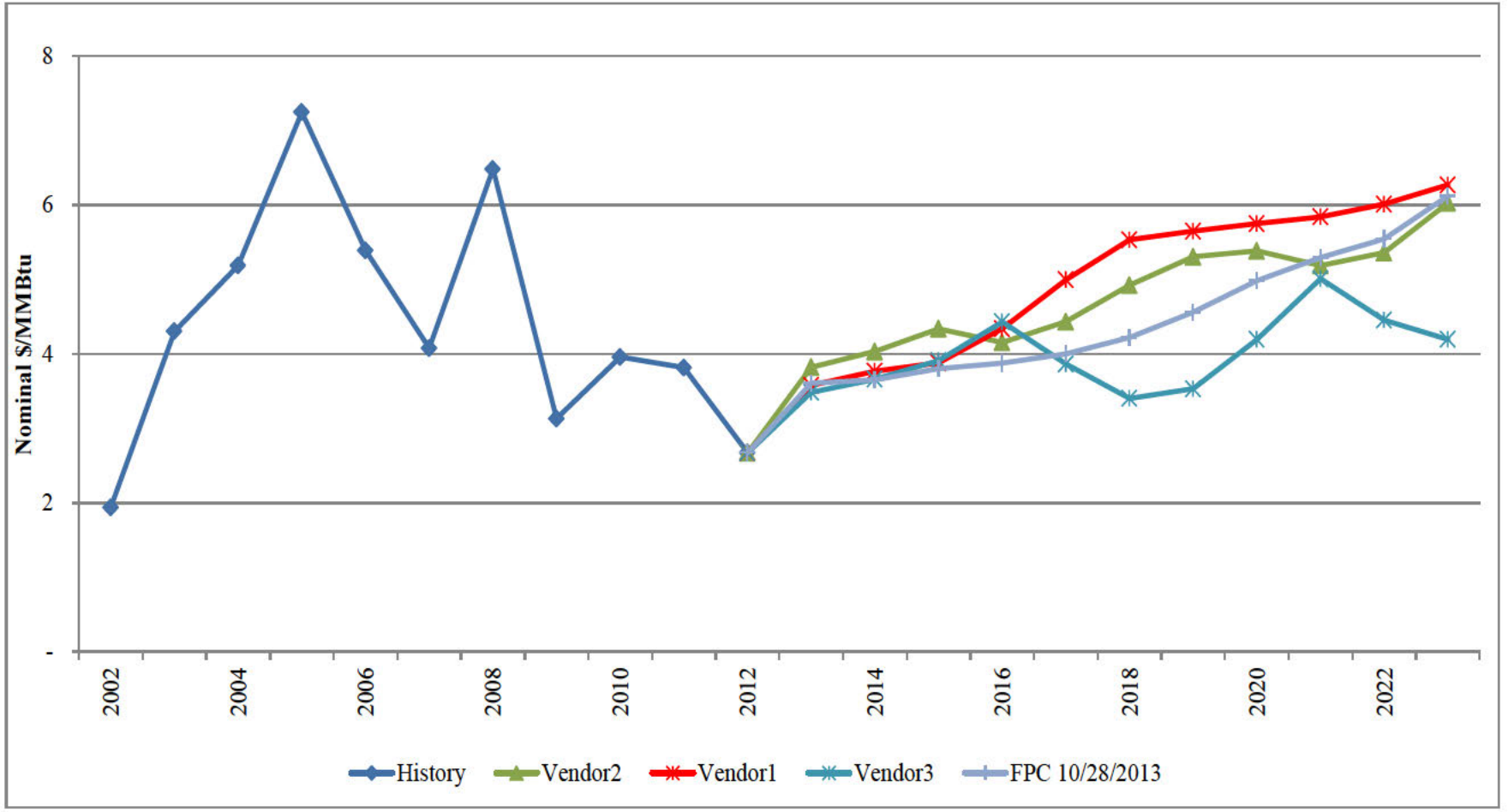
- This total notional cost of credit was then divided by the total volume (in MMBtu) to be delivered over the transaction term in order to determine the notional cost of credit per/MMBtu for each bid
  - The CDS rate represents the cost of credit insurance and was used to estimate the premium charged by the capital markets to insure against credit risk: i.e., the expense to insure against default on a company's debt
  - The CDS rate is based on each bidder's unique risk profile and is independent of any proposed bid
    - The CDS rate was obtained from Bloomberg L.P. and is published in basis points per annum
    - The rate was converted to a monthly rate for the purposes of the cost of credit calculation.

Henry Hub Price Forecasts



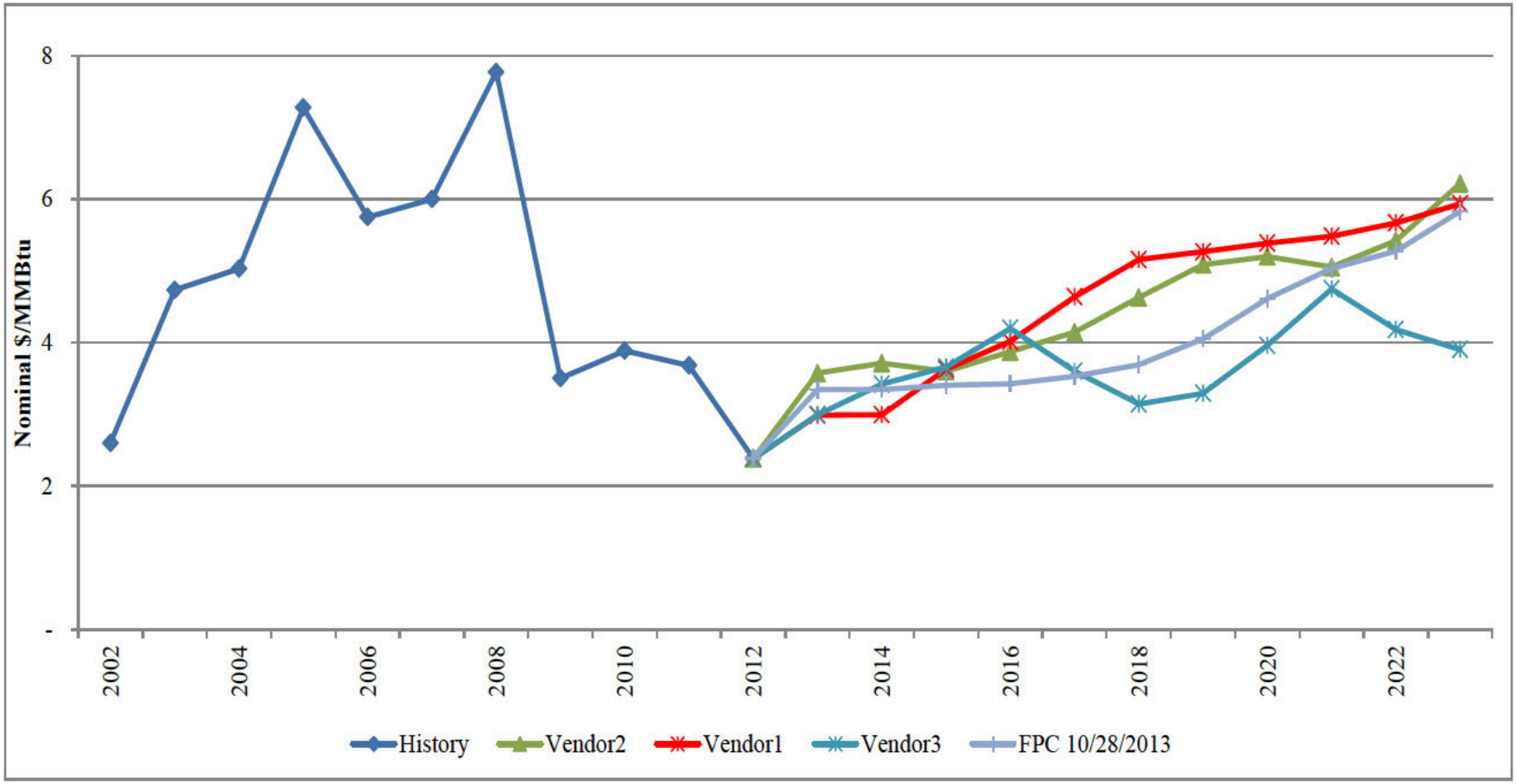
- HH will maintain a widening premium over Opal and AECO through 2024. On the demand side ,this premium is brought on by the increased natural gas demands of LNG exports, industry, exports to Mexico, and power demand in the Gulf Coast.
- An incremental 6 BCF/day of lower 48 LNG exports is expected by 2021 (including the recently approved Freeport facility) .

Opal Price Forecasts



- An upside price risk is the closure of SONGS which is not completely captured in these forecasts; the closure of SONGS may provide price support for Opal in serving the California market. Another upside price risk is when Canadian LNG export facilities come online (2022), Opal will have a competitive advantage, over AECO, in serving the California market.
- A downside price risk is the potential for continued and increased supply from technology improvements and the continued westward push of Marcellus and Utica natural gas.

AECO Price Forecasts



- A downside price risk for AECO would be the delay or cancelation of Canadian LNG export facilities. Another downside price risk is that Marcellus and Utica shale gas continue to push Canadian gas out of the US, thereby stranding AECO supplies.
- A possible upside price risk is increased natural gas use in Alberta for tar sand development coupled with heavy Canadian LNG export development.

Market Fundamental Drivers

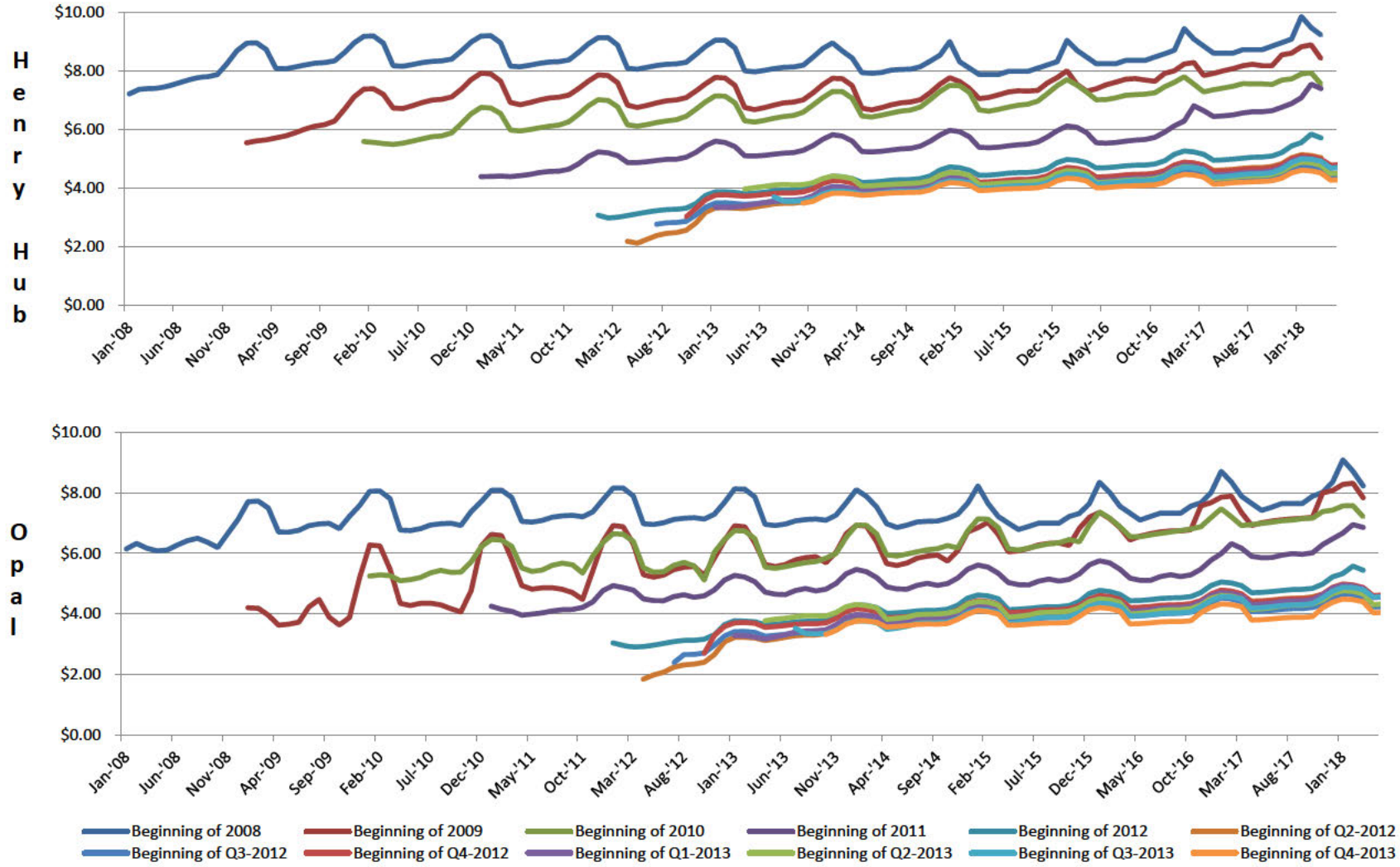
Downside Risks

- Continued westward push of Marcellus and Utica shale gas keeps Canadian gas at AECO.
- Continued rig efficiencies usher in production gains using fewer rigs. Overall, oil and gas production is up 57% in Eagle Ford alone.
- Associated gas in the Bakken and Niobrara coupled with development of the Montney and Duvernay shales support western gas production .
- Downside risks are most pronounced in the short term (2-3 years).

Upside Risks

- Closure of SONGS provides price support for Opal.
- Canadian LNG export opportunities in the early-mid 2020's provide price support for AECO.
- Increased tar sand development in Alberta provides strong price support for AECO.
- Opal receives price support in the mid 2020's with the expansion of Rockies take-away capacity.
- Increased demand from the industrial, power, transportation, and export sectors provides continued price support for Henry Hub especially.

Forward Price Curves



*Forward price curves have decreased almost steadily from 2008 to 2013. However, each curve shows increasing prices.

Source: PacifiCorp Official FPC

Docket No. UE 374
Exhibit Sierra Club/117
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 117

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

PacifiCorp Response to Sierra Club Data Request 4.10

Sierra Club Data Request 4.10

See the Direct Testimony of Cindy Crane 428-439.

(a) To what extent are the current cost increases attributable to reduced coal production at BCC expected to be maintained through future years (i.e. after the 2014 test period), or be relieved once production increases?

(b) At what date will costs attributable to reduced coal production be relieved? Why?

(c) If costs are expected to decrease significantly after the advancement of the 13th longwall panel or other changes at BCC, will PacifiCorp expediently file a new GRC to reflect those reduced costs? If no, why not?

(d) To what extent were the increased costs described in pages 20-24 of Ms. Crane's testimony incorporated into the Wyoming CPCN and Utah voluntary approval docket for the Bridger 3 & 4 SCRs? (Wyoming Docket No. 20000-418-EA-12 and Utah Docket UE 12-035-92) Please explain any discrepancies and their impact on the outcome of the analysis accompanying that proceeding.

Response to Sierra Club Data Request 4.10

(a) Bridger Coal costs trend lower starting in the latter part of 2015.

(b) See response to Sierra Club 4.10a.

(c) If costs decrease significantly after the advancement of the 13th longwall panel or other changes at Bridger Coal Company (BCC), those changes in costs will be reflected in the Energy Balancing Account (EBA) until the next general rate case (GRC) when the changes would be reflected in base rates. The timing of PacifiCorp's next GRC has not been determined and will depend on changes in all cost and revenue categories that are included in the Company's revenue requirement.

(d) As discussed in Sierra Club 4.14, the methodology utilized to determine coal prices for net power cost (NPC) modeling is different than that utilized in the CPCN approval docket for the Bridger 3 & 4 SCR. A comparison of test period costs to the CPCN approval docket for the Bridger 3 & 4 SCR has not been completed. Since the CPCN analysis, Bridger Coal Company mine costs and quality have been updated as part of the annual mine planning process. Test period costs reflect updated drilling, productivity and mine advancement rates. Since the CPCN analysis, some longwall panels have been shortened to avoid sandstone channels and incompetent roof strata while additional panels have been added.

Docket No. UE 374
Exhibit Sierra Club/118
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 118

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Jeremy Fisher

PacifiCorp Dec. 5, 2013 Memorandum

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/119
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 119

HIGHLY CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Jeremy Fisher

Exhibit B Re: Bridger EPC Contract

This exhibit is highly confidential pursuant to Protective Order 20-131 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/120
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 120

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Direct Testimony of Susan Arigoni

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO
* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE HAYDEN EMISSIONS CONTROL PROJECT	**)**	**DOCKET NO. 11A- ____E**

Colorado PUC E-Filings System

DIRECT TESTIMONY AND EXHIBITS OF SUSAN ARIGONI

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

November 14, 2011

LIST OF EXHIBITS

Exhibit No. SA-1	Kinder Morgan Press Release

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE HAYDEN EMISSIONS CONTROL PROJECT	**)**	**DOCKET NO. 11A- ____E**

DIRECT TESTIMONY AND EXHIBITS OF SUSAN ARIGONI

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Susan Arigoni. My business address is 1800 Larimer, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Xcel Energy Services Inc., a wholly owned subsidiary of Xcel Energy Inc., the parent company of Public Service Company of Colorado. My job title is Vice President, Fuels.

Q. WHOM ARE YOU REPRESENTING IN THIS PROCEEDING?

A. I am testifying on behalf of Public Service Company of Colorado ("Public Service" or "Company").

Q. HAVE YOU INCLUDED A DESCRIPTION OF YOUR QUALIFICATIONS, DUTIES AND RESPONSIBILITIES?

A. Yes. A description of my qualifications, duties and responsibilities is included as Attachment A.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe coal-supply issues related to the Hayden Station ("Hayden"), describe how prior forecasts of delivered prices for Hayden were developed, and how prices negotiated in a recent coal purchase for Hayden differ from the forecast.

III. HAYDEN STATION COAL OVERVIEW

Q. PLEASE PROVIDE AN OVERVIEW OF THE COAL REQUIREMENTS FOR HAYDEN.

A. Hayden is a 446 MW, two-unit station that nominally requires about 1.6 million tons per year of coal. The current six-year contract with Peabody for supply to Hayden terminates at the end of 2011. With the resolution of Clean Air Clean Jobs Act ("CACJA") plans and the life extension of the plant as a result of the Commission's approval of Public Service's plans for Hayden, the Company sought to contract for new coal supply beyond 2011 for Hayden.

Public Service jointly owns Hayden with two other utilities: PacifiCorp and Salt River Project Agricultural and Irrigation and Power District ("SRP"). Although Public Service is the Operating Agent for Hayden, major decisions, like coal supply and the installation of emissions controls have been jointly

made by the participants. Therefore, Public Service has worked with SRP and PacifiCorp to negotiate the coal-supply arrangements for Hayden.

Q. BRIEFLY SUMMARIZE HISTORIC COAL PROCUREMENT FOR HAYDEN.

A. Hayden has had most of its coal supplied over the years from nearby mines. For most of the plant's life, coal was supplied from the Seneca Mine. Since that mine closed, Hayden has been supplied from Peabody Energy's Twentymile coal mine operations ("Twentymile"). Twentymile and the Seneca Mine before it are quite close to Hayden, which has provided a logical and synergistic relationship between the coal mines and Hayden.

IV. HAYDEN COAL COSTS

Q. WHAT ASSUMPTIONS REGARDING COAL AVAILABILITY AND COSTS FOR HAYDEN WERE OF PARTICULAR IMPORTANCE IN THE CACJA ANALYSIS?

A. Coal costs utilized in scenarios for the CACJA plan were developed in early to mid 2010. The focus was on Colorado coal because the primary plants that are part of the CACJA plan burn Colorado coal. Relative to Montana and Wyoming Powder River Basin ("PRB") coal production, the volume of Colorado coal production is small (25 million tons v. 473 million tons in 2010).

Public Service plants burning Colorado coal are primarily served (and entirely served in the case of Hayden) with coal from Twentymile, and that mine was expected to be played out sometime in 2013. In 2010, Peabody was evaluating opening a new mine ("Sage Creek"), but had not yet committed to opening it. Another area coal mine, Rio Tinto's Colowyo Mine,

was for sale, and Rio Tinto had announced it did not intend to expand production at that mine after current reserves are exhausted in 2017.

Twentymile is 27 miles by rail from Hayden, and Colowyo is 40 miles by rail from Hayden, making those mines the most economic options for coal supply to the plant. Other coal mines in Colorado that could supply Hayden are located in the North Fork Valley, which is southwest of Glenwood Springs and more than 326 miles by rail to Hayden.

North Fork Valley mines include Arch Coal's West Elk Mine, which produced approximately 5 million tons in 2010, and Oxbow's Elk Creek Mine, which produced 4 million tons in 2010. Coal from both of those mines has been purchased in the past for Cherokee and Valmont stations, but not for Hayden. Twentymile and the North Fork Valley mines (including West Elk and Elk Creek) are underground mines.

Scenarios developed for CACJA included various quantity reductions of coal for Cherokee and Valmont. All CACJA scenarios had Hayden running on Colorado coal with the installation of selective catalytic reduction devices ("SCRs") on both units. The base case assumed Cherokee and Valmont would continue on coal with the installation of emission controls necessary to achieve required NOx-emissions reductions. Thus, the base case assumed no change to demand for Colorado coal. However, the case that was approved by the Commission includes the cessation of coal use by the end of 2017 by the Cherokee and Valmont units.

Q. WERE ANY SPECIAL STUDIES PERFORMED TO ESTIMATE COAL

COSTS FOR THE CACJA ANALYSIS PERFORMED BY PUBLIC SERVICE?

A. Yes. Wood Mackenzie, a research and consulting company under retainer to Public Service, was asked to do a study to assess the effect of reduced demand on the price of Colorado coal. That study was completed in June 2010 and was included as an exhibit in the direct testimony of Tim Sheesley in the CACJA plan filing with the Commission in August 2010.

Q. IS THAT STUDY STILL RELEVENT?

A. Yes. It is important for the Commission to understand the methodology and scope of the study to put in perspective the reasonableness of the continued operation of Hayden on coal and the installation of SCRs at Hayden 1 and 2.

Q. PLEASE SUMMARIZE THE METHODOLOGY USED BY WOOD MACKENZIE TO PREDICT COAL PRICES IN THIS SPECIAL STUDY.

A. For forecasting coal prices, Wood Mackenzie used its proprietary linear programming model to develop a base forecast from which it can make adjustments for current market conditions and run scenarios around that adjusted output. For the special study, Wood Mackenzie used its adjusted forecast for Colorado coal and ran scenarios based on various reductions in Colorado coal demand caused by the retirement of Public Service's different coal plants. The reduced demand curves were compared to Wood Mackenzie's proprietary cost (supply) curve to derive new forecast prices, which were lower because mines with costs lower on the cost curve set the market-clearing price. The primary impact was on lower-heat-content

Colorado coals, which are the Colorado coals Public Service primarily buys.

Q. HOW WERE THE SCENARIOS DEVELOPED FOR THE CACJA ANALYSIS USED BY WOOD MACKENZIE?

A. The scenarios developed for modeling in the CACJA plan were used by Wood Mackenzie in its model, and the coal prices derived by the model were used in the CACJA model runs. Coal cost for Hayden was the price derived by the Wood Mackenzie model.

The Wood Mackenzie study covered the period 2010-2018 and covered the effect of reduced demand on price. The demand reduction associated with the elimination of Cherokee and Valmont demand was established at ~2 million tons.

Uncertainty about Peabody's decision to continue production after the Twentymile reserves were anticipated to be exhausted and the uncertain future of the Colowyo mine, owned by Rio Tinto, was recognized in the study. However, the base case assumed Twentymile capacity would be replaced by the Sage Creek Mine.

Q. HOW DID THE MODEL RESULTS REFLECT THE DEMAND REDUCTION?

A. The model predicted that with a demand reduction of ~2 million tons magnitude, a price reduction of $8-$15/ton could be expected if the mine and its replacement capacity were to continue to operate. Prices are market clearing prices and are estimates of prices for one-year contract sales. In the model, market clearing prices are limited on the low side to the price at which continued operation of the mine is unprofitable.

Q. HOW WERE PRICES DERIVED BEYOND 2018 FOR MODELING IN THE CACJA STUDIES PERFORMED BY PUBLIC SERVICE?

A. Since Wood Mackenzie's study only went through 2018, prices for Hayden beyond then were escalated from the 2018 price for the life of the plant in Public Service's Strategist modeling.

Q. WHAT ABOUT TRANSPORTATION COSTS?

A. Transportation costs for Hayden were estimated assuming rail delivery of coal beginning in 2012. However, a contract for rail had yet to be negotiated with the Union Pacific Railroad ("UP"), the only rail-delivery option available for the Plant.

Q. WHEN YOU BEGAN SEEKING A REPLACEMENT SUPPLY FOR THE EXPIRING PEABODY CONTRACT FOR HAYDEN, WHAT WERE YOUR KEY CONSIDERATIONS?

A. Reliable long-term supply and delivered price were identified as the two most important attributes of a supply agreement. Because supply of Colorado coal is limited for Hayden and with the CACJA-approved plan for Hayden resulting in a long life for the plant, we ranked long-term supply as the number one priority.

Q. HOW DID YOU ASSESS THE MARKET FOR COAL FOR HAYDEN?

A. Public Service recognized the primary source of Colorado coal for Hayden was likely to be Twentymile because it is significantly closer to Hayden than the closest other mine with available coal (27 miles by rail versus 326 miles by rail); therefore, the transportation costs are much lower. The practical

result is that competing coals would have to be significantly lower priced on a free-on-board ("FOB") mine basis to compete with Twentymile.

With limited supply options for Hayden, a primary focus early on was to exhaust all possible supply options besides Peabody. Colowyo, owned by Rio Tinto, is the best alternative because it is the only alternative with proximity to Hayden nearly equivalent to Peabody's. Colowyo production is sold out through 2017, and production beyond that time will require development of additional reserves. Rio Tinto was contacted with the idea of discussing a coal purchase post 2017. However, Rio Tinto was not interested in operating the mine after 2017 and investing the capital required to develop additional reserves. Even if Rio Tinto had been interested, Hayden would still have a gap in supply of three or four years from 2012 until 2015 or 2016.

With no immediate prospects for Colowyo assets being sold to an entity willing to invest the capital necessary to develop additional reserves, it was clear Colowyo could not be considered a long-term prospect. Even if Colowyo were to be sold, it will take at least two years from the closing of that transaction for Colowyo to ramp up production from 2.3m tons per year.

Q. WHAT SUPPLY OPTIONS WERE AVAILABLE AND HOW DID YOU OBTAIN PROPOSALS FROM SUPPLIERS?

A. Despite the inherent economic advantage the short transportation distance creates for Twentymile, Public Service solicited proposals for coal supply in the market in January 2011. The combination of responses from coal suppliers and the rail pricing indicated Peabody was the lowest priced option,

but negotiations over the ensuing months brought the coal pricing down even lower.

Q. WERE THERE UNUSUAL CHALLENGES PARTICULAR TO THE HAYDEN PLANT THAT HAD TO BE ADDRESSED IN OBTAINING A RELIABLE, LONG-TERM COAL SUPPLY?

A. Yes. Peabody reserves at Twentymile will be exhausted at about the end of 2014. However, Peabody has adjacent reserves, called Sage Creek, it is willing to develop but only if it gets a long-term coal sales contract that underpins the significant investment it would take to open those new reserves.

The Peabody interests of developing a structure for a long-term contract that would underpin Sage Creek development align with Public Service's need for a long-term, reliable supply to support the long-term operation of the plant. Public Service was able to balance its lack of competitive options with Peabody's interests to achieve a transaction that provides a long-term supply for Hayden.

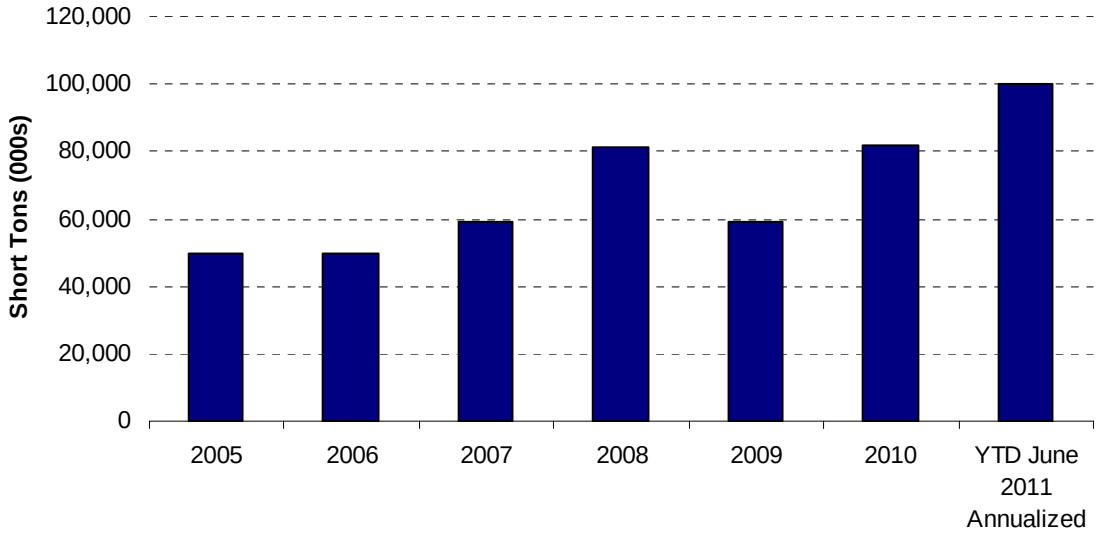
Q. WERE THERE DEVELOPMENTS IN THE COAL MARKET THAT WERE UNKNOWN OR UNEXPECTED BACK IN 2010 WHEN COAL PRICES FOR CACJA ANALYSIS WERE ESTIMATED?

A. Demand for Colorado coal in domestic markets has continued to be weak. However, producers of Colorado coal, including Peabody, have taken and continue to take steps to export coal in seaborne markets as global coal markets continue to grow. The export demand was not anticipated back in

early 2010 but it has influenced the price of coal marketed to US customers, including the price negotiated with Peabody for Hayden supply.

The US Energy Information Administration ("EIA") reported 81.7 million short tons of exports in 2010, and preliminary exports for the first half of 2011 total 53.6 million short tons. The following chart, based on EIA data, shows the growth in US coal exports in recent years, as interrupted by the world-wide recession in 2008-9.

US Coal Exports (Metallurgical and Steam Coals)



As shown by the above chart, 2011 US coal exports could be near 100m tons in 2011. The totals in the chart included both metallurgical and steam coals; however, much of the US coal with coking properties for use in making steel would have been sold in the US as steam coal but for the high seaborne market prices for metallurgical coals.

Colorado producers have found opportunities for exports of Colorado coal – primarily through the Gulf of Mexico. As an example of the steps being

taken to export Colorado coal, Kinder Morgan announced in the spring of 2011 it will invest $18 million in its Port of Houston facility to export 2.2 million tons per year of Colorado coal (see Exhibit No. SA-1 for Kinder Morgan press release). With seaborne market prices delivered to Europe consistently above $110 per metric tonne this year, netback prices are attractive to Colorado producers.

It is too early to tell how many tons in total of Colorado coal are being exported, but all the Colorado producers who actively participate in markets for coal are doing it or considering it.

Q. PLEASE COMPARE THE DELIVERED COAL COSTS ACHIEVED WITH THE PEABODY CONTRACT TO THOSE WOOD MACKENZIE DERIVED IN THEIR MODELING.

A. The negotiated delivered cost on a $/MMBtu basis (FOB mine coal cost plus rail transportation) is higher than the Wood Mackenzie forecast prepared in early 2010. This increase is due primarily to assumptions relating to reduced demand causing price reduction not proving out. In fact, as described above, global demand for Colorado coal has created a new market for Colorado coal that was not anticipated by Wood Mackenzie. None of the events causing a reduction in demand in Wood Mackenzie's model (the elimination of demand from Cherokee and Valmont) has occurred yet, so market prices have not adjusted to those events.

	$/MMBtu	
Year	Wood Mackenzie Forecast	Negotiated Prices
2012	$1.92	$2.19
2013	1.96	2.23
2014	2.02	2.31
2015	1.85	2.36
2016	1.89	2.40
2017	1.98	2.48
2018	1.50	2.53
2019		2.57
2020		2.66
2021		2.71
2022		2.76
2023		2.80
2024		2.85
2025		2.90
2026		2.95
2027		3.01

Q. DOES THIS CONTRACT FULFILL PUBLIC SERVICE'S OBJECTIVES OF SECURING LONG-TERM COAL SUPPLY AT REASONABLE COST SUPPLY FOR HAYDEN?

A. Yes. While the above prices are higher than the Wood Mackenzie forecast, they reflect real market conditions. The contract provides Public Service with a supply of coal to Hayden at least though 2019. The prices for the coal result in a reasonable cost of coal supply for Hayden.

V. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company has agreed to a long-term coal supply for Hayden to support the continued operation of the plant after the SCRs are installed to ensure the value of that investment is protected.

I have outlined the coal supply procurement process related to Hayden and the particular issues associated with supply options. Prior forecasts of costs used for the CACJA Plan are explained and compared to the current negotiated coal-supply agreement for the station.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

Attachment A

Statement of Qualifications

Susan Arigoni

I have a Bachelor of Arts degree from Duquesne University and an MBA in Finance from Regis University.

I began my career at Public Service in 1983 as a Financial Analyst in Corporate Finance. I have held various management positions including, Manager, Gas Transportation 1989-1992, Gas Rates Director 1992-1994, Director of Gas Planning, Marketing and Supply 1994-1998, Vice President, Planning and Budgeting for transmission and distribution operations from 1998 to 2000, and Vice President Asset Management for the generation business unit 2000-2006. In 2006, I assumed my current responsibilities as Vice President Fuels. In that position I am responsible for acquiring coal and coal transportation, natural gas and gas transportation and storage for all of Xcel Energy's electric operations and gas LDCs.

I have provided expert and policy testimony before the Colorado Public Utilities Commission and the Federal Energy Regulatory Commission.

Docket No. UE 374
Exhibit Sierra Club/121
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 121

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Jeremy Fisher

Review of

Existing Analysis on Craig and Hayden Environmental Investments

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/122
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 122

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Jeremy Fisher

Attachment to PacifiCorp Response to SC Data Request 2.6-2

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/123
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 123

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Jeremy Fisher

Hayden SCR Recommendation Memo

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/124
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 124

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Jeremy Fisher

Attachment to PacifiCorp Response to SC Data Request 2.4

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/125
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 125

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

Direct Testimony of James Hill

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF COMMISSION CONSIDERATION OF PUBLIC SERVICE COMPANY OF COLORADO PLAN IN COMPLIANCE WITH HOUSE BILL 10-1365, "CLEAN AIR-CLEAN JOBS ACT."	)))))	DOCKET NO. 10M-245E

DIRECT TESTIMONY AND EXHIBITS OF JAMES F. HILL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

August 13, 2010

Submitted to Colorado PUC E-Filings System

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO
* * * * *

IN THE MATTER OF COMMISSION CONSIDERATION OF PUBLIC SERVICE COMPANY OF COLORADO PLAN IN COMPLIANCE WITH HOUSE BILL 10-1365, "CLEAN AIR-CLEAN JOBS ACT."	)))))	**DOCKET NO. 10M-245E**

DIRECT TESTIMONY AND EXHIBITS OF JAMES F. HILL

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James F. Hill. My business address is 1800 Larimer, Suite 1400, Denver, CO 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc., a wholly-owned subsidiary of Xcel Energy Inc., the parent company of Public Service Company of Colorado. My job title is Director of Resource Planning and Bidding - Colorado.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Public Service Company of Colorado ("Public Service" or the "Company").

Q. HAVE YOU INCLUDED A DESCRIPTION OF YOUR QUALIFICATIONS, DUTIES, AND RESPONSIBILITIES?

A. Yes. A description of my qualifications, duties, and responsibilities is included as Attachment A.

Q. WERE YOU INVOLVED IN THE DEVELOPMENT OF THE COMPANY'S EMISSIONS REDUCTION PLAN?

A. Yes, I was.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to provide a general overview of how the Company developed its emission reduction plan and how the various scenarios that were evaluated as part of this plan meet the analysis requirements of the Clean Air – Clean Jobs Act ("CACJA" or "Act"), including the requirement to achieve at least a 70% reduction in NO_x emissions. I also discuss how the various scenarios were modeled in the Strategist computer model and briefly discuss some of the key results of those analyses.

II. Plan Development

Q. PLEASE PROVIDE A GENERAL OVERVIEW OF THE PROCESS THE COMPANY EMPLOYED IN DEVELOPING THE VARIOUS SCENARIOS THAT WERE EXAMINED IN THE EMISSION REDUCTION PLAN.

A. In general we first identified which Company coal-fired generation units would be included in the plan for either new emission controls or retirement[1] and then developed various combinations (referred to herein

[1] In the context of this emission reduction plan, the term "retirement" is used to describe a coal unit that is either shutdown and no longer used to generate electricity or, a coal unit that continues to generate electricity but is fueled with natural gas (i.e., the unit is never again operated on coal).

as "scenarios") of retirements and emission controls that would both meet the requirements of the legislation and evaluate a range of different coal plant retirement options. Next we assessed which existing generation sites might accommodate additional gas-fired generation technologies that could act to replace the coal-fired generation capacity that is retired. Sites considered for these replacement gas-fired facilities included Cherokee, Valmont, Arapahoe, Fort St. Vrain, Rocky Mountain Energy Center, and Blue Spruce Energy Center. The permitting requirements as well as gas and electrical infrastructure needed to deliver power from those sites were also assessed.

Having identified the scenarios and existing sites that could accommodate new gas-fired generation technologies, we developed various portfolios of generation technologies that could provide replacement generation capacity for the coal-fired generation retired in each scenario while maintaining an acceptable level of reliability on the transmission system.

The impacts of additional DSM, low emitting generation technologies such as solar and wind, and certain IPP facilities were then examined through various add-on (termed "bolt-on" options herein) or sensitivity analyses.

Q. WHAT COAL-FIRED GENERATION UNITS WERE IDENTIFIED FOR INCLUSION IN THE PLAN?

A. Table JFH-1 provides summary information on the Company coal fired generation units included in the emission reduction plan and the actions (retirement or new emission controls) to be evaluated for each unit.

Table JFH-1

						Action Considered	
Plant	**Location**	**MW**	**Age**	**BART Unit**	**Reasonable Progress**	**Retire**	**Emission Controls**
Arapahoe 3	Den Metro	45	59			Yes	
Arapahoe 4	Den Metro	111	55			Yes	
Cherokee 1	Den Metro	107	53		Yes	Yes	Yes
Cherokee 2	Den Metro	106	51		Yes	Yes	Yes
Cherokee 3	Den Metro	152	48		Yes	Yes	Yes
Cherokee 4	Den Metro	352	42	Yes		Yes	Yes
Hayden 1 [1]	NW Colo	139	45	Yes			Yes
Hayden 2 [1]	NW Colo	98	34	Yes			Yes
Pawnee	NE Colo	505	29	Yes		(2)	Yes
Valmont 5	Boulder	186	46	Yes		Yes	Yes
				Total MW		**903**	**1645**

Notes:
(1) Public Service ownership shown (75.5% of Hayden 1, 37.4% of Hayden 2)
(2) As discussed later in the Plan, Pawnee retirement was analyzed as a "bolt on" option.

Q. SINCE ARAPAHOE 3 AND 4 WERE ALREADY SCHEDULED TO BE RETIRED PRIOR TO DECEMBER 31, 2015, WHY ARE THEY IDENTIFIED IN TABLE JFH-1 AS BEING PART OF THE EMISSION REDUCTION PLAN?

A. While Arapahoe 3 and 4 can not be counted towards the 900 MW target for plant retirements or the 70% to 80% NO_x emission reduction requirements per the CACJA, they can count towards the legislative provisions of the Act regarding advancing the retirement dates of coal units that had previously been announced. Just how far the Arapahoe 3 and 4 unit retirement dates can be advanced is impacted by the fact that the Arapahoe plant coal transportation agreement requires Public Service

to nominate and transport a minimum of 500,000 tons annually through 2013. Failure to comply with this minimum tonnage amount could result in Public Service having to pay liquidated damages under the contract. In the analysis of this emission reduction plan, the Company selected a retirement date of late 2013 for Arapahoe 3 and January 2014 for Arapahoe 4.

Q. TABLE JFH-1 IDENTIFIES PAWNEE AND HAYDEN BEING CONSIDERED FOR EMISSION CONTROLS. CAN YOU DESCRIBE THE GENERAL ISSUES WITH THESE PLANTS?

A. Yes. As described in the testimony of Company witness Gary Magno, Hayden units 1 and 2 are included in the plan contingent upon the final outcome of ongoing state air quality planning processes being conducted by the Air Quality Control. Mr. Magno also discusses how the Pawnee plant will be required to install emission controls in the near future for both NO_x and SO_2 to comply with federal requirements. Therefore, they are considered affected plants under CACJA based on reasonably foreseeable requirements.

Q. WHAT COMBINATIONS OF RETIREMENTS AND EMISSION CONTROLS WERE DEVELOPED FOR THE COAL UNITS IDENTIFIED IN TABLE JFH-1?

A. Table JFH-2 summarizes the various scenarios developed for analysis in the plan from these coal-fired units.

Table JFH-2

	Scenarios								
Plant	Benchmark 1	Benchmark 1.1	2	3	4	5	6	6.1	7
Cherokee 1	SNCR 2014	SNCR 2014	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011
Cherokee 2	SNCR 2014	SNCR 2014	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011
Cherokee 3	SCR 2017	SCR 2017	SCR 2017	Shutdown 2017	SCR 2017	Shutdown 2017	Shutdown 2015	Shutdown 2017	Fuel Switch 2014 Shutdown 2015
Cherokee 4	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	**Shutdown 2018**	SNCR 2012 **Shutdown 2022**	Fuel Switch 2014 **Shutdown 2018**
Valmont 5	SCR 2015	SCR 2015	SCR 2015	SCR 2015	Shutdown 2017	Shutdown 2017	Shutdown 2017	Shutdown 2017	Fuel Switch 2013 Shutdown 2017
Pawnee [1]	SCR 2014	---	SCR 2014	SCR 2014	SCR 2014	SCR 2014	SCR 2014	SCR 2014	SCR 2014
Hayden 1 [1]	SCR 2015	---	SCR 2015	SCR 2015	SCR 2015	SCR 2015	SCR 2015	SCR 2015	SCR 2015
Hayden 2 [1]	SCR 2016	---	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016
Retired MW Controlled MW	0 1645	0 903	213 1432	365 1280	399 1246	551 1094	903 742	903 742	903 742
Total MW	**1645**	**903**	**1645**	**1645**	**1645**	**1645**	**1645**	**1645**	**1645**
% NOx reduction 2018[3]	72%	70%	81%	83%	83%	85%	69%	76%	84%
% Nox reduction when all actions complete[3]	72%	70%	81%	83%	83%	85%	89%	89%	89%
End of Year Convention => Action occurs at end of year listed									

Notes:
(1) Analyses also performed with no emission controls on Pawnee or Hayden
(2) Actions in Bold font occur beyond December 31, 2017
(3) Low NOx burner upgrades on Cherokee 2 and 4, Hayden 1 and 2, Pawnee 1 and Valmont 5 are included in the NOx reductions.

Not shown in Table JFH-2 are plans to retire both Arapahoe 3 and Arapahoe 4 from burning coal at the end of 2013, two years earlier than the December 31, 2015 deadline previously announced.

Q. HOW WERE THE % NO_x REDUCTIONS IN TABLE JFH-2 DETERMINED?

A. First, engineering estimates were used to determine the NO_x emission rates (lb/MMBtu) for each facility after completion of each action (e.g., installation of emission controls). These post-action NO_x rates were then

multiplied by each unit's heat rate (btu/kWh) and then by each unit's expected kWh level of annual generation to produce an estimate of the annual tons of NO_x that would be emitted after implementation of each action. Per requirements of the CACJA (Section 40-3.2-205), the annual tons of NO_x emitted by the replacement gas-fired generating units (assumed to be combined cycle units) were also included to arrive at the final net annual tons of NO_x that would be emitted as a result of the combined effect of the control/retirement actions and replacement actions. This final value for the annual tons of NO_x emitted was compared to the actual amount of NO_x emitted in 2008 from the same group of coal units and the resulting % reduction listed in Table JFH-2. Two NO_x reduction estimates are provided in Table JFH-2, one for year 2018 and the other for when all actions in the plan that occur beyond 2018 are completed. Additional details on the NO_x reductions estimates for each scenario are contained in Appendix 2 of Exhibit KTH-2.

Q. WERE % NO_x REDUCTIONS SIMILAR TO THOSE IN TABLE JFH-2 ALSO CALCULATED THROUGH MODELING OF SCENARIOS IN THE STRATEGIST COMPUTER MODEL?

A. Yes. The estimated % NO_x reductions in Table JFH-2 were only used in the screening process to assess the feasibility of scenarios that would later be evaluated in detail within the Strategist model. Section 8 of Exhibit KTH-2 contains Strategist modeling results for the various

scenarios including the % NO_x reduction calculated in Strategist. These Strategist NOx reduction estimates are summarized later in my testimony.

Q. DO THE % NO_x REDUCTIONS IN TABLE JFH-2 ACCOUNT FOR THE POSSIBILITY OF SOME IPP GAS UNITS IN THE METRO AREA SELLING THEIR OUTPUT TO ANOTHER UTILITY?

A. No. They only reflect the Public Service owned units (both coal units and a replacement gas units) that are included in the various scenarios. As discussed in the testimony of Company witness Gary Magno, the metro area IPP units at issue have no significant effect on the level of NO_x reductions contemplated by the various scenarios considered in this plan.

Q. HOW DO THESE TABLE JFH-2 SCENARIOS COMPLY WITH THE ANALYSIS REQUIREMENTS OF THE CACJA?

A. As discussed in the testimony of Karen Hyde, CACJA requires utilities include in their emission reduction plan an evaluation of the following three scenarios:

1. A scenario that incorporates emission controls on at least 900 MW of existing coal units to produce at least a 70% to 80% reduction in annual emissions of NO_x from the units chosen to be in the plan;
2. A scenario that retires a minimum of 900 MW of coal units by January 1, 2015 and repowers or replaces the unit's capacity with gas units or other low emitting resources, including energy efficiency. This analysis cannot include Arapahoe 3 and 4 in the

900 MW because Public Service had already announced the retirement of these units prior to the passage of CACJA; and

3. A scenario that retires some amount of coal units by January 1, 2013 or advances the date when previously announced retirements would occur (this alternative can consider advancing the retirement date of Arapahoe 3 and 4).

Item 1 above is addressed by the two benchmark scenarios which analyze the emission and cost impacts of adding emission controls to the coal units considered in the Plan. Item 2 is addressed in scenario 7 which halts or retires coal operations at Cherokee units 1, 2, 3, and 4 and Valmont 5 (903 MW) by either shutting down the units or by fuel switching to natural gas by January 1, 2015. And item 3 is addressed in scenarios 2 through 7 by the retirement of Cherokee units 1 and 2 prior to January 1, 2013 and, while not shown in Table JFH-2, by advancing the retirements of Arapahoe 3 and 4 approximately two years from December 31, 2015.

Q. PLEASE SUMMARIZE THE PROCESS BY WHICH THE COMPANY DEVELOPED PORTFOLIOS OF NEW GENERATING FACILITIES TO REPLACE ANY COAL-FIRED GENERATION CAPACITY THAT WAS SHUTDOWN IN EACH SCENARIO.

A. Two primary criteria were used to build portfolios of resources to replace the retired coal-fired generation for each scenario: 1) match the level of replacement generation with the level of retired coal generation as close as possible, taking into account the efficiency of certain unit designs and

sizes; and 2) maintain sufficient generation redundancy at the Cherokee site that is needed to ensure continued reliable operation of the Denver-Metro area transmission system. Company witness Teresa Mogensen discusses the level of generation needed for transmission reliability in her direct testimony. The result of the second criteria was that although other generation sites were considered for replacement capacity, engineering judgment and operational experience dictated that we focus on siting replacement capacity at Cherokee in order to provide the voltage support and power generation necessary to maintain transmission system reliability when Denver-Metro area coal units are shutdown. The different portfolios of replacement generation that resulted from this process are identified in Table 5.5 of Exhibit KTH-2.

III. Scenario Analysis

Q. HOW WERE THE OVERALL SYSTEM COSTS AND EMISSION IMPACTS OF THE VARIOUS SCENARIOS DETERMINED?

A. Estimates were first developed for 1) the costs to retire coal plants (both shutdown and fuel switch), 2) the costs to construct and maintain new emission controls as well as the NO_x removal efficiency of those controls, and 3) the costs to construct and maintain replacement generation facilities along with the performance characteristics of those facilities. Specifics about these estimates are addressed in the testimony of Company witness Greg Ford.

The cost and performance estimates were then modeled in the Strategist electric system planning model along with the existing power supply system, a forecast of future generation additions, and a forecast of future customer load. The model was run for the period from 2010-2046 and various model outputs for items such as total system costs, fuel costs, fuel burn volumes, emission levels, etc. were collected for each scenario and compared to the Benchmark 1 scenario (in which emission controls are added to all coal units included in the plan). Comparisons were also made between Benchmark 1.1 and the various bolt-on scenarios that did not include controls on Pawnee or Hayden.

Q. CAN YOU BRIEFLY DESCRIBE THE STRATEGIST MODEL?

A. Strategist is a computer based model specifically designed to represent the many characteristics of an electric utility's power supply system and to simulate economic dispatch of the generating resources in that system to meet customer demand for electric power (a.k.a., load) in the lowest cost manner. The model also has the capability to determine the least-cost mix of generation resources that should be added to an electric system to help serve future load growth on the system. PSCo has used Strategist in developing our last three resource plans submitted to the Commission. Strategist incorporates a wide range of variables that can be used to represent various types of electric generating facilities (i.e., coal-fired generators, gas-fired generators, wind and solar generators to name a few). Strategist contains four basic modules ("LFA", "GAF", "CER",

"PROVIEW") that work in concert to simulate the operation of the existing utility generating units as well as the new generating units that are added to the system in future years to meet load growth. The model tracks and reports capital costs (and the associated revenue requirements), operations and maintenance costs (O&M), fuel costs, emissions of SO_2, NO_x, CO_2, and Hg, along with any costs associated with these emissions.

Q. PLEASE PROVIDE A SUMMARY OVERVIEW OF HOW EACH OF THE MAJOR SCENARIO COMPONENTS WAS REPRESENTED IN THE STRATEGIST MODELING OF SCENARIOS.

A. Coal Retirements – Fuel Switching Coal Units to Gas: Estimates for the variable and fixed O&M costs including ongoing capital expenditures, for coal units considered for fuel switching to natural gas in the plan were developed and included in the model. The O&M and ongoing capital costs estimates for fuel switching were significantly less than those for continued operation on coal. On-going capital costs were converted to a revenue requirement stream over the remaining book life of the unit[2].

In addition, the coal unit fuel source was switched to gas and the lower emission rates and lower efficiency (i.e., higher heat rate) for operation on gas were all modeled.

Coal Retirements - Shutting Units Down: Estimates of the variable and fixed O&M costs, including ongoing capital expenditures for the remaining life of each coal unit being considered for early shutdown in the plan, were

[2] The main components of capital revenue requirements are depreciation, earnings, and taxes.

developed on a plant by plant basis for the specific shutdown date and were included in the model. On-going capital costs were converted to a revenue requirement stream over the shortened book life of the unit as a result of early retirement. Given this shortened remaining life of the coal unit, the O&M and ongoing capital costs for early retirement were less than those for continued operation on coal. The remaining book value as well as the estimated decommissioning/dismantlement costs for these coal units were converted to a revenue requirement stream over the remaining life of the units. Decommissioning costs were developed by TLG Services in a study completed in 2007 and adjusted for site pond closure costs which were not included in the original study.

New Emission Controls: Estimates for both the capital cost to install NO_x, SO_2, and Hg controls as well as the operation and maintenance costs for the controls were developed specifically for each coal unit. The capital costs to install the control equipment were converted to a revenue requirement stream over the estimated book life of the emission control equipment (10-years for SNCR and 15-years for SCR) using an authorized return on equity of 10.5% and an after tax WACC of 7.609%. Construction work in progress (CWIP) was modeled in lieu of AFUDC. Estimates of NO_x controls capital costs varied over a wide range depending on the specific configuration of the different coal plants. Details about these estimates are included in the testimony of Company witness Greg Ford.

Impacts of Emission Controls on NO_x Emission Levels: NO_x emission rates for each coal unit were modeled in units of lbs/MMBtu of fuel burned. A single lb/MMBtu NO_x rate was modeled for each coal unit based on the actual NO_x emissions from that unit in past years as measured by continuous emission monitoring (CEMS) equipment installed at the plant. When the unit's output level is either raised or lowered in the Strategist model through the economic dispatch process, the amount of NO_x emitted from the unit for each MWh of power produced changes as a function of the MMBtu of fuel burned to produce that MWh (the units are modeled with a heat rate curve where the amount of fuel burned for each MWh generated changes depending on the output level of the unit). When modeling the installation of new emission controls on the coal units, the resulting NO_x emission rate was reduced by an amount represented by the percent removal or to an emission rate representative of the capability of the control equipment installed. For example, if a coal unit with a NO_x emission rate of 0.33 lbs/MMBtu (prior to the installation of controls) were to be equipped with NO_x controls capable of a 30% removal efficiency (in the case of an SNCR), the resulting NO_x rate would be 0.23 lbs/MMBtu (0.33 – [0.3x0.33] = 0.23).

Replacement Generating Facilities:

New Self-Build Generation: Site specific estimates (as opposed to generic estimates) were developed for the capital costs to construct as well as the cost to operate and maintain (including ongoing capital

expenditures) three different gas-fired facilities located at the Cherokee site - a simple cycle peaking facility, a 1x1 combined cycle, and a 2x1 combined cycle. Similarly, site specific estimates were developed for a conversion of Fort St. Vrain units 5 and 6 to combined cycle. Additional details about these estimates are included in the testimony of Company witness Greg Ford. The capital costs to construct these gas-fired generating facilities were converted to a revenue requirement stream over the book life of the facility using an authorized return on equity of 10.5% and an after tax WACC of 7.609%. Construction work in progress (CWIP) was modeled in lieu of AFUDC.

Low Emitting Generation: The generic cost estimates identified on Table 6.2 of Exhibit KTH-2 were used to represent any new wind, solar PV, and solar thermal w/storage resources that were included in the analysis of scenarios. Cost and performance information for pumped storage technologies were modeled consistent with bid data provided by the developer of a pumped storage facility in response to PSCo's 2009 All-Source RFP for a power purchase agreement.

Existing IPP Gas-fired Generation: Five existing gas-fired generation facilities - Thermo Monfort in Greeley, Thermo Power and Electric in Greeley, Southwest Generation (SWG) at Valmont, SWG at Arapahoe, and SWG at Fountain Valley – have purchase power agreements (PPA) with PSCo that expire prior to 2018. In developing the emission reduction plan, the owners of these generators provided PSCo with a

sale price for each of these facilities for consideration in the plan. In modeling these facilities, the owner-supplied sale price was converted to a revenue requirement stream over the estimated remaining useful life of each facility using an authorized return on equity of 10.5% and an after tax WACC of 7.609%. Ongoing O&M and capital expenditures that Public Service would incur if it were to own the units were estimated and included in the overall modeling of costs for these facilities.

Increased Utilization of Existing Gas-fired Generators: The system cost and system emission impacts resulting from any increased utilization of the five existing IPP facilities mentioned above is embedded within the Strategist modeling of scenarios in which any of these five units were included[3]. Similarly, the cost and emission impacts associated with any increased utilization of existing Company owned gas-fired facilities or IPP facilities, whose current contracts extend beyond 2018, are embedded within the Strategist modeling results for the various scenarios. Any increase or decrease in generation from gas-fired generators shows up in the overall system fuel costs and emissions. Changes in the utilization of existing gas-fired generators for each scenario are specifically identified in Section 8 of Exhibit KTH-2.

New Gas Supply Pipeline: The costs associated with a new gas supply pipeline that would be needed to supply gas to the Cherokee site for either fuel switching one or more of the coal units to gas or, for providing gas

[3] See Appendix 9 of Exhibit KTH-2 for a road map of the various model runs that were performed.

supply to new gas fired generators, were represented as an annual fixed charge reflective of what that the gas department of the Company and the upstream interstate pipeline (CIG) would charge the electric department of the Company for such additional fuel supply infrastructure and services. The existing gas infrastructure supplying the Arapahoe site is sufficient to provide firm service to both Arapahoe 4 operating on gas and the SWG Arapahoe facility.

Long Term Gas Supply Contracts: In May 2010 PSCo issued an RFP seeking long term gas supply contracts for a period up to 10-years with the expectation that the winning contract(s) would be used to serve some or all of the incremental gas burns for electric production (i.e., the additional gas burned for the scenario each year versus the level burned in the Benchmark scenario) that result from the emission reduction plan that is ultimately implemented by the Company. The effect of these long term gas contract(s) on the overall fuel costs of each scenario were determined as follows: 1) first the incremental gas burns for each year of the study period were determined for each scenario, by running the scenario in the Strategist model using the base gas price forecast; 2) next the incremental gas burn relative to the gas burns from the Benchmark scenario was calculated for each scenario; 3) the annual cost delta between the base gas price forecast and the winning gas contract(s) was multiplied by the lesser of the annual MMBtu of incremental fuel burn or, the maximum annual MMBbtu offered in the gas contract(s), to produce an

annual dollar impact of the gas contract(s); and 4) the overall annual fuel costs produced from the Strategist run of each scenario were adjusted by the annual dollar impact. These annual cost adjustments were performed outside the Strategist run and are included in all scenarios costs reported in Exhibit KTH-2.

For example, assume when Scenario X was run through the Strategist model, 1,000,000 MMBtu more gas was burned each year compared to that burned in the Benchmark scenario. Also assume that the winning long term gas contract(s) were $1.00/MMBtu lower cost each year than the gas price contained in the base gas price forecast. Under this hypothetical, the overall annual cost for Scenario X would be reduced by $1 million each year.

Increased Utilization of DSM: DSM resources were represented as reductions in annual energy and peak demand along with the estimated program costs needed to achieve those reductions. DSM program costs were modeled as an expense, occurring in the same year as the program expenditures.

Transmission Upgrade Costs: Site specific estimates of the capital costs to construct transmission interconnection facilities and system upgrades were developed for each scenario. These capital cost estimates were converted to a revenue requirement stream over the book life of the facilities using an authorized return on equity of 10.5% and an after tax

WACC of 7.609%. Additional information about these costs is included in Table 5.4 of Exhibit KTH-2.

Q. EXACTLY HOW DID THE STRATEGIST MODELING ACCOUNT FOR THE VARIOUS INTERACTIONS BETWEEN ALL THE DIFFERENT COMPONENTS WITHIN A PARTICULAR SCENARIO?

A. Basically, the various costs discussed above can be grouped into two categories fixed costs and variable costs. Fixed costs are costs that are incurred regardless of how much a power plant operates or how often a piece of equipment (such as emission controls or a transmission line) is utilized. Examples of fixed costs are: capital costs to construct facilities or to purchase equipment, the labor costs required to staff a plant, some amount of equipment and supplies to operate the plant, gas pipeline reservation charges, etc. Given the unchanging nature of fixed costs, there is no interaction between the fixed costs of the various components of a scenario when Strategist dispatches the resources to meet load, so the fixed costs are simply tracked and summed within the model for the entire system for each year of analysis. In fact many of the fixed costs for a particular scenario are calculated outside the Strategist model but are input into the model so that they are accounted for along with the variable costs to allow a total cost value for each scenario to be calculated.

In contrast, variable costs are directly linked to how much a power plant is operated or how often a piece of equipment is utilized. Examples of variable costs are, fuel, consumables such as water or chemicals, the

reagent used in emission controls, certain on-going capital expenditures, energy purchases from the market, and emissions of NO_x, SO_2, CO_2, and Hg (to the extent that there are costs for emitting these substances). Given this relationship between plant or equipment operation and variable costs, there is an interaction between the variable costs of the various components of a scenario within Strategist when the model dispatches each generating unit to meet load. The magnitude of variable costs for each scenario are directly associated with how often the various generating units are called to operate in the Strategist model. As a result, all of the variable costs for a particular scenario must be calculated within a model such as Strategist.

Q. BESIDES THE COST AND PERFORMANCE ESTIMATES DISCUSSED ABOVE FOR THE INDIVIDUAL COMPONENTS OF EACH SCENARIO, WHAT OTHER ASSUMPTIONS WERE INCORPORATED INTO THE STRATEGIST MODELING OF SCENARIOS?

A. There are numerous other assumptions necessary to simulate operation of the Public Service electric supply system. Appendix 6 of Exhibit KTH-2 identifies the major modeling assumptions used in the evaluation of scenarios within the Strategist model.

Q. IN MODELING THE PSCO ELECTRIC SYSTEM OUT TO YEAR 2046, HOW WAS FUTURE LOAD GROWTH SERVED WITHIN THE MODEL?

A. Additional generation resources come on-line within the Strategist model as needed to maintain a planning reserve margin of approximately 16%

(i.e., planning reserves are generation capacity in excess of the forecast of annual peak load). Additional resources are modeled using what we call "generic" resource estimates, in that the cost estimates are not unique to a specific site or location but instead are generally descriptive of the technology and applicable at a number of different locations on the system. The entire mix of generic resources added to serve future year load growth is referred to as the generic expansion plan. Appendix 7 of Exhibit KTH-2 contains the cost and performance information for the generic resource technologies used in the development of this future generic expansion plan.

Q. HOW WAS THE FUTURE GENERATION EXPANSION PLAN THAT WOULD BE NEEDED TO SERVE FORECASTED LOAD GROWTH TO YEAR 2046 DEVELOPED?

A. The dynamic optimization capabilities of the Strategist model were used to develop a least-cost mix of generation additions for the existing PSCo system from these generic resource options similar to what was done in the Phase II evaluation of bids in Docket 07A-447E (i.e., the 2007 Colorado Resource Plan). The thermal generic resources identified on Table 6.1 of Exhibit KTH-2 were made available to Strategist and the model was allowed to pick and choose from this pool of resources in developing the future expansion plan. In addition, the generic non-PTC wind resources, 125 MW generic solar thermal with storage resources, and solar PV resources on Table 6.2 of Exhibit KTH-2 were manually

included into the future expansion plan in the amounts and years necessary to maintain compliance with Colorado's Renewable Energy Standard.

Appendix 7 of Exhibit KTH-2 shows the resources of the generic expansion plan developed from this process and used in the evaluation of the various scenarios. This generic expansion plan maintains a balanced mix of peaking resources, intermediate resources, and base load resources. Both the capital costs and operating costs (fuel, O&M, and emissions) of these generic resources are included in the annual costs as well as in the calculation of the present value of revenue requirements (PVRR) values reported for each scenario in Exhibit KTH-2.

Q. WAS THE SAME GENERIC EXPANSION PLAN USED IN THE MODELING OF THE DIFFERENT SCENARIOS?

A. Yes. Similar to the process that was approved in our last resource plan, Docket No. 07A-447E, all but about 1,000 MW of the generic expansion plan was locked down and thus was the same within the Strategist modeling for all scenarios. Two 505 MW generic 2x1 combined cycle (CC) units were removed from the generic expansion plan, one in year 2022 and another in year 2036, to allow the Strategist model the latitude to consider the characteristics of the scenario being examined (i.e., the components of each scenario in years 2011-2018) and select the most cost-effective generic thermal resource to add to the system. This approach of locking down most of the future generic expansion plan

ensures that differences in the PVRR costs among the scenarios are primarily the result of differences between the components that make up each scenario in the early years versus differences in the mix of speculative generic resources in the later years of the analysis. In other words, if the mix of resources that comprises the generic expansion plan were allowed to change significantly from one scenario to another, we would be uncertain as to whether the cost deltas among scenarios were due to the emission controls and coal unit shutdowns contained in the scenarios or, were the result of changes in the mix of speculative generics resources in future years. It is also important to note that the term "locked down" only refers to a particular resource being hardwired into the model to begin operation in a certain year, as opposed to being able to have a floating in-service date that is ultimately determined by the Strategist model. All generic resources that are "locked down" in the model were still fully capable of being economically dispatched with the rest of the fleet to meet customer load in a least-cost manner (with the exception of wind and solar PV which are not capable of being dispatched and are instead modeled with a fixed generation pattern, where the energy is used whenever it is generated).).

Q. TABLE 5.5 OF EXHIBIT KTH-2 SHOWS THAT THE MW AMOUNTS OF REPLACEMENT GENERATION CAPACITY IN SEVERAL SCENARIOS ARE EITHER MORE OR LESS THAN THE MW AMOUNTS OF COAL-FIRED GENERATION CAPACITY THAT WAS SHUTDOWN. HOW WAS

THIS DIFFERENCE IN THE MW SIZE OF DIFFERENT SCENARIOS ACCOUNTED FOR IN THE STRATEGIST MODELING?

A. Within the Strategist modeling of each scenario, firm generation capacity in excess of a 16.3% planning reserve margin was credited a dollar amount equal to the $/kW-year cost of the generic GE 7FA Combustion Turbine ("CT"), multiplied by the MW of excess capacity. Similarly, scenarios with less firm generation capacity than that required to maintain a planning reserve of 16.3% were assigned an additional dollar cost equal to the $/kW-year cost of the generic GE 7FA CT, multiplied by the MW of capacity deficiency. In both cases, this credit/cost was applied starting in 2016 since that is the first year Public Service is forecasting a capacity need and was applied only in years that excess capacity or capacity deficiency existed.

Q. BY GIVING THIS CAPACITY CREDIT TO SCENARIOS THAT INCLUDE ADDITIONAL GENERATION CAPACITY, SUCH AS SOLAR THERMAL OR PUMPED STORAGE HYDRO THAT CANNOT SERVE TO REPLACE THE RETIRED COAL-FIRED CAPACITY, IS THE COMPANY UNDERSTATING THE FULL MAGNITUDE OF ADDED COSTS THAT WOULD RESULT FROM THESE EXTRA GENERATING RESOURCES?

A. Yes. The Company believes that new generation capacity built to replace coal units that are shut down in the plan should be done as close as possible on a MW for MW basis, with consideration given to both maintaining reliability and to economies of scale. Including additional

generating facilities, such as solar thermal with storage or pumped storage, both of which would likely be located outside the Denver-Metro area, does not avoid the need to add replacement generation at Cherokee. The additional generating capacity that results from adding solar and pumped storage capacity for example is in excess of what Public Service needs in the near term to serve load, is outside the scope of the CACJA since it acts to fill a portion of the future resource need that would normally be addressed in the 2011 resource plan, and arguably should not be given any excess capacity credit. The Company, however, recognizes that other parties may not agree with this position. To provide these parties the information as to the additional costs and benefits of adding surplus generation to the plan, the Company elected to apply the excess capacity credit to all scenarios. Note that even with this excess capacity credit, replacement portfolios that included generation resources in addition to the gas-fired capacity needed at Cherokee showed higher costs.

IV. Basis for Carbon Proxy Cost

Q. HOW DOES THE COMPANY PROPOSE TO ASSESS THE POTENTIAL IMPACTS OF CARBON REGULATION?

A. Due to the potential for mandatory greenhouse gas policy addressed in the testimony of Gary Magno, the Commission has for several years required the Company to use a carbon proxy price to simulate a future cost for carbon dioxide emissions. The carbon proxy price reflects an

estimate of the expected future cost of emitting carbon dioxide under federal or state climate change legislation. The Company first used carbon proxy pricing in the 1999 Integrated Resource Plan, and later updated the carbon proxy pricing for use in our recent 2007 Electric Resource Plan (Docket No. 07A-447E). In the 2007 ERP, the Company proposed and the Commission approved the use of a carbon proxy price of $20/ton starting in 2010 and escalating at seven percent per year through the planning period. The Company proposes to use a similar approach in the CACJA docket.

Q. WHAT CARBON COST DID THE COMPANY UTILIZE IN THE MODELING OF SCENARIOS IN THIS EMISSION REDUCTION PLAN?

A. As discussed by Gary Magno, the Company utilized a cost of $20/ton starting in 2014 and escalating at 7%.

Q. DID THE COMPANY EVALUATE DIFFERENT CARBON PRICE SENSITIVITIES?

A. Yes. The Company believes the use of sensitivities helps understand the economic impact of a range of possible climate policies. In the June 11, 2010 CACJA workshop and in subsequent comments, several of the interveners in this docket asked that the Company consider a variety of different carbon proxy costs. Among other things, the interveners asked we consider higher and lower carbon proxy costs to model the effect of more stringent carbon regulation, different escalation rates, different start dates, and a scenario without any carbon proxy price at all.

On the low end, the Company has evaluated the various scenarios with a $0/ton cost for carbon, under the assumption that no carbon policy is enacted. On the high end, the Company evaluated scenarios using a carbon proxy cost of $40 per ton beginning in 2014 and escalating at 7% per year.

V. Strategist Scenario Analysis Results

Q. HOW DID THE % NO_x REDUCTIONS CALCULATED FROM THE STRATEGIST MODELING COMPARE WITH THOSE IN TABLE JFH-2 THAT WERE ESTIMATED WHILE SCREENING POTENTIAL SCENARIOS?

A. The Strategist modeling of scenarios resulted in NO_x emission reductions that were very much in line with those initially estimated during the scenario feasibility screening process. As was the case during the screening process, all of the scenarios examined in the plan meet the minimum 70% NO_x reduction threshold once all retirement and emission control actions have been completed.

Table JFH-3

		Benchmark		Scenarios						
		1	1.1	2	3	4	5	6	6.1	7
Table JFH-2 Screening Estimates	% NOx reduction 2018	72%	70%	81%	83%	83%	85%	67%	76%	84%
	% Nox reduction when all actions complete	72%	70%	81%	83%	83%	85%	89%	89%	89%
Strategist Model Estimates	% NOx reduction 2018	73%	73%	80%	81%	82%	83%	67%	75%	86%
	% Nox reduction when all actions complete	73%	73%	80%	81%	82%	83%	88%	89%	86%

Q. SCENARIO 6 APPEARS TO FALL SHORT OF THE 70% MINIMUM NOx REDUCTION REQUIREMENT BY 2018. WHY DO YOU STATE THAT ALL SCENARIOS MEET THE MINIMUM NO_x REQUIREMENTS OF CACJA?

A. Scenario 6 is very close to the 70% reduction requirement, modeled at 67% vs. 70%. In Scenario 6, Cherokee 4 is not retired until the end of 2018. If Public Service were to pursue Scenario 6, we could accept some restrictions on the operation of Cherokee 4 in that last year of operation in order to meet the 70% minimum NO_x reduction requirement. I note that after the retirement of Cherokee 4, we model an overall 88% reduction in NO_x emissions for Scenario 6.

Q. REGARDING TABLE 5.5 OF EXHBIT KTH-2, CAN YOU PROVIDE A HIGH LEVEL SUMMARY OF HOW THE COST OF THE VARIOUS SCENARIOS AND REPLACEMENT PORTFOLIOS COMPARE WITH ONE ANOTHER?

A. Yes. With the base assumptions for carbon ($20) and fuel, scenarios that include the retirement of 903 MW of coal at Cherokee and Valmont (Scenarios 6, 6.1, and 7) proved to be the lowest cost (2010-2046 PVRR). Scenarios with fewer coal unit retirements became progressively more expensive with the benchmark case (that does not retire any coal) being the most expensive. The lowest cost plan was 6.1E that retires Cherokee 1, 2, 3 and Valmont 5 by 2018, and both upgrades the low-NO_x burners and adds SNCR NOx controls on Cherokee 4 in 2012, operating the unit

through 2022 at which time it is retired. Replacement capacity for scenario 6.1E includes a 2x1 CC and a 1x1 Combined Cycle at Cherokee.

With regard to the group of scenarios that included additional generation located outside the Denver metro area (Pumped Storage, Solar Thermal, Fort St. Vrain CC, WRA), those that included the addition of the Fort St. Vrain CC were the lowest cost of this group. Scenarios became progressively more expensive with the addition of 1) solar thermal with storage, 2) the Western Resource Advocates ("WRA") portfolio of Southwest Generation ("SWG") units, wind, solar PV and solar thermal and, 3) Pumped Storage.

As expected, these same economic rankings occurred whether SCR was added to Pawnee and Hayden in all scenarios or not. This is due to the fact that from a cost perspective, the addition of SCR essentially adds only fixed costs to the various scenarios. If the same fixed cost is applied to all scenarios, there little change to their economic rankings relative to one another.

Table JFH-4 and JFH-5 summarize the economic rankings of scenarios with and without SCR on Pawnee and Hayden.

Table JFH-4

SCR on Pawnee and Hayden - $20 CO2 - Base Fuel								
Economic Ranking (2010-2046 PVRR)								
Portfolio Group	**Benchmark 1**	**2**	**3**	**4**	**5**	**6**	**6.1**	**7**
Cherokee	19	18	10	17	8	2	1	4
Fort St Vrain CC						3	6	5
Solar Thermal					13	9	7	11
Pumped Storage						15	14	16
WRA						12		

Table JFH-5

No SCR on Pawnee and Hayden - $20 CO2 - Base Fuel								
Economic Ranking (2010-2046 PVRR)								
Portfolio Group	**Benchmark 1.1**	**2**	**3**	**4**	**5**	**6**	**6.1**	**7**
Cherokee	19	18	9	17	10	2	1	4
Fort St Vrain CC						3	6	5
Solar Thermal					14	8	7	11
Pumped Storage						15	13	16
WRA						12		

Table 8.1 and 8.2 of Exhibit KTH-2 contain additional information about the results of these Strategist modeling analyses.

Q. DID THE RENEWABLE BOLT-ON OPTIONS OF SOLAR PV AND WIND IMPROVE THE ECONOMICS OF SCENARIOS?

A. The addition of 30 MW of solar PV to scenarios 5, 6, 6.1, and 7 reduced the 2010-2046 PVRR in the range of $21-$28 million. These reported solar PV cost savings, however, were not the result of lower cost solar PV energy displacing higher cost fossil energy but instead were almost entirely the result of the modeling convention that gave solar PV a capacity cost credit based on a GE7FA CT. I note that, a San Luis Valley location was assumed for the solar PV "bolt-on" analysis. Given the San Luis Valley is the premier solar resource in the state, this assumption gave

solar PV a low $/MWh price and as a result, the best opportunity to show savings. If an inferior solar location were used, the net savings noted above would have been reduced even further. In contrast, the addition of 100 MW of PTC priced wind to these same scenarios added cost in the range of $12-$22 million.

Q. DID THE FIVE INDEPENDENT POWER PRODUCER ("IPP") GAS UNITS DISCUSSED EARLIER IN YOUR TESTIMONY SHOW ECONOMIC VALUE TO THE PLAN?

A. No. Various combinations of the three SWG units, Arapahoe, Valmont, and Fountain Valley were examined in a variety of ways: 1) as components to WRA scenario 6I, 2) as replacements to Arapahoe 4 operating on gas and, 3) as replacements to the Fort St. Vrain Combined Cycle facility. WRA scenario 6I was $244 million higher cost (2010-2046 PVRR) than the Company's preferred plan. Replacing Arapahoe 4 on gas with SWG Arapahoe and SWG Valmont showed $53 million higher cost (2010-2046 PVRR) than the Arapahoe 4 option. Similarly, replacing the Fort St. Vrain Combined Cycle with SWG Fountain Valley and SWG Valmont showed $111 million higher cost (2010-2046 PVRR) than the Fort St. Vrain option[4].

At the request of WRA, the other two IPP units located in Greeley Colorado were included in a scenario that examined the retirement of Pawnee and the addition of renewables. This WRA scenario resulted in

[4] Details of these IPP analyses are contained in Highly Confidential Appendix 5 to Exhibit KTH-2.

significantly higher costs compared to scenarios 6E, 6.1E, and 7E (over $600 million) but these higher costs were driven by the retirement of Pawnee not the economics of the two IPP offers. Nevertheless, neither of these IPP facilities will act to serve any portion of the generation needed to replace retired Cherokee coal units and therefore would merely result in excess capacity and costs. In addition, I believe it would be inappropriate to select these facilities as part of the emission reduction plan which in essence is allowing them an early chance to meet a portion of the 2011 resource planning need without participating in an All-Source competitive acquisition process.

Q. CAN YOU BREIFLY SUMMARIZE HOW DIFFERENT CARBON COSTS IMPACTED THE MODELING RESULTS?

A. Yes. Not surprisingly, under $0 carbon, certain scenarios with fewer coal unit retirements (3B with 365 MW retired and 5B with 551 MW retired) that were more expensive under $20 carbon became lower cost with $0 carbon (2010-2046 PVRR). Table JFH-6 shows that scenarios 3B and 5B both improve several spots in the rankings. Scenario 6.1E, which was the lowest cost under $20 carbon, dropped to third lowest followed by scenario 6E (both 6.1E and 6E retire ~ 900 MW of coal). The economics of the benchmark scenario, which was the highest cost plan under $20 carbon, improved but remained $200 to $300 million higher cost than the lowest cost scenarios (3B, 5B, and 6.1E). Scenario 7, which retires 903

MW of coal by 2013, ranked significantly worse under $0/ton carbon versus $20/ton.

Under $0 carbon the addition of the Fort St. Vrain Combined Cycle (6.1H) was again the lowest cost from the group of scenarios that include additional generation located outside the Denver-Metro area (Pumped Storage, Solar Thermal, Fort St. Vrain CC, WRA) with scenarios again becoming progressively more expensive with the addition of 1) solar thermal with storage, 2) Pumped Storage, and 3) the WRA portfolio of SWG units with wind, solar PV and solar thermal.

Table JFH-6

SCR on Pawnee and Hayden - **$0 CO2** - Base Fuel								
Economic Ranking (2010-2046 PVRR)								
Portfolio Group	**Benchmark 1**	**2**	**3**	**4**	**5**	**6**	**6.1**	**7**
Cherokee	8	12	1	11	2	4	3	9
Fort St Vrain CC						6	5	14
Solar Thermal					7	15	10	17
Pumped Storage						16	13	18
WRA						19		

Table 8.10 of Exhibit KTH-2 contains additional information about the results of these Strategist modeling analyses.

Doubling cost of carbon from $20 to $40 caused the economics of scenarios with fewer coal retirements to deteriorate while those which added carbon free generation resources such as solar and wind improved (see Table JFH-7). The WRA scenario (6I) with 300 MW of wind, 60 MW of solar PV, and 125 MW of solar thermal with storage moves from being one of the most expensive scenarios under $20 carbon, to the lowest cost

scenario. Similarly, the addition of solar thermal with storage to scenarios that include the retirement of 903 MW of coal generation (6G, 6.1G, 7G), now acts to improve these scenarios whereas under $20 carbon, the solar thermal addition was a significant cost adder in the range of $160 million PVRR.

Table JFH-7

SCR on Pawnee and Hayden - **$40 CO2** - Base Fuel								
Economic Ranking (2010-2046 PVRR)								
Portfolio Group	**Benchmark 1**	**2**	**3**	**4**	**5**	**6**	**6.1**	**7**
Cherokee	19	18	16	17	15	8	10	7
Fort St Vrain CC						6	9	4
Solar Thermal					14	3	5	2
Pumped Storage						12	13	11
WRA						1		

These results highlight the value of carbon free resources in a high carbon cost future. To the extent there is more clarity regarding future carbon legislation by the time Public Service files its 2011 Resource Plan, the Company will be able to pursue these very types of carbon free resources that are included in the WRA scenario in that upcoming resource plan. Table 8.11 of Exhibit KTH-2 contains additional information about the results of these Strategist modeling analyses.

Q. YOU INDICATED THAT THE COMPANY PERFORMED A SIGNIFICANT NUMBER OF "BOLT-ON" AND SENSITIVITY ANALYSES. WHERE IN EXHIBIT KTH-2 CAN THE RESULTS OF THESE VARIOUS ANALYSES BE FOUND?

A. We provide a "roadmap" of the scenarios analyzed in Appendix 9 to Exhibit KTH-2. Public Services decision to solicit comments from parties on the various scenarios that should be examined in the Plan, and our efforts to accommodate as many of these suggestions as possible, greatly expanded the amount of analyses that were performed and complicates the presentation of results in an easy to follow manner. To aid parties in the review and comparison of results, we provide results in Section 8 of Exhibit KTH-2 in the following order.

Base Analyses
Table 8.1 - Summary Table of Results (SCR on Pawnee and Hayden)
Table 8.2 - Summary Table of Results (No SCR on Pawnee and Hayden)

Sensitivities to Base Analyses ***with*** **SCR on Pawnee and Hayden**
Table 8.3 - High Gas/High Coal Sensitivity
Table 8.4 - Low Gas/Low Coal Sensitivity
Table 8.5 - Flat Gas/Low Coal Sensitivity
Table 8.6 - No PVM Adder Sensitivity
Table 8.7 - WoodMac Coal Forecast 2 Sensitivity
Table 8.8 - 2009 SO2 and NOx Forecast Price Sensitivity
Table 8.9 - Carper SO2 and NOx Forecast Price Sensitivity
Table 8.10 - \$0/Ton CO_2 Price Sensitivity
Table 8.11 - \$40/Ton CO_2 Price Sensitivity
Table 8.12 - +30% Construction Costs Sensitivity
Table 8.13 - 130% DSM Sensitivity

Sensitivities to Base Analyses ***without*** **SCR on Pawnee and Hayden**
Table 8.14 - 2009 SO2 and NOx Forecast Price Sensitivity
Table 8.15 - Carper SO2 and NOx Forecast Price Sensitivity
Table 8.16 - \$0/Ton CO_2 Price Sensitivity
Table 8.17 - \$40/Ton CO_2 Price Sensitivity

Bolt-On Summary Tables
Table 8.18 - Cherokee Group Bolt-On Table
Table 8.19 - Fort Saint Vrain Group Bolt-On Table
Table 8.20 - Solar Thermal Group Bolt-On Table
Table 8.21 - WRA Group Bolt-On Table
Table 8.22 - Pumped Storage Group Bolt-On Table
Table 8.23 - Renewable Bolt-On Sensitivities

IPP Sensitivity Analyses (SCR on Pawnee and Hayden)
Table 8.24 - IPP Sensitivities

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Attachment A

Statement of Qualifications
James F. Hill

I graduated from Colorado State University in 1983 with a Bachelor of Science degree in Natural Resource Management and in 1995 from the University of Colorado with a Bachelor of Science degree in Mechanical Engineering.

I have been employed by Public Service Company of Colorado, New Century Services, Inc., and now Xcel Energies Services Inc. for 26 years. I began my employment in 1984 at Public Service Company of Colorado's Fort St. Vrain Nuclear Generating Station in the Technical Services and Licensing Department. In August 1992, I joined Public Service Company of Colorado's System Planning Department where I performed resource planning functions, as a Planning Engineer, a Senior Resource Planning Analyst, Manager of Resource Planning and Bidding and now Director of Resource Planning and Bidding with a focus on Public Service Company of Colorado.

As the Director of the Resource Planning and Bidding Group, I have responsibility for overseeing the Company competitive resource acquisition processes as well as the various technical analyses on the resource options that are available to Xcel Energy's operating companies for meeting customer demand.

I have testified before the Colorado Public Utilities Commission regarding electric resource planning issues in numerous dockets.

Case: UE 374
Exhibit Number: Sierra Club/200
Witness: David B. Posner

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of

PACIFICORP d/b/a PACIFIC POWER,

Request for a General Rate Revision

Opening Testimony of David B. Posner

On Behalf of Sierra Club

June 4, 2020

TABLE OF CONTENTS

I. Introduction 1

II. Examination of the relationship between long-term bond yields and regulated utility equity costs 4

III. Will the Company's credit rating be at risk if the requested increases to ROE and equity ratio are not granted? 8

IV. Weighted Return on Equity 10

TABLE OF FIGURES

Figure 1: 30-Year Treasury Yields from January 2019 through May 2020. 6

Figure 2: Company Witness Bulkley's Graphic Confirms the relative stability of Treasury bond yields from 2012 through 2019. 7

Figure 3: 30-Year Treasury Yields from Before the Great Recession until today. 8

Figure 4 : WROEs as plotted by company witness Bulkley as well as for company's proposal. 12

Figure 5: WROEs off Proxy Group Companies approved in 2018 and 2019. 13

LIST OF EXHIBITS

Sierra Club/201	Curriculum Vitae of David Posner
Sierra Club/202	Morgan Stanley, *The second wave of clean energy*, (December 10, 2019)
Sierra Club/203	American Electric Power, *2019 AEP Fact Book* (2019)
Sierra Club/204	U.S. Securities and Exchange Commission, Alliant Energy Form 10-K for the fiscal year ended December 31, 2019

I. Introduction.

Q. Please state your name and business address.

A. My name is David B. Posner. I am an independent consultant. My business address is 1801 Wedemeyer Street Unit 322, San Francisco, CA 94129.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Sierra Club.

Q. Please summarize your educational background and recent work experience.

A. I was graduated from Cornell University in 1989 with a Bachelor of Arts degree in history. In 1997, I received a Doctor of Philosophy degree in history from Yale University. In 2003, I received a Master of Business Administration degree in finance from the Wharton School of the University of Pennsylvania.

Since 2006 I have worked on energy finance matters for the U.S. Department of Energy as well as for various non-profit organizations and for-profit companies. I have testified before the New Mexico Public Regulation Commission.

A copy of my current resume is included as Exhibit Sierra Club/201.

Q. Have you previously testified before this Commission?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. I call into question PacifiCorp's (hereafter, the "company") arguments in support of its requests for an increase in its authorized return on equity ("ROE") to 10.2%, up from the current level of 9.3%, and an expansion of the share of common equity in the authorized capital structure to 53.52%, up from the 52.1% approved in the 2013 rate case.

Q. Please summarize your findings.

A. My main findings are as follows:

1. The company predicts a rise in long-term interest rates will encourage investors to reallocate capital away from shares in regulated utilities and into bonds, which would increase the company's cost of raising equity.[1] As we now know, 30-year Treasury rates, the most relevant forward looking metric, have plummeted since the onset of the Covid-19 pandemic.

   The ongoing pandemic and the significant efforts undertaken by the Federal Reserve to ease access to credit have pushed down yields on Treasury Bonds and most U.S. bonds, as the latter are priced off the former. However unexpected this situation, it has transpired, and its effects may well linger long after the worst of the health crisis passes.

   With interest rates at low levels, equities with stable yields are a desirable haven for investors seeking yield. This relationship was in evidence following the Great Recession that began in 2008 but endured long after recovery from that slump began. Indeed, precisely this lasting impact is noted in the direct testimony of company witness Ann E. Bulkley.[2]

2. The company contends that its future capital expenditure ("CAPEX") plans, which are slightly above its peer group average (calculated as a percentage of net utility plant), raise risk in investors' eyes and thus argue in favor of a higher ROE.[3] But

[1] PAC/400, at Bulkley/16:3-17:11.
[2] *Id.* at Bulkley/14, Figure 2.
[3] *Id.* at Bulkley/66:8-10.

there is conflicting analysis, including a recent research report by Morgan Stanley that observes that companies at the forefront of the clean energy transition are being valued by markets above their peers (thus decreasing the cost they incur in raising equity).[4]

3. All other conditions held equal, an increase in approved ROE should justify a lower equity ratio, since equity investors expecting to be compensated more generously for each dollar invested should accept being subordinated to more debt. Analogously, creditors' repayment concerns should be eased by the presence of greater returns for each dollar of equity with only a residual claim on those returns. The company argues that the credit negative impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA" or "2017 tax cut") should be offset by higher returns to equity and thicker equity layers, and, indeed, approved weighted returns on equity ("WROEs"), which reflect ROEs multiplied by equity ratios, have trended upward since the tax reform. But the WROE requested by the company in this proceeding would, if approved, be among the highest granted to peer utilities in recent years, well above levels granted to utilities with similar CAPEX plans and credit ratings.

Q. Please summarize your recommendation.

A. I recommend the retention of the currently approved equity ratio of 52.1% and an increase of the approved ROE to 9.8%. This will place the company's WROE at 5.1%, in line with WROEs approved for similar entities—i.e., with similar credit ratings and CAPEX needs—since the 2017 tax cut came into effect. The current equity ratio is

[4] Morgan Stanley, *The second wave of clean energy* at 5 (December 10, 2019), *available at* https://www.ivo-welch.info/teaching/co2/Background%20materials/Morgan%20Stanley%20Second%20Wave%20of%20Renewables.pdf [hereinafter "Morgan Stanley Report"] (attached as Exhibit Sierra Club/202).

slightly below the proxy group average of 52.43% cited by company witness Bulkley,[5] but this is justified by the financial strength of the company's parent company, Berkshire Hathaway Energy Company.[6] As described in the credit opinion of PacifiCorp updated by Moody's Investor Service in June 2019, "From a credit perspective, the company's ability to retain its earnings as an entity that is privately held, particularly by a deep-pocketed sponsor like BRK, is an advantage over most other investor owned utilities that are typically held to a regular dividend to their shareholders."[7] This credit advantage facilitates the company's use of more debt.

Q. What materials did you review and what analyses did you prepare as part of the preparation of your testimony?

A. I have reviewed the prepared direct testimony of witnesses Ann E. Bulkley and Nikki L. Kobliha, as well as the documents they included as exhibits. I have prepared this testimony using published sources as well as documents provided by the company as work papers and in response to discovery. In one case, I have adapted a graphic prepared by witness Bulkley, extending it to incorporate information not included in her original.

II. <u>Examination of the relationship between long-term bond yields and regulated utility equity costs.</u>

Q. How do low bond yields affect regulated utility equity costs?

A. When yields on long-term bonds are low, some bond investors may "chase yield" by shifting investments out of fixed income into equity. While even the safest equities experience more volatility than high investment grade bonds, regulated utilities offer

[5] PAC/400 at Bulkley/82:6-8.
[6] In support of this contention, see PAC/300 at Kobliha/13:8-14:2.
[7] Moody's Investor Service, *PacifiCorp: Update to credit analysis* at 6 (June 27, 2019) [hereinafter "Moody's PacifiCorp Update"].

relative safety among stocks. If yield chasers move to purchase the shares of regulated utilities, this will push up the price of these stocks relative to risk equities. In turn, dividend yields (for an unchanged dividend as a percentage of increased share price) will decline. As long as they remain above bond yields, they will remain attractive to this newly interested investor class, while traditional investors will have benefited from share price appreciation. In so far, I am in general agreement with company witness Bulkley.[8]

Q. Do you disagree with company witness Bulkley's forecast for the future yield environment?

A. Yes. In February 2020, company witness Bulkley wrote that "yields on long-term bonds are expected to increase" and that "recent historical market conditions are not reflective of the market conditions that will be present when the rates for PacifiCorp will be in effect."[9] Since the onset of the Covid-19 pandemic, yields on long-term Treasury Bonds have plunged (see Figure 1), underscoring the difficulty of predicting interest rate developments.

[8] PAC/400, Bulkley/13:6-18.
[9] *Id.* at Bulkley/33:17-20.

Figure 1: 30-Year Treasury Yields from January 2019 through May 2020.[10]

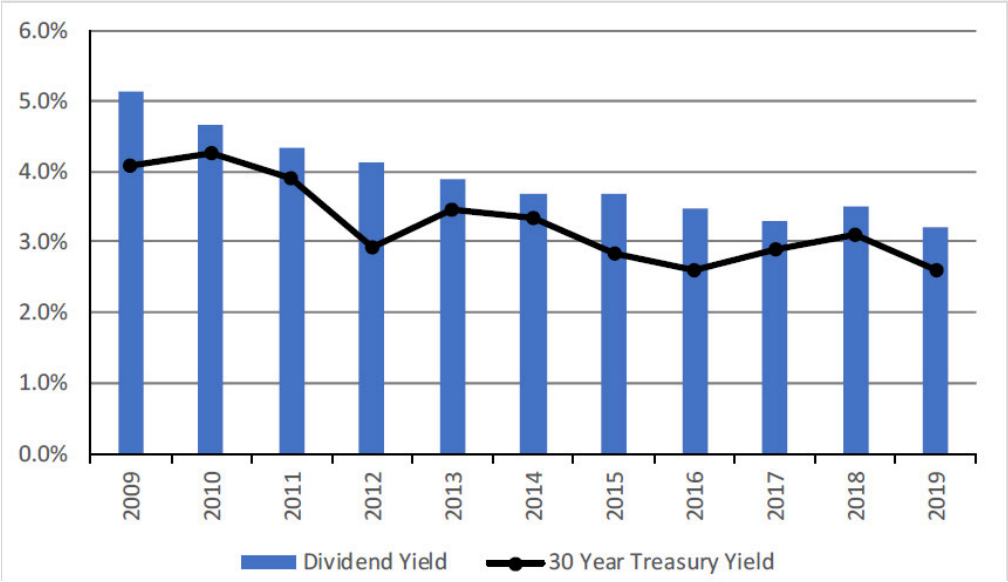


Q. How have yields behaved since the last time the company ROE was approved in 2013?

A. Company witness Bulkley's own testimony reveals that the yield on 30-year Treasuries moved within a narrow band from 2013 through 2019, all the while failing to again match the level achieved in 2013 (see Figure 2).

[10] Board of Governors of the Federal Reserve System (US), *30-Year Treasury Constant Maturity Rate [DGS30]*, FRED, Federal Reserve Bank of St. Louis, *available at* https://fred.stlouisfed.org/series/DGS30, (last accessed May 25, 2020).

Figure 2: Company Witness Bulkley's Graphic Confirms the relative stability of Treasury bond yields from 2012 through 2019.[11]



Q. Is it reasonable to expect that yields will surge after the current economic turmoil ends and the Federal Reserve reduces interventions to ease access to credit?

A. No. Notably, yields have yet to return to levels that prevailed before the Great Recession of 2008-2009 (see Figure 3).

[11] PAC/400 at Bulkley/14, Figure 2.

Figure 3: 30-Year Treasury Yields from Before the Great Recession until today.[12]



III. Will the Company's credit rating be at risk if the requested increases to ROE and equity ratio are not granted?

Q. Discussing the impact of the 2017 tax cut, company witness Kobliha argues that "the negative impact to the Company's key credit metric (Moody's CFO pre-W/C/Debt) has not yet been fully realized. Absent regulatory support for a stronger capital structure . . . the Company's cash from operations will likely fall below levels where it can maintain the minimum 20 percent expectation for this credit metric, which could increase the likelihood of a downgrade."[13] **Do you agree?**

A. No. Moreover, in its June 2019 PacifiCorp credit opinion, Moody's did not share that pessimistic prediction, instead "anticipat[ing] that PacifiCorp's credit metrics will be

[12] Board of Governors of the Federal Reserve System (US), *30-Year Treasury Constant Maturity Rate [DGS30]*, FRED, Federal Reserve Bank of St. Louis, *available at* https://fred.stlouisfed.org/series/DGS30, (last accessed May 25, 2020).
[13] PAC/300 at Kobliha/14:20-25.

sustained near current levels, for example, CFO pre-W/C/Debt in the low 20% range."[14] Notably, Moody's did not presuppose an impending increase in the company's allowed ROE or equity ratio. On the contrary, Moody's opinion was that "[g]oing forward...the lack of revenue growth and rate case activity will contribute to ROEs remaining near current levels, down somewhat from the over 10% ratios achieved in 2016 and 2017."[15] In addition, the Moody's opinion considered that "PacifiCorp has also received regulatory pre-approvals for the majority of its planned $1 billion of repowering projects."[16]

Q. Do you agree with company witness Bulkley that "PacifiCorp's elevated capital expenditure requirements result in a risk profile that is greater than that of the proxy group and supports an ROE toward the higher end of the reasonable range of ROEs"?[17]

A. No. The ratio of the company's projected capital expenditures for the period from 2020-2024 divided by its total net utility plant as of December 31, 2018 is exceeded by many of the companies in the peer group selected by the company, resulting in, to quote company witness Bulkley, just "slightly greater risk relative to the companies in the proxy group."[18] Eighteen subsidiaries of the companies in the proxy group have had ROEs approved since the beginning of 2018, and none of these was above 10%.[19]

[14] Moody's PacifiCorp Update at 2.
[15] *Id.* at 5.
[16] *Id*. at 4.
[17] PAC/400, Bulkley/67:9-11.
[18] *Id.* at Bulkley/66:3-10.
[19] *Id,* at Bulkley/73:13, Figure 15, Bulkley/84:1-2, Figure 17; Data from workpaper supporting the Direct Testimony of Ann E. Bulkley on behalf of PacifiCorp "Figure 15 & 17, ROE Range Analysis" at tab, Charts [hereinafter "Bulkley Workpapers"].

It is also true that investors may reward a company's decision to join in the transition to renewables by purchasing shares and pushing up share price, thus reducing the company's cost of raising equity. This is the finding of a recent Morgan Stanley's research report, which argued that **"**[d]riven by the surprisingly low cost of renewables . . . carbon-heavy utilities that have not historically led the pack in clean energy deployment will accelerate their earnings growth by pursuing a 'virtuous cycle': shutting down expensive coal plants and investing in cheap renewables. As a result, these 'Second Wave Utilities', which all trade at valuation discounts relative to peers, could achieve a valuation re-rating."[20] Now the company appears to be joining this "second wave," with the company's witnesses highlighting its future investments in renewables as well as its current disproportionate reliance on coal relative to peers.[21] If the Morgan Stanley analysis is borne out, the company may experience a boost in share price, lowering their cost of equity in the future investments.

IV. <u>Weighted Return on Equity.</u>

Q. What is the Weighted Return on Equity (WROE)?

A. WROE is the product of approved ROE times the approved equity share of the capital structure (the equity ratio). It is a key element in company witness Bulkley's testimony, for, as she writes, "[i]t is the combination of the equity ratio and the authorized ROE that defines the return to investors."[22]

[20] Morgan Stanley Report at 3.
[21] *See* PAC/300 at Kolbiha/3:13-4:7; PAC/400 at Bulkley/79:1-80:3.
[22] PAC/400, Bulkley/84:9-10.

Q. Does a higher WROE mean that investors are getting a higher return in percentage terms?

A. No. Either a higher ROE or a higher equity ratio can move a WROE upward. If two companies have the same approved ROE but different approved equity ratios, investors in the company with the higher equity ratio can expect larger absolute returns for a larger amount of equity invested. That said, a larger equity cushion serves to lessen the risk of default, thus increasing the attractiveness of an approved ROE, other factors held constant.

Q. Did company witness Bulkley's testimony accurately characterize the twenty-three companies in the proxy group chosen to evaluate PacifiCorp against its peers?

A. Yes. According to Ms. Bulkley, they all possess a set of operating and risk characteristics that are substantially comparable to PacifiCorp, and thus provide a reasonable basis to derive an estimate of the appropriate ROE for PacifiCorp."[23] While this group is far broader than the peer groups selected by Moody's and Standard & Poor's in their credit opinions, it does offer a reasonable basis for comparison.[24]

Q. How would the company's requested WROE compare against recently approved WROEs, including for members of the proxy group?

A. If approved, the company's WROE would be higher than all but two of the nearly 30 approved since beginning of 2018, when the 2017 tax cut came into effect. Those two are Madison Gas & Electric (2018, 5.49%) and Wisconsin Electric Power (2019, 5.45%).[25] Neither of these utilities is a member of the company's proxy group. To illustrate this, I

[23] PAC/400, Bulkley/34:2-16.
[24] Moody's PacifiCorp Update at 9; Standard & Poor, *PacifiCorp,* at 6 (March 15, 2019).
[25] Bulkley Workpapers at tab, US Cases.

have adapted data provided by company witness Bulkley. Ms. Bulkley's already calculates WROE for the proxy group; I have added only one new data point, which depicts the WROE of the company's proposal (5.43%). I have added a label and legend entry for this point as well as a label for the company's currently approved WROE. I have also extended the horizontal (x) axis (see Figure 4).

Figure 4 : WROEs as plotted by company witness Bulkley as well as for company's proposal.[26]

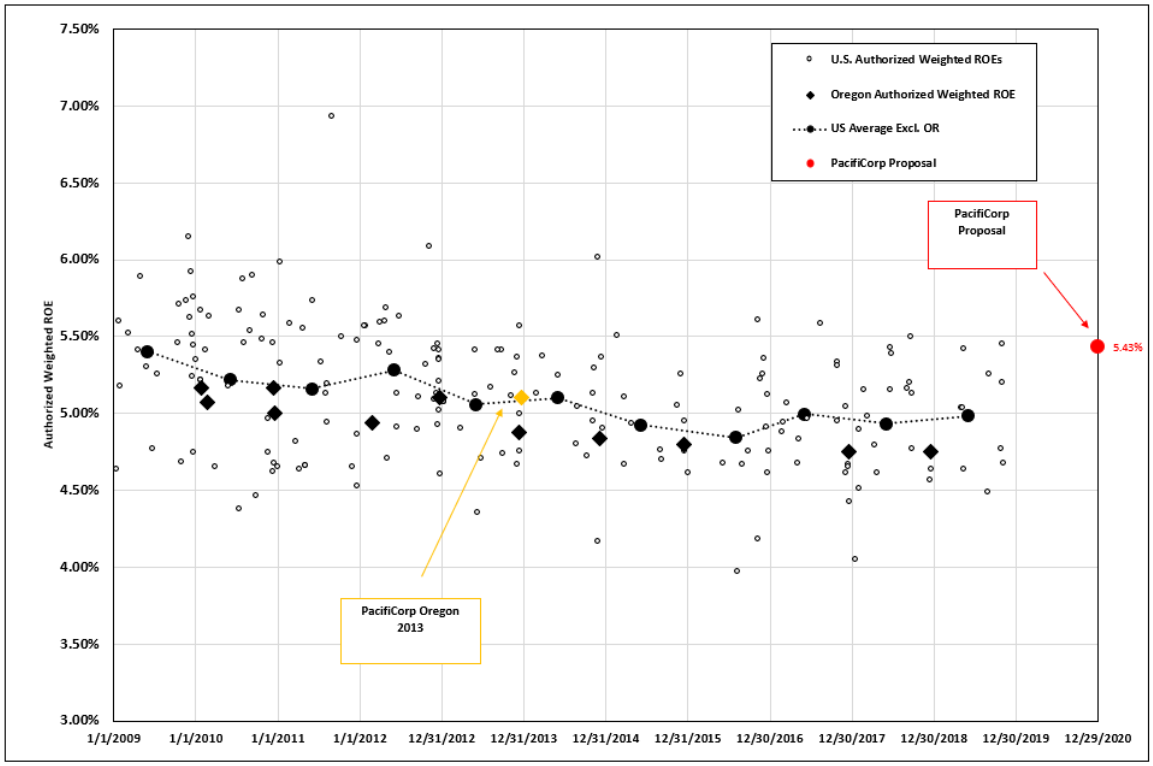


Figure 5 below is an excerpt of Ms. Bulkley's data set containing all the WROEs approved since the beginning of 2018 for subsidiaries of companies in company witness Bulkley's proxy group. None is higher than the company's current proposal. The yellow

[26] Adapted from *Id.* at tab, Charts.

shaded companies rank higher than PacifiCorp on witness Bulkley's comparison of CAPEX needs[27].

Figure 5: WROEs off Proxy Group Companies approved in 2018 and 2019.[28]

State	Company	Parent Company	Docket		Year	WROE
Iowa	Interstate Power & Light Co.	LNT	D-RPU-2017-0001	Electric	2018	4.89%
Kansas	Evergy Kansas Central Inc.	EVRG	D-18-WSEE-328-RTS	Electric	2018	4.77%
Kansas	Evergy Metro Inc	EVRG	D-18-KCPE-480-RTS	Electric	2018	4.57%
Kentucky	Duke Energy Kentucky Inc.	DUK	C-2017-00321	Electric	2018	4.79%
Kentucky	Kentucky Power Co.	AEP	C-2017-00179	Electric	2018	4.04%
Louisiana	Entergy New Orleans LLC	ETR	D-UD-18-07 (elec.)	Electric	2019	4.68%
Minnesota	ALLETE (Minnesota Power)	ALE	D-E-015/GR-16-664	Electric	2018	4.98%
Montana	NorthWestern Corp.	NWE	D2018.2.12	Electric	2019	4.77%
North Carolina	Duke Energy Carolinas LLC	DUK	D-E-7, Sub 1146	Electric	2018	5.15%
North Carolina	Duke Energy Progress LLC	DUK	D-E-2, Sub 1142	Electric	2018	5.15%
New Mexico	Southwestern Public Service Co	XEL	C-17-00255-UT	Electric	2018	5.16%
Oklahoma	Public Service Co. of OK	AEP	Ca-PUD201700151	Electric	2018	4.51%
South Carolina	Duke Energy Carolinas LLC	DUK	D-2018-319-E	Electric	2019	5.04%
South Carolina	Duke Energy Progress LLC	DUK	D-2018-318-E	Electric	2019	5.04%
Washington	Avista Corp.	AVA	D-UE-170485	Electric	2018	4.61%
Wisconsin	Northern States Power Co - WI	XEL	D- 4220-UR-124 (Elec)	Electric	2019	5.25%
Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-121 (Elec)	Electric	2018	5.20%
West Virginia	Appalachian Power Co.	AEP	C-18-0646-E-42T	Electric	2019	4.89%

Notably, several peers with forecasted CAPEX needs greater than the company's were allowed lower WROEs than the company has requested, despite having relatively weaker credit ratings. For instance, senior unsecured debt of Kentucky Power is rated only Baa3 by Moody's as of September 30, 2019.[29] Interstate Power & Light's rating for senior unsecured debt (and as a corporate issuer) is Baa1.[30] In my opinion, the judgments of the regulators in Kentucky and Iowa were reasonable.

Q. What WROE would you recommend?

A. I would recommend a WROE of 5.1%, in line with WROEs approved since the beginning of 2018, as evidenced by Ms. Bulkley's testimony. This is greater than the company's current WROE of 4.66%; this increase would offer reasonable protection to the company

[27] *See* PAC/400 at Bulkley/66, Figure 14.
[28] Data from Company Witness Bulkley Figure 15 & 17_ROE Range Analysis.
[29] *See* American Electric Power, *2019 AEP Fact Book* at 37 (2019), *available at* https://www.aep.com/Assets/docs/investors/eventspresentationsandwebcasts/2019Factbook_All%20Sections_FINAL.pdf (attached as Exhibit Sierra Club/203).
[30] U.S. Securities and Exchange Commission, Alliant Energy Form 10-K for the fiscal year ended December 31, 2019 at 35 (attached as Exhibit Sierra Club/204).

adverse credit impact of the 2017 tax cut and forecasted CAPEX growth. A WROE of 5.1% could be achieved by maintaining the currently approved equity ratio and raising the approved ROE to 9.8%. An approved ROE of 9.8 would be within the range Ms. Bulkley deemed reasonable.[31]

Q. Does this complete your testimony?

A. Yes.

[31] PAC/400 at Bulkley/4:3-4.

Docket No. UE 374
Exhibit Sierra Club/201
Witness: David B. Posner

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 201

Exhibits Accompanying the Opening Testimony of David B. Posner

David B. Posner CV

David B. Posner, PhD, MBA

1801 Wedemeyer Street Unit 322, San Francisco, CA 94129
Tel.: 215-820-7074 ● Email: dbposner@gmail.com

Finance professional specializing in the deployment of clean energy technologies
Former senior policy advisor at the U.S. Department of Energy
Wharton MBA | Yale PhD | Fulbright Scholar

EMPLOYMENT

Energy Finance Consulting — San Francisco, CA
Consultant — July 2018 – present

- Advising on financial mechanisms to facilitate clean energy deployments, including securitization, market-indexing of solar assets for regulated utilities, and tax equity partnership structures.
- Clients: Rocky Mountain Institute; Sierra Club; IHS Markit.

Climate Policy Initiative — San Francisco, CA
Consultant, Energy Finance Program — April 2016 – June 2018

- **U.S. Utility Capital Recycling Program:** developed capital recycling strategies that employ ratepayer-backed securitizations to retire uneconomic fossil generation and encourage utility reinvestment in wind and solar as well as demand-side assets, all at a net savings for ratepayers; co-author of *Harnessing Financial Tools to Transform the Electric Sector*.
- **Clean Energy Investment Trust (CEIT):** contributed to the design of a structured financing approach for renewable energy projects that increases the share of investment-grade debt (or debt equivalents) in the capital stack through the use of a portfolio of risk mitigation tools; co-author of *Structuring the Clean Energy Investment Trust*.
- **Flexibility:** evaluated policy, technology, and market options that can satisfy the need for flexibility in high-penetration renewable energy power systems; co-author of *Flexibility: the path to low-carbon, low-cost electricity grids*.
- **Energy Markets:** co-author of comments by CPI and Energy Innovation on the Department of Energy's *Grid Resilience Notice of Proposed Rulemaking*.

Alliance to Save Energy — Washington, DC
Program Manager, Financial & Economic Policy — February 2015 – April 2016

- Project leader for *CarbonCount*™, a quantitative CO_2 impact scoring system for "green" bonds; winner of a *Finance for Resilience* (*FiRe*) prize at the *2015 BNEF Future of Energy Summit*.
- Collaborated with utilities, green banks, underwriters, and investors to validate sustainability claims.

Energy Finance Consulting — Arlington, VA
Consultant — July 2013 – January 2015

- Advised on the role of efficiency in the Clean Power Plan, time-variant electricity pricing, and "green" bonds.
- Clients included Rocky Mountain Institute, the University of Pennsylvania, and the Alliance to Save Energy.

U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy — Washington, DC
Lead Energy Technology Program Specialist, GS-14 — January 2010 – June 2013

- Team Leader for Business Operations of the State Energy Program; oversaw data collection and impact assessment for $3.1 billion in Recovery Act (ARRA) investments in energy efficiency and renewable energy projects across the U.S.
- Recipient of the Department's *Special Service Award* in recognition of superior performance of duties.

Senior Analyst, contractor employed through Sentech Inc. — February 2009 – January 2010

- Member of the start-up team that launched the Energy Efficiency and Conservation Block Grant Program (EECBG), which directed $3.2 billion in funding to over 2,300 awardees, including states, counties, and municipalities.

David B. Posner, PhD, MBA

Securing America's Future Energy (SAFE) Washington, DC
Consultant January 2008 – January 2009

- Principal researcher and author of *A National Strategy for Energy Security* (2008), a report issued by the Energy Security Leadership Council, an advocacy project co-chaired by Frederick W. Smith, Chairman, President, and CEO, FedEx Corp., and General P.X. Kelley, USMC (Ret.), 28th Commandant of the U.S. Marine Corps.

Vice President, Policy & Business Outreach June 2006 – January 2008

- Principal researcher and author of *Recommendations to the Nation on Reducing U.S. Oil Dependence* (2006).
- Designed and vetted scenarios for *Oil ShockWave*, a multimedia crisis simulation in which participants acting as cabinet officials confronted threats to the global oil supply and proposed policy responses.

Policy Studies Inc. Denver, CO
Senior Strategy Analyst October 2004 – April 2006

- Prepared financial proposals and operating budgets for competitively awarded government outsourcing opportunities in the healthcare and welfare sectors.

JPMorgan Chase/Chase Manhattan Automotive Finance Corporation Garden City, NY
Assistant Vice President October 2003 – September 2004

- Planned and executed market segmentation studies to improve the profitability and risk profile of an indirect loan business with 13,000 dealers and over $27 billion in annual originations.

General Motors Corporation New Haven, CT
Consultant, GM/Adam Opel World War II Project December 1998 – August 2001

- Investigated GM's managerial control of its German subsidiary, Opel, during the Nazi period; advised GM General Counsel and other executives as they developed a reparations program for wartime slave workers.

EDUCATION

The Wharton School, University of Pennsylvania Philadelphia, PA
Master of Business Administration, Finance, with honors September 2001 – May 2003

- Director's List; course concentration in fixed income, speculative markets, and financial engineering.

Yale University New Haven, CT
Postdoctoral Research Assistant, International Security Studies Program September 2000 – May 2001
Doctor of Philosophy, History September 1990 – May 1997

Fulbright-Hays Scholar Saarbrücken, Germany
Germany-U.S. Exchange Program August 1989 – July 1990

Cornell University Ithaca, NY
Bachelor of Arts, History, magna cum laude, and German Area Studies August 1985 – May 1989

- *Phi Beta Kappa*; recipient of the Duniway Prize as the most outstanding undergraduate in the Department of History.

REFERENCES

- **Uday Varadarajan**, Principal, Rocky Mountain Institute, San Francisco, CA
  (Tel.: 512-466-3149; Email: uvaradarajan@rmi.org).
- **Peter Augustini**, Vice President, IHS Markit, Cambridge, MA
  (Tel.: 617-866-5124 Email: Peter.Augustini@ihsmarkit.com).

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Exhibit Sierra Club/202
Witness: David B. Posner

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 202

Exhibits Accompanying the Opening Testimony of David B. Posner

The Second Wave of Clean Energy

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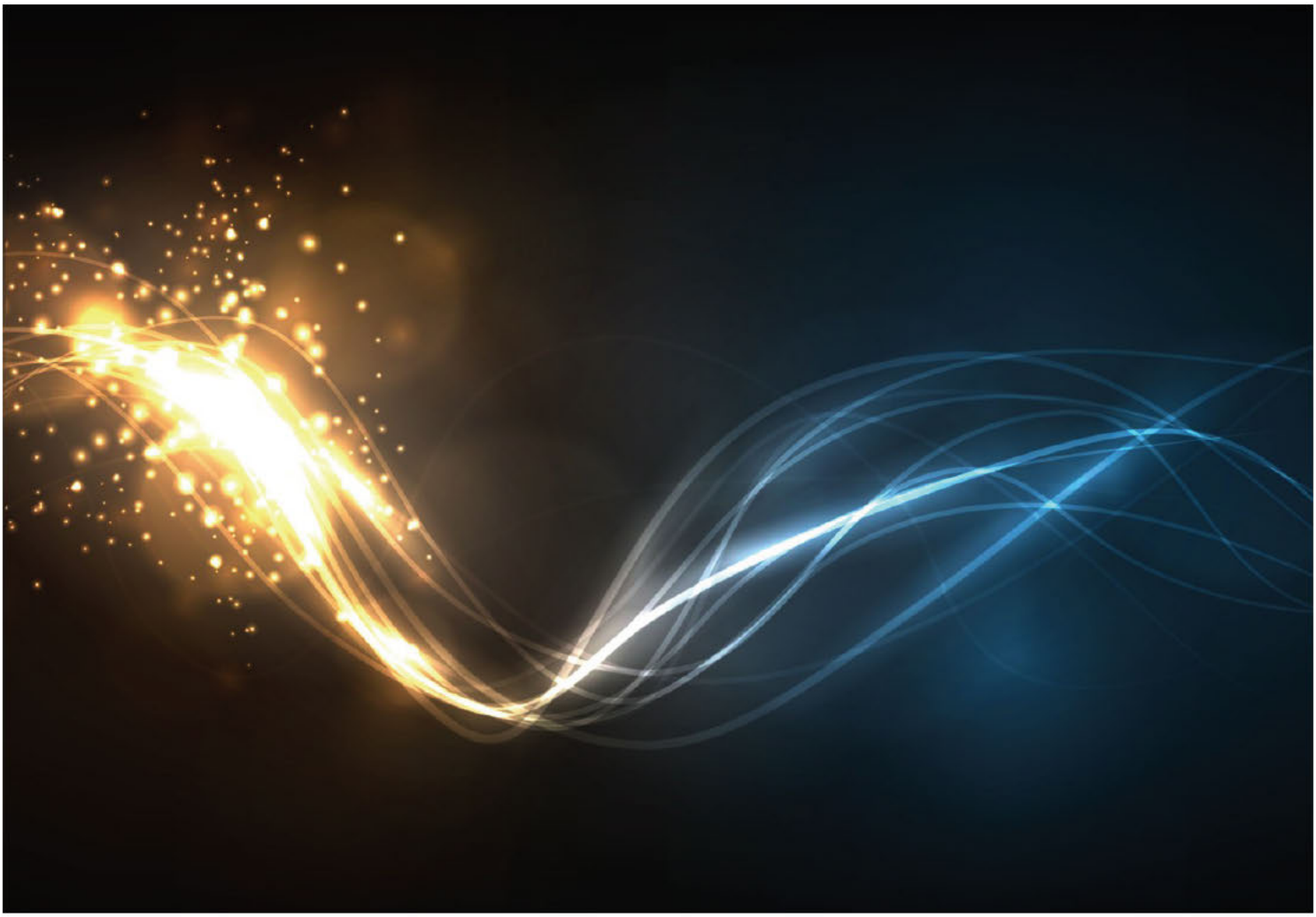
December 10, 2019 05:01 AM GMT

Utilities and Clean Tech | North America

The Second Wave of Clean Energy

We expect a second wave of renewables deployment to drive >70 GWs of additional US coal power plant shutdowns. This trend represents a growth opportunity for many carbon-heavy regulated utilities, and could lead to a 65%+ reduction in greenhouse gas emissions by 2030 vs. 2005.

Sustainability



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For analyst certification and other important disclosures, refer to the Disclosure Section, located at the end of this report.

Contributors



MORGAN STANLEY & CO. LLC
Stephen C Byrd
Equity Analyst
+1 212 761-3865
Stephen.Byrd@morganstanley.com



MORGAN STANLEY & CO. LLC
Devin McDermott
Equity Analyst and Commodities Strategist
+1 212 761-1125
Devin.McDermott@morganstanley.com



MORGAN STANLEY & CO. LLC
Mark Savino
Equity Strategist
+1 212 761-8576
Mark.Savino@morganstanley.com



MORGAN STANLEY & CO. LLC
David Arcaro, CFA
Equity Analyst
+1 212 761-1817
David.Arcaro@morganstanley.com



MORGAN STANLEY & CO. LLC
Ethan C Ellison
Equity Analyst
+1 212 296-5124
Ethan.Ellison@morganstanley.com



MORGAN STANLEY & CO. LLC
Laura Sanchez
Research Associate
+1-212-761-0686
Laura.Sanchez@morganstanley.com



MORGAN STANLEY & CO. LLC
Gustavo Mena
Research Associate
+1 212 761-0179
Gustavo.Mena@morganstanley.com



MORGAN STANLEY & CO. LLC
Janaki Narayanan
Research Associate
+1-212-761-1796
Janaki.Narayanan@morganstanley.com

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Sustainability

Driven by the surprisingly low cost of renewables, we believe that carbon-heavy utilities that have not historically led the pack in clean energy deployment will accelerate their earnings growth by pursuing a "virtuous cycle": shutting down expensive coal plants and investing in cheap renewables. As a result, these "Second Wave Utilities", which all trade at valuation discounts relative to peers, could achieve a valuation re-rating. **We see the largest opportunity for utilities with relatively high carbon-intensive power fleets: AEP, D, SO, PNW, PPL, and DUK.**

ESG interest in the power sector is significant, given the sector's large carbon profile. Common questions we receive concern: 1) the degree to which US utilities are decarbonizing their power plant fleets, 2) how much change to the power generation mix we may see in the future as a result of further renewable energy cost declines, 3) impacts to utility growth and profitability from this movement toward clean energy, and 4) impacts to natural gas demand from the movement toward renewable energy.

As a result, we conducted an in-depth, asset-by-asset assessment of the coal fleet in the US and found that >70 GWs of coal capacity will become economically at risk through the course of the next decade (excluding 24 GWs already scheduled to retire), resulting in coal-fired electricity declining from 27% of total US power in 2018 to just 8% by 2030e. The nationwide benefit to customers from replacing coal-fired power with renewables could be as high as $3-8b/year, we estimate, while at the same time we see a total renewables investment opportunity for utilities of $93-184b. In addition, carbon emissions would plummet under our estimates. Our most likely scenarios would result in a 65-74% reduction in GHG emissions of the US power sector by 2030e (vs. 2005 levels).

North America Industry View

Regulated Utilities	In-Line
Diversified Utilities/IPPS	Attractive
Clean Tech	Cautious

While we project an increased penetration of renewables to drive a 13% decline in US natural gas demand through 2030e, we expect coal demand to decline by ~5x that amount. Despite this pressure on natural gas demand, in the very long term we forecast an important continued role for natural gas in the power sector as these plants can help to "fill in the gaps" when renewable power *output* does not coincide with power *demand*.

What would be the impacts of a tax on carbon emissions? On our estimates: 1) a price on carbon of $40/tCO2e could result in all of US coal plant capacity becoming uneconomic; 2) customers could see bill pressure in carbon-intense regions (the Southeast and Midwest); 3) merchant power companies with high carbon intensities (VST, NRG) could experience declining profitability; 4) there could be greater margins for low-carbon merchants EXC and PEG, and for renewables developers NEE, AES, and RUN. **The biggest beneficiaries, in our view, would be EXC and NEE, while the most negatively impacted would be NRG and VST.**

This is the first of a planned series of reports. We intend to address: 1) the coal at risk in the US on a regional, state, and company level basis, 2) renewable energy economics post the step down in tax credits, 3) the US energy mix by 2030, and 4) implications in greenhouse gas (GHG) emissions of the US power sector. In Part II, we intend to cover company-specific dynamics including capex opportunity and impact in customer bills.

Contents

5 Executive Summary

9 The Foundation of Our Analyses

- 9 Cost of Generation Throughout the US
- 16 Coal at Risk & Implications in the US Power Mix

20 Impacts on the Carbon Intensity of the US Power Sector

- 20 Stock Implications of a Price on Carbon

22 Case Studies — The Shift Away from Coal and Toward Renewable Energy: A Key Growth Opportunity for Utilities

- 23 Case Study #1: NextEra's Acquisition of Gulf Power
- 24 Case Study #2: Xcel's Shift to Renewable Energy
- 26 Case Study #3: The Daniel Coal-Fired Plant in Mississippi

27 Assessing How Utilities Will Compare Coal-Fired Generation Against Renewables

- 27 The "Coal Variable Cost" Approach: Xcel Energy
- 28 The "All-In Cost of Coal" Approach

29 Regional Analysis: Regulated States

- 29 Midwest
- 30 Southeast
- 31 MidAtlantic
- 32 Southwest
- 33 Northwest

34 Regional Analysis: Merchants

- 34 ERCOT (Texas)
- 36 PJM (Mid-Atlantic)
- 38 NYISO
- 40 ISO-NE
- 42 CAISO

44 Appendix — Coal Economics by Regulated State

- 44 Midwest
- 46 Southeast
- 48 MidAtlantic
- 48 Southwest
- 49 Northwest

Executive Summary

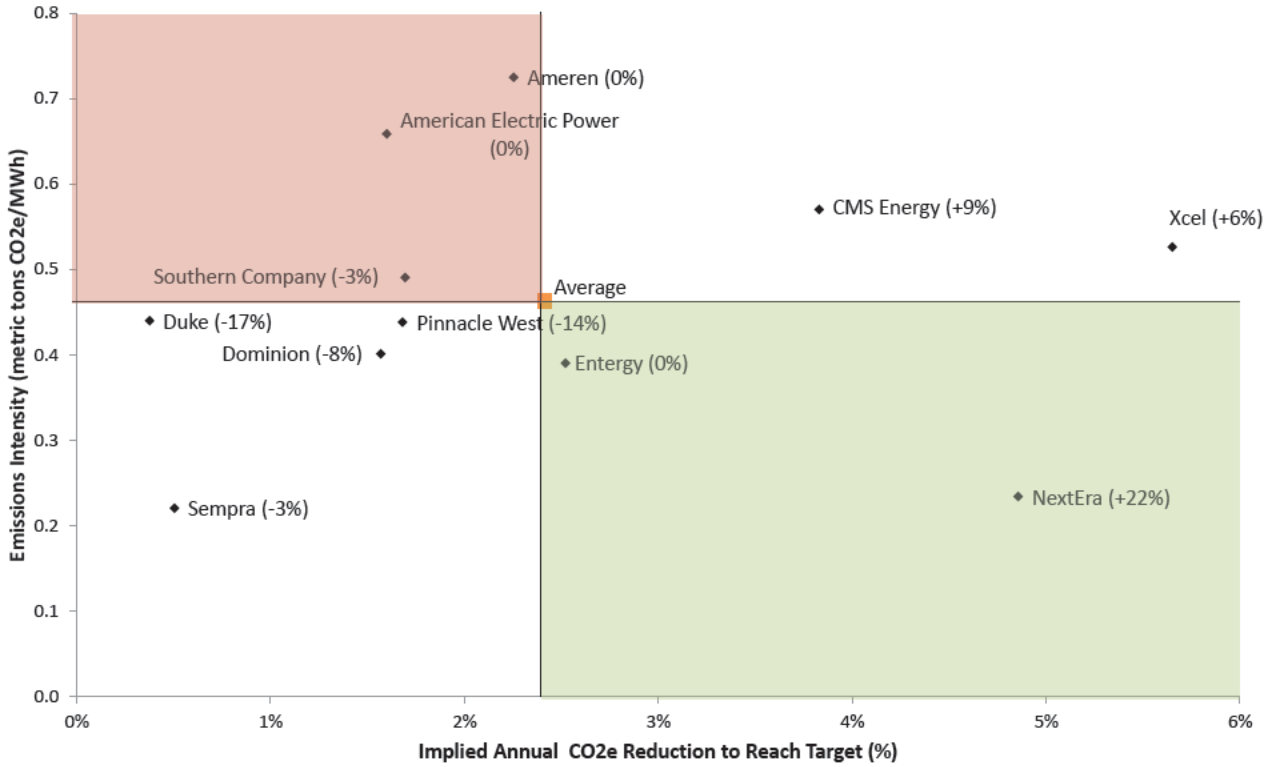
We believe we are at the start of a "second wave" of renewables deployment and coal plant retirements, led by utilities that have historically not been leaders in decarbonization. The economics of renewables have, in our view, become sufficiently attractive to warrant such a shift, and we believe these utilities, which all trade at valuation discounts relative to peers, could achieve faster earnings growth. There is a fascinating correlation (see Exhibit 1), in which utilities with the fastest "rate of change" of carbon intensity trade at valuation premia relative to peers. Why would this relationship exist? We believe the evidence suggests that utilities with greater carbon "rate of change" also have higher EPS growth rates, which in turn is typically driven by more capital being deployed on new renewables and related investments.

We see the largest re-rating opportunity for utilities with relatively high carbon-intensive power fleets: AEP, D, SO, PNW, PPL, and DUK. The fastest growing US utilities are those that are moving most aggressively toward clean energy — including NEE, AES, XEL, AEE, CMS, and SRE, which trade at an average premium of 9% on a 2021e P/E basis. Driving this growth-decarbonization relationship is what we call a "virtuous cycle": In regions with favorable renewable energy resources, a utility can shut down an old, highly depreciated coal-fired power plant, replace the capacity with cheaper and clean resources (likely increasing rate base growth), and recover the remaining rate base of the retired coal plant (which is typically low), all while lowering power bills for customers, and/or creating rate headroom for other investments (another driver of rate base growth).

We believe this "virtuous cycle" will be a major theme in the utility sector over the next ~20 years. NextEra's acquisition of Gulf Power, which we discuss in this note, gives an indication of how beneficial this model can be for investors. Among the utilities with the greatest opportunity to pivot away from coal, we note that AEP and D are in the early stages of a significant move toward renewables, but we also see potential catalysts for SO, PNW, PPL, and DUK.

Exhibit 1:

Emissions Intensity vs. Implied Annual Emissions Reduction & Premium/Discount to Peers on 2021 Valuation Multiples



Source: Company Data, Morgan Stanley Research, Thomson Reuters Pricing as of 11.29.2019. Annual CO2e reduction to reach target calculated as the implied annual reduction in emissions/intensity needed to reach publicly stated CO2 target.

The two remaining (fossil-heavy) pure merchant power stocks (VST, NRG) — which own plants that compete to sell power and do not receive a regulated rate of return — may be negatively impacted by increasingly cheap renewable energy, but the impacts are more complex than investors appreciate. Vistra and NRG own power plant fleets with relatively high carbon intensity levels (i.e., they own a large number of coal and gas power plants), and therefore investors have always seen as significantly at risk from the growth in cheap renewables. That said, in Texas (a windy and sunny state), while cheap renewable energy could put downward pressure on power prices, we see a longer-term mismatch between 1) the volume of renewables available during peak demand periods and 2) increases in power demand due to rapid economic growth in Texas. The result of this mismatch is a decrease in power prices on low-demand days, but an increase in power prices on days with high demand, when renewable energy potentially cannot fully meet this demand. We may also need additional natural gas-fired power capacity in Texas to provide the power needed to fill this "mismatch," and the forward power curve is currently not high enough to provide sufficient returns for a new natural gas-fired power plant. In the medium term, however, we see a potential dampening of upside to ERCOT power prices from the very large volumes of planned solar development (see our note here).

Based on our in-depth, asset-by-asset assessment of the coal fleet in the US, we project that >70 GWs of US coal capacity will become economically at risk through the course of the next decade, resulting in coal-fired electricity declining from 27% of total US power in 2018 to just 8% by 2030. From the companies' perspective, this represents a total renewables investment opportunity of $93-184b, while for customers, we calculate the nationwide benefit from replacing coal-fired power with renewables could be $3-8b/year. In addition, we forecast these coal retirements to drive carbon emissions of the US power sector to decline 65-74% by 2030 (vs. 2005 levels).

The magnitude of coal plant retirements depends on a few critical variables, namely: 1) the magnitude of further renewable energy cost reductions (we have frequently seen greater cost declines than projected for renewables), 2) how utilities conduct their economic assessment of their coal-fired plants versus renewables, and 3) whether there is a price on carbon. In addition, there are numerous practical, locally-determined hurdles to renewables, including availability/cost of real estate and interconnection costs. **Exhibit 2** shows a wide range of potential outcomes, where Scenario 1 represents the most conservative approach and Scenario 5 the most aggressive. We would focus investors on Scenarios 3-5 as being the more likely outcomes, with Scenario 3 representing our base case.

Exhibit 2:
Coal at Risk by 2030e & Implications in Gas Demand & CO2 Emissions Under Various Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Renewables LCOE Scenario	*Bear*	*Midpoint*	*Midpoint*	*Bull*	*Bull*
Variable Only or All-in Costs for Coal?	*Variable Only*	*Variable Only*	*All-in*	*All-in*	*All-in*
Carbon Pricing?	*No*	*No*	*No*	*No*	*Yes, $40/tCO2e*
Coal Capacity at Risk (GW)					
Midwest	0.9	2.6	33.6	61.4	74.0
Southeast	1.2	5.3	20.9	28.9	56.8
MidAtlantic	-	1.0	9.9	15.1	15.1
Southwest	-	-	4.5	5.5	5.5
Northwest	0.1	0.1	0.2	4.5	4.5
PJM	-	-	-	-	25.6
ERCOT	-	-	-	10.6	10.6
Total Capacity at Risk (GW)	**2.2**	**9.1**	**69.2**	**125.9**	**192.0**
Total as % of Current Coal Capacity	*1%*	*5%*	*36%*	*66%*	*100%*
Coal Output at Risk (GWh)					
Midwest	1,973	5,699	73,679	134,420	162,154
Southeast	2,650	11,708	45,862	63,288	124,390
MidAtlantic	-	2,260	21,621	32,992	32,992
Southwest	-	-	9,919	12,067	12,067
Northwest	116	265	500	9,827	9,827
PJM	-	-	-	-	55,970
ERCOT	-	-	-	23,172	23,172
Total Output at Risk (GWh)	**4,740**	**19,933**	**151,581**	**275,766**	**420,573**
Gas-Fired Output (GWh)	**1,225,323**	**1,230,413**	**1,274,520**	**1,316,126**	**1,364,642**
vs. 2018 levels	*-17%*	*-16%*	*-13%*	*-10%*	*-7%*
Total Power Sector CO2 Emissions (mn metric tons)	**982**	**968**	**853**	**744**	**618**
vs. 2005 levels	*-59%*	*-60%*	*-65%*	*-69%*	*-74%*
vs. 2018 levels	*-44%*	*-45%*	*-52%*	*-58%*	*-65%*

Source: SNL Financial, EIA, Morgan Stanley Research estimates. Note: the "Variable or All-In Costs for Coal" refers to different approaches a utility may make in comparing coal-fired power plants to renewables economics — "Variable Only" indicates that only coal plant variable costs are considered, while "All-In" would include fixed coal plant costs in the comparison. The carbon pricing scenario (Scenario 5) is based on a $40/ton carbon price. The capacity identified at risk excludes coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

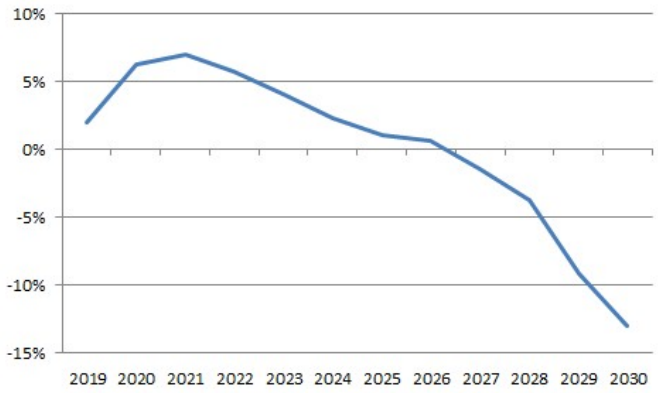
Regional Takeaways

- **We see the greatest coal at risk/opportunity in the Midwest region given favorable wind economics,** with wind Levelized Cost of Electricity (LCOEs) as low as $20/MWh by 2024 (post PTC step down) comparing to the current average all-in cost of coal plants of $30/MWh. Given this dynamic, we see 34 GWs of coal capacity likely at risk by 2030 under Scenario 3, growing to 74 GWs in an scenario with a $40/ton carbon price. Regulated utilities under our coverage that serve the region include AEE, AEP, CNP, CMS, DUK, and XEL.
- **The Southeast is the second region by "transition" potential, driven primarily by favorable solar economics,** with solar LCOEs as low as $30/MWh (post ITC step down) comparing to the current all-in cost of coal plants of $41/MWh on average. We project 21 GWs of coal capacity to be at risk by 2030 under Scenario 3, growing to 57 GWs in Scenario 5. Regulated utilities serving the region include D, DUK, NEE, PPL, and SO.
- **For the Mid-Atlantic, Southwest, and Northwest regions (regulated utilities serving these include AEP, D, FE, and PNW**), we see all coal as being uneconomic relative to our bull renewables LCOEs, even without a carbon tax. We forecast a combined coal capacity at risk of 15 GWs by 2030 in Scenario 3 growing to 25 GW in Scenario 4 and 5, with wind economics being favorable in states like MT, OH, and WV, and solar economics in VA and the Southwest. In the Southwest, we believe PNW may take more aggressive action to deploy solar power and energy storage, and will lay this out in their April 2020 Integrated Resource Plan (IRP). Our math indicates there could be substantial customer benefits from such action.
- **New York (NY-ISO), New England (ISO-NE), and California (CAISO) generate electricity with zero, or close to zero, coal.** The Northeast has begun an aggressive move toward offshore wind, while California is one of the national leaders in the deployment of a combination of renewable energy and energy storage (offshore wind is challenging off the West Coast due to water depth).

We project that, from 2020 to 2030, natural gas demand to fuel power plants will initially increase but ultimately decline by ~13% in total. While we project meaningful declines in US natural gas demand through our 2030 forecast period due to the growth in renewable energy, the biggest negative impacts will in our view be experienced by the coal power plant fleet, which we forecast in Scenario 3 could decline by as much as 72% in 2020-30. Why? Coal-fired power plants are in general significantly more expensive than the existing fleet of natural gas-fired power plants, and as a result, it is the coal power plant fleet that will suffer the most downside from the growth in renewable energy. **In the very long term (beyond 2030), we forecast an important continued role for natural gas in the power sector, albeit with reduced demand levels.**

Exhibit 3:

We project a cumulative 13% decline in power sector natural gas consumption by 2030

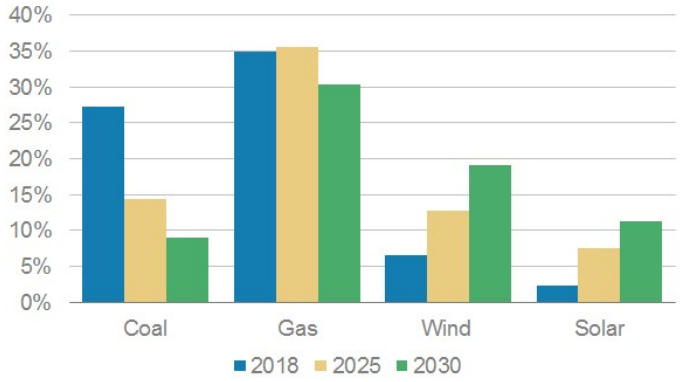


Source: Morgan Stanley Research estimates.

An example of this dynamic would be XEL, a large Midwestern utility that is rapidly moving toward wind and solar power. XEL projects that natural gas will decline as a percentage of its power, from 29% in 2018 to 15% in 2030. Additionally, NextEra Energy has outlined the economics of renewables and natural gas driving the retirements of existing coal plants. We would expect Florida Power & Light to completely replace its coal power and partially replace other energy generation sources pirmarily with solar power by 2030. We expect the solar generation mix to grow by ~1,500bps and the gas generation mix to fall by ~1,000-1,500bps by 2030.

Across the US, we forecast a rapid transition away from coal-fired generation and toward clean energy. Exhibit 4 shows our projected change to the sources of power generation in the US:

Exhibit 4:
We forecast that coal-fired electricity will decline as a % of US generation from 27% in 2018 to just 8% in 2030. Over that same time period, wind and solar will grow from 9% of the mix to 30%



Source: Morgan Stanley Research estimates.

What would be the impacts of a tax on carbon emissions? The biggest beneficiaries would be EXC and NEE, while the most negatively impacted would be NRG and VST, in our view. We would likely see 1) a significantly more rapid movement away from coal-fired power (carbon taxes greatly increase coal plant fuel costs) and toward renewables, 2) potential customer bill pressure in carbon-intense regions (the Southeast and Midwest), 3) declining profitability for merchant power companies with high carbon intensities (VST, NRG), and 4) greater margins for low-carbon merchants EXC and PEG, and for renewables developers NEE, AES, and RUN.

How could we be wrong? Given the breadth and depth of our analysis, we acknowledge the challenges in accurately predict the decision-making behavior of utilities. Key potential ways we could be wrong: 1) practical, locally-driven hurdles to renewables, including availability/cost of real estate and interconnection costs (as appears to be the case in Virginia with respect to solar power, driving Dominion to pursue relatively expensive offshore wind); 2) more rapid than expected growth in natural gas infrastructure (e.g., the Atlantic Coast Pipeline) that brings very low-cost natural gas to coal-heavy regions, driving a decision to pursue greater natural gas power plant development; and 3) utility concerns with the reliability and resiliency of the grid, driving greater than expected estimates of the costs of grid enhancement (e.g., storage) in conjunction with renewables growth. On the other hand, we may be underestimating the growth in renewables if 1) in the future, the federal government imposes greater regulation on coal-fired plants and proposed natural gas pipelines; 2) natural gas prices rise, due to drivers such as greater regulation of fracking and lack of permitting natural gas extraction on federal lands; and 3) greater state-level resistance to building additional natural gas-fired power plants (such as we have recently seen in several states — an example is in Michigan, as per the order found here).

In the following sections we cover:

- **The Foundation of Our Analyses,** where we detail our methodology on renewables LCOEs, gas new builds, and coal economics.
- **Impacts on the Carbon Intensity of the US Power Sector,** where we calculate the impact on CO_2 emissions from this second wave to clean energy and the impacts on utility stocks of a price on carbon.
- **Case Studies — The Shift Away from Coal and Toward Renewable Energy: A Key Growth Opportunity for Utilities,** where we look into NEE's "virtuous cycle" approach, XEL's shift to renewable energy, and joint ownership structures of coal plants by utilities with differing decarbonization strategies, such as the Victor J. Daniel coal-fired plant in Mississippi, co-owned by NEE and SO.
- **Assessing How Utilities Will Compare Coal-Fired Generation Against Renewables,** where we contrast two approaches: XEL's variable-only approach, and NEE's virtuous cycle using an all-in cost of coal approach.
- **Regional Analysis: Regulated States,** where we dive deep into the economics of coal in regulated regions (Midwest, Southeast, MidAtlantic, Southwest, and Northwest).
- **Regional Analysis: Merchants,** where we look into the economics of coal in PJM and ERCOT, as well as the energy progress and goals of NY-ISO, ISO-NE, and CAISO.

The Foundation of Our Analyses

In 2018, the amount of power produced by coal-fired power plants in the US was ~40% lower than the amount of power produced by coal-fired power plants in 2005, having a significant impact in the intensity of the US carbon sector, with CO_2 emissions declining by 27% in 2018 from 2005 levels. **The decline in coal-fired electricity, and consequently in CO_2 emissions, has been driven by the aggressive drop in renewables costs and natural gas prices, dynamics that we project will continue during the next decade and beyond.**

The core focus of our analysis is centered on answering one central question: how much of a decrease in power output from coal-fired power plants will we see in the future? In this section, we walk through the results of our analysis of the costs of operating different types of power plants (wind, solar, gas, and coal), the amount of coal (capacity and output) deemed at risk under various scenarios, and the implications in gas demand. In subsequent sections we assess this dynamic on a region-by-region basis.

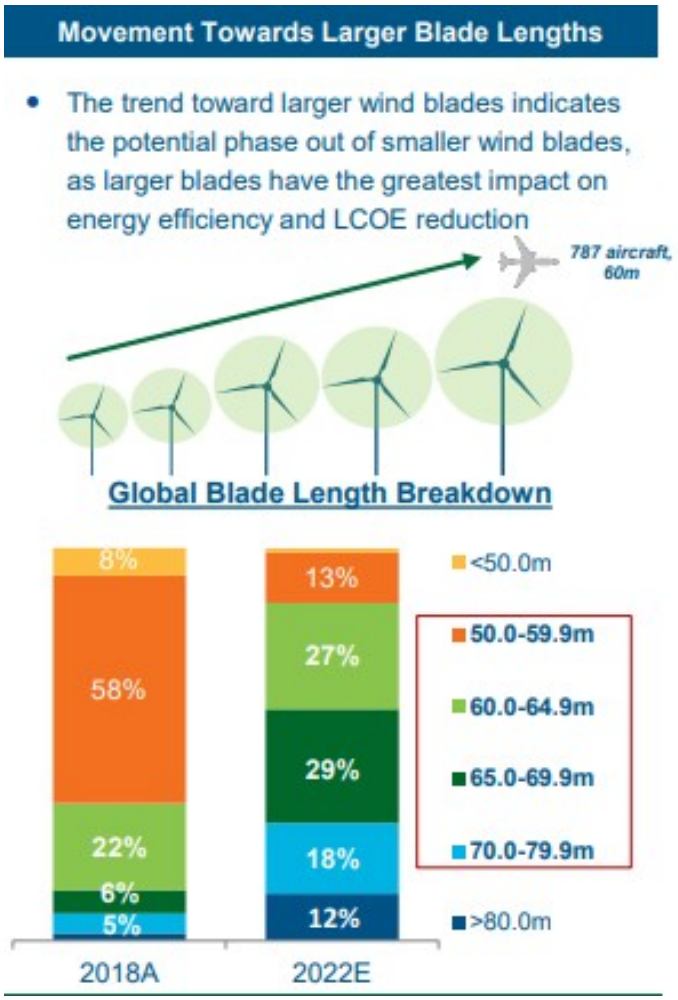
We will frequently reference levelized cost of electricity (LCOE), which is the net present value of the unit-cost of electrical energy over the lifetime of a generating asset. This metric is often taken as a proxy for the average price that the generating asset must receive in a market to break even over its lifetime. It is an economic assessment of the cost competitiveness of an electricity-generating system that incorporates all costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital.

Cost of Generation Throughout the US

The Cost of Wind Power

The rapid cost declines in wind power are driven in part by a simple, yet powerful, mathematical equation: The area of a circle is a function of the square of the circle's radius. For a wind turbine, the "radius" is the wind blade, and as the wind bade increases in length, the power output of a wind turbine increases exponentially. **Exhibit 5** , from TPI Composites (TPIC), shows the increases in wind blade length over time, a trend we expect will continue for many years to come:

Exhibit 5:
The market movement toward larger blades will continue for many years



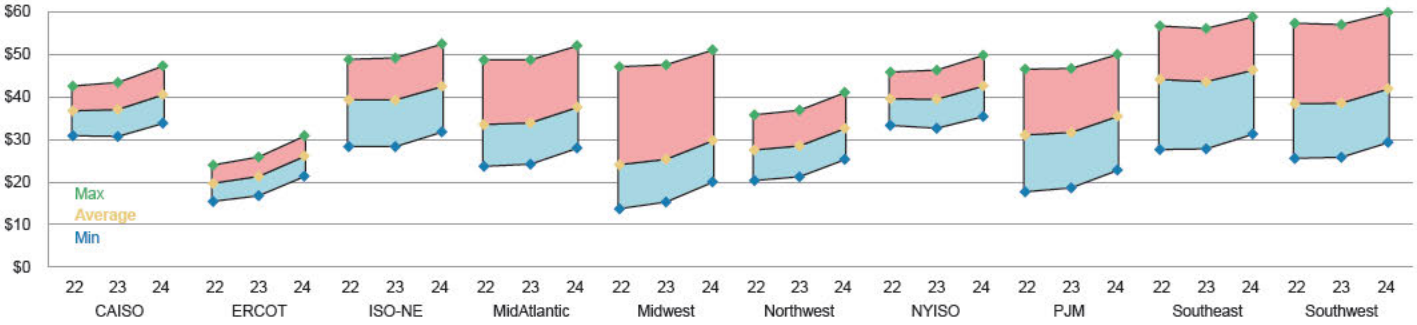
Source: TPI Composites company data and estimates.

Our wind LCOE analysis is built from our wind economics model (please ask us for a copy) in which we flex several inputs to reflect regional differences in capacity factor, installed system cost, and O&M, among other factors. We explore state-by-state and/or annual differences in:

- Build Cost ($/kW)
- Debt/Equity ratio and different costs of capital
- Capacity Factor
- Operating expenses ($/MWh)
- Capacity price / capacity value
- Production Tax Credit (PTC) value

Exhibit 6:

Wind Levelized Cost of Energy (LCOE), by Year and by Region



Source: Morgan Stanley Research estimates. Note that ISO-NE, NYISO, and PJM LCOE is presented net of an assumed capacity payment.

We developed a range of wind LCOEs, based on more and less aggressive assumptions regarding the variables previously described. We would note that, historically, wind cost reductions have exceeded our estimates.

Exhibit 7:

LCOE Output from Regional Wind Modeling, 2022-24

	2022	2022	2022	2023	2023	2023	2024	2024	2024
Region	Min	Average	Max	Min	Average	Max	Min	Average	Max
CAISO	$30.91	$36.74	$42.58	$30.74	$37.08	$43.42	$33.84	$40.59	$47.33
ERCOT	$15.44	$19.70	$23.96	$16.80	$21.36	$25.91	$21.40	$26.15	$30.90
ISO-NE	$28.34	$39.32	$48.86	$28.34	$39.33	$49.19	$31.82	$42.54	$52.51
MidAtlantic	$23.69	$33.54	$48.73	$24.22	$33.95	$48.73	$28.03	$37.64	$52.07
Midwest	$13.72	$24.07	$47.12	$15.32	$25.37	$47.59	$20.07	$29.81	$51.10
Northwest	$20.37	$27.55	$35.80	$21.26	$28.52	$36.89	$25.36	$32.67	$41.09
NYISO	$33.35	$39.60	$45.86	$32.66	$39.49	$46.32	$35.43	$42.64	$49.85
PJM	$17.70	$31.07	$46.54	$18.65	$31.69	$46.72	$22.84	$35.51	$50.04
Southeast	$27.66	$44.16	$56.70	$27.82	$43.63	$56.13	$31.30	$46.36	$58.85
Southwest	$25.59	$38.44	$57.35	$25.84	$38.57	$57.04	$29.36	$41.96	$59.92

Source: Morgan Stanley Research estimates. 2024 assumes zero Production Tax Credit (PTC) value. Note that ISO-NE, NYISO, and PJM LCOE is presented net of an assumed capacity payment.

To estimate state-by-state capacity factors, we sourced information from the Department of Energy (DOE), which publishes average capacity factors by region, and also the range of capacity factors within a region and specific time frame. Our baseline 2019 capacity factors were derived using the following methodology — scaling up capacity factors from the map in **Exhibit 8** (as this chart shows average capacity factor in the state, and for project vintages 1998-2017), using the range of individual project capacity factors (+/- 10%) in **Exhibit 9** , to highlight the most economic regions within each state (assuming that this is where wind projects would most likely be built) and rebase figures that include older project vintages.

Exhibit 8:

Average 2018 Capacity Factors by State, 1998-2017 Projects

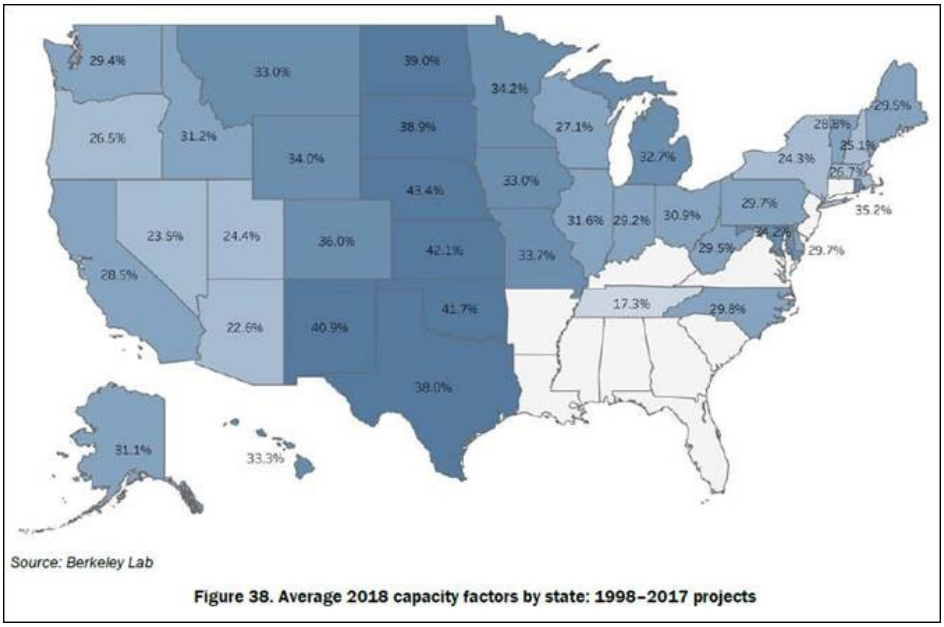


Figure 38. Average 2018 capacity factors by state: 1998–2017 projects

Source: Berkeley Lab, DOE.

Exhibit 9:

Calendar Year 2018 Capacity Factors by Region, 2014-17 Projects

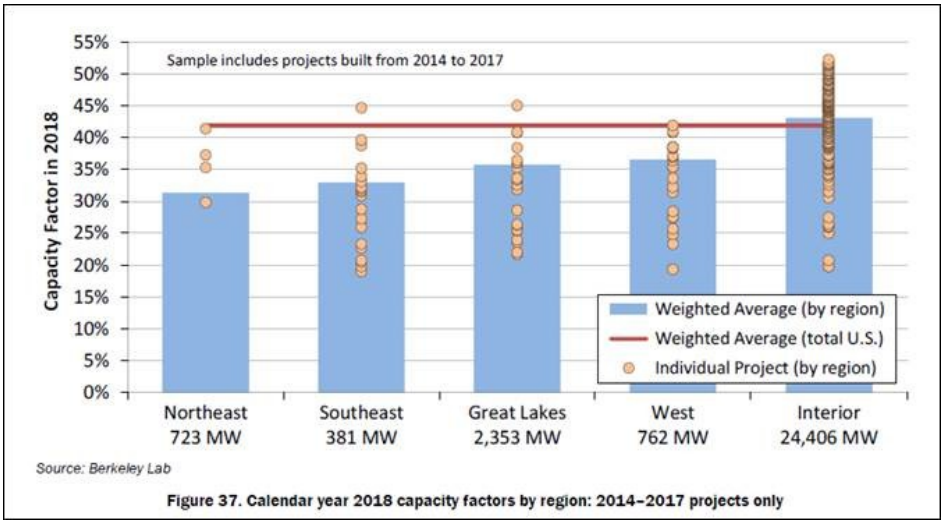


Figure 37. Calendar year 2018 capacity factors by region: 2014–2017 projects only

Source: Berkeley Lab, DOE.

To forecast future changes in capacity factors, we experimented with a wind performance model we created to understand the improvement in production that corresponds with an increase in turbine blade length (a function of Πr^2). In this analysis, we have assumed that average blade length for new wind projects will increase from the 2018 fleet average of ~58m, to ~73m for 2024 installments. This is a significant technological change, but we are already seeing these >70m blades being deployed in the field. We have estimated that this increase in blade length can drive an 8-12% (bear - bull) improvement in capacity factor, such that in the regions of the US with the greatest wind resource we may see onshore wind capacity factors reach 60% by 2024 (2014-17 projects exhibited capacity factors as high as ~54%).

To estimate state-by-state wind system capital costs, we started with a regional breakdown of capital cost by technology type from the Energy Information Administrations (EIA). The *total overnight capital costs* for onshore wind by region includes locational adjustments to account for additional costs associated with accessing remote wind resources (eg. wind sites located near existing transmission with access to a road network or are located on lower development cost lands are generally built up first, after which additional costs may be incurred to access sites with less favorable characteristics). Other region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions and variation in labor and other construction costs through the country. From this data set, we made our own adjustments to incorporate commentary directly from our conversations with wind developers, who have shared that in the best regions for

wind development, capital costs are currently $1,100-1,200/kW. We also backed into this range by taking turbine price data from Bloomberg New Energy Finance (BNEF) which quotes current turbine costs at ~$790/kW in the US. Then, given that the National Renewable Energy Laboratory (NREL) has found that ~68% of total installed system cost for wind is the cost of the turbine (the rest is balance of system and financial costs), we arrive at an all in figure of ~$1,160/kW. We rebased the regional capital costs from EIA such that the capital cost in the best regions was ~$1,160, while maintaining the regional cost shaping.

To forecast future changes in capital cost, we considered the rate at which install costs have declined over the last several years. Based on conversations we have had with developers, we believe that $/kW install cost has declined at ~6%/year in 2012-18 (with the lowest cost projects falling from $1,800/kW in 2012 to <$1,200 currently). Our bull case assumptions assumes that future installed cost reductions will continue at this rate between now and 2024. Much of the cost reduction will be in the balance of system costs — roads, foundations, interconnections, and we assume some future price reductions in turbines as well. Many of our recent conversations with wind developers have centered on how they will continue to pull install / O&M cost out of the business in order to minimize the impact of sunsetting PTC. In total, this bull case assumption drives an additional ~30% decrease in installed system cost by 2024. In the bear case assumption we model cost declines at half of the historic rate, or ~2.8%/yr.

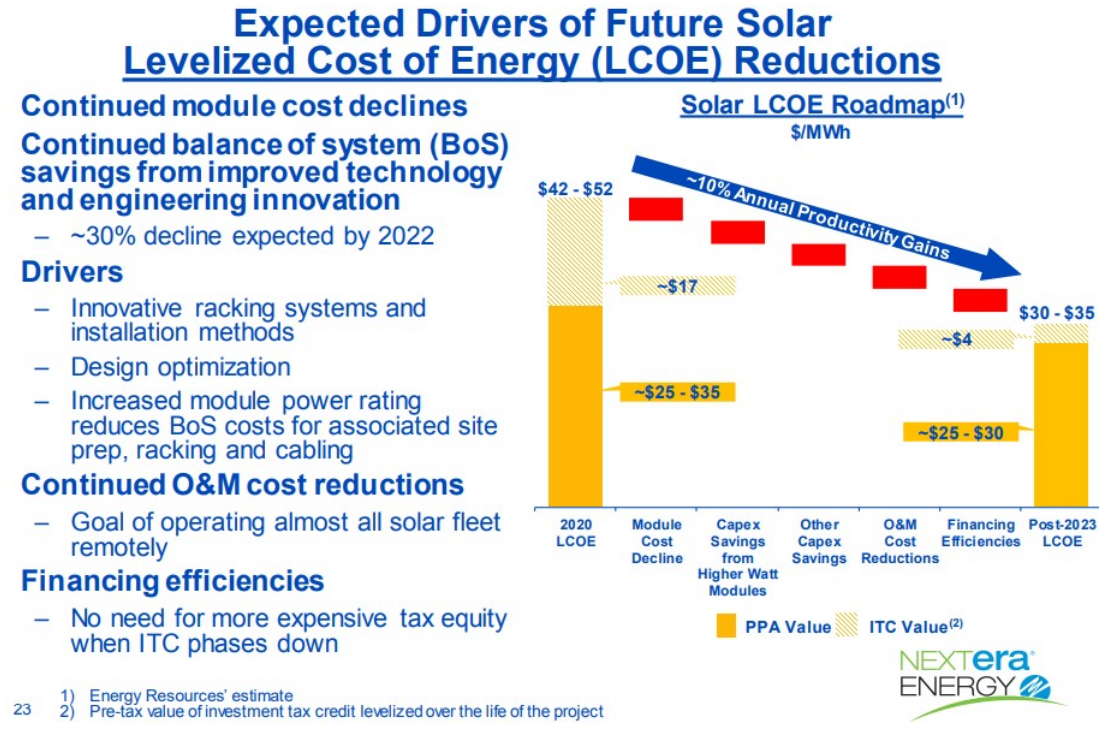
Future reductions in wind farm operating cost was also a key assumption in our LCOE modeling. The same NREL study shows that the average land-based wind project in 2017 carried ~$12/MWh of operating and maintenance (O&M) costs. Wind developers have shared that O&M costs have fallen ~25% over the last four years, and in our bull case assumption we extend this trajectory through 2024 to get to a $7/MWh level (which is consistent with the lower end of the range NREL published in 2017). In our bear case assumptions we assume operating costs remain at $12/MWh by 2024.

The Cost of Solar Power

We forecast continued cost declines in solar system costs through increased competition, equipment improvements, installation efficiencies, and technical advantages. It is clear in our conversations with solar developers and installers that 1) competition and 2) economies of scale through manufacturing efficiencies, especially in China, continue to drive global solar module costs lower. Drivers of cost declines for the rest of the system (Balance of System, or BoS) include opportunities to heighten efficiencies around installation methods, such as through more efficient racking systems or system design optimization.

Exhibit 10:

NextEra Energy targets Post-2023 $30-35 LCOEs for solar driven by capital, operating, and financial efficiencies



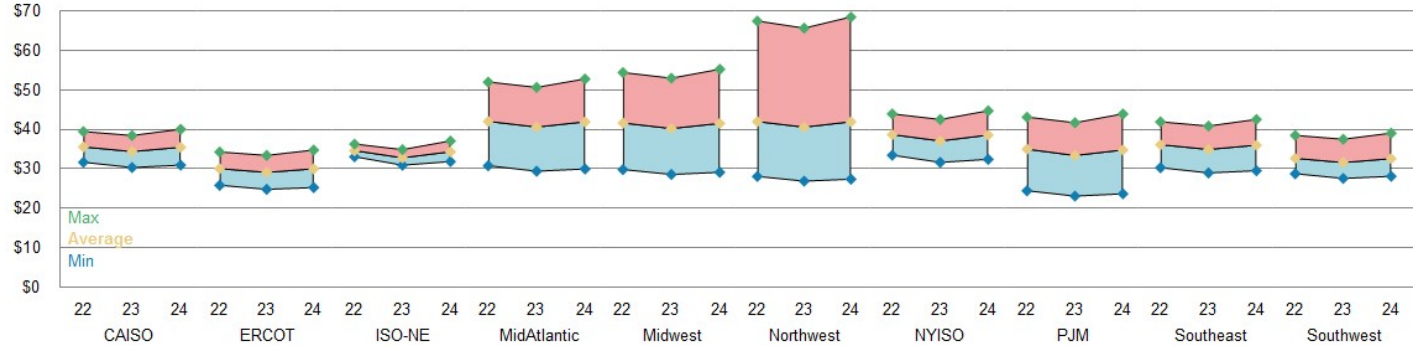
Source: NextEra Investor Presentation

Our solar LCOE analysis is built from our solar economics model (please ask us for a copy) where we manipulated varying assumptions such as capital costs, O&M expense, and capacity factors, to examine bull and bear case LCOE outcomes in each year and in each state, in the 3 years 2022-24. We flexed state by state and/or annual differences in the below factors and like our wind LCOE analysis, developed a range of solar LCOEs based on more or less aggressive assumptions for each:

- Build Cost ($/kW)
- Debt/Equity ratio and different costs of capital
- Capacity Factor
- Operating expenses ($/mWh)
- Capacity price / capacity value
- Investment Tax Credit (ITC) value

Exhibit 11:

Solar Levelized Cost of Energy (LCOE), by Year and by Region



Source: Morgan Stanley Research estimates. Note that ISO-NE, NYISO, and PJM LCOE is presented net of an assumed capacity payment.

We'd note that like with wind, solar cost reductions have historically exceeded our estimates.

Exhibit 12:

LCOE Output from Regional Solar Modeling, 2022-24

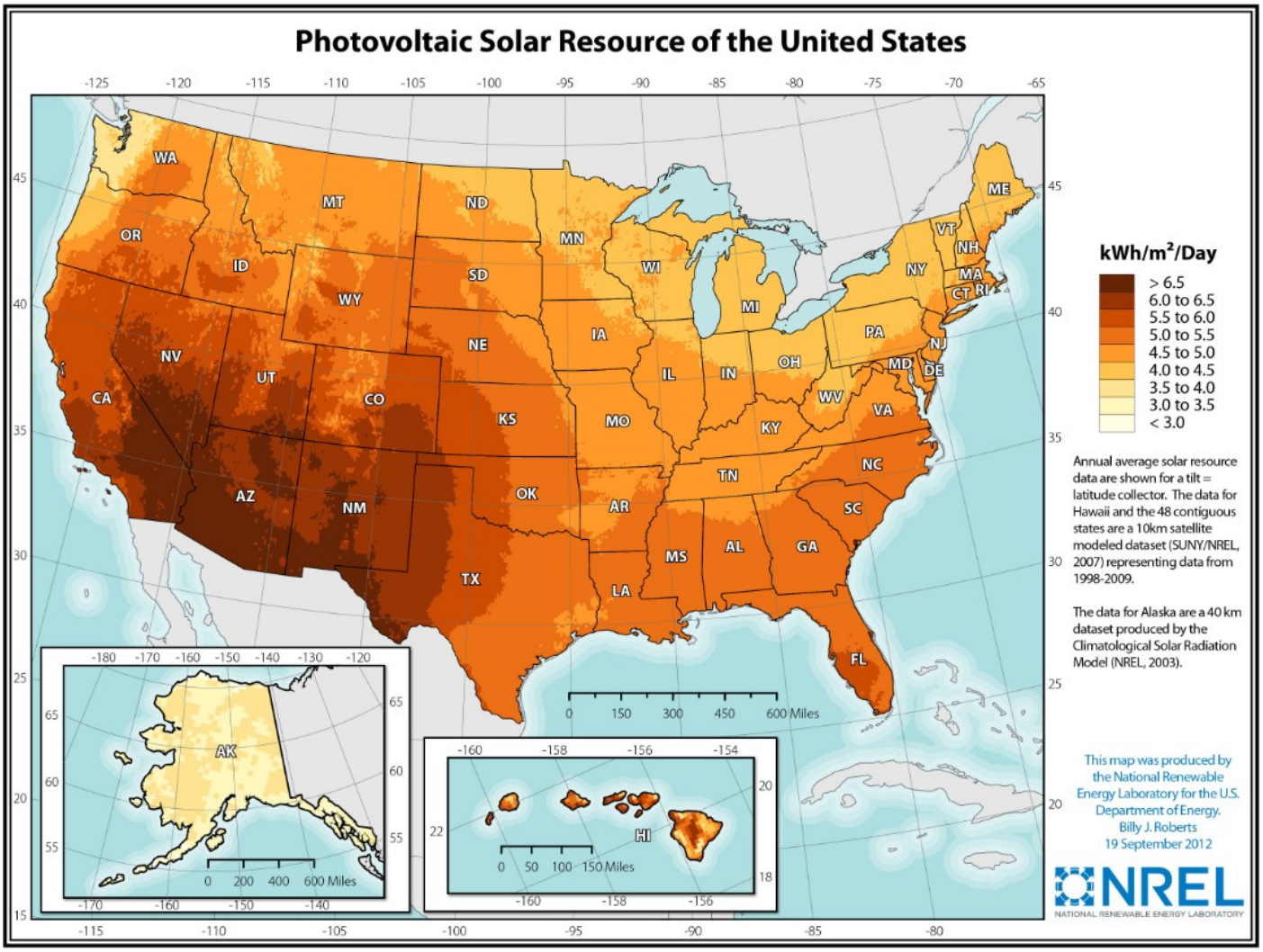
	2022	2022	2022	2023	2023	2023	2024	2024	2024
Region	Min	Average	Max	Min	Average	Max	Min	Average	Max
CAISO	$31.67	$35.57	$39.46	$30.36	$34.41	$38.46	$30.94	$35.49	$40.04
ERCOT	$25.83	$30.06	$34.28	$24.81	$29.12	$33.42	$25.27	$30.02	$34.77
ISO-NE	$33.07	$34.61	$36.29	$30.93	$32.82	$34.89	$31.85	$34.35	$37.08
MidAtlantic	$30.80	$42.04	$52.03	$29.41	$40.61	$50.68	$29.97	$41.92	$52.81
Midwest	$29.82	$41.65	$54.45	$28.60	$40.24	$53.03	$29.14	$41.54	$55.26
Northwest	$28.07	$41.99	$67.51	$26.89	$40.60	$65.72	$27.39	$41.94	$68.53
NYISO	$33.46	$38.70	$43.93	$31.66	$37.09	$42.53	$32.41	$38.57	$44.72
PJM	$24.43	$34.98	$43.14	$23.10	$33.39	$41.71	$23.66	$34.81	$43.95
Southeast	$30.28	$36.13	$41.94	$28.97	$34.93	$40.86	$29.52	$36.02	$42.55
Southwest	$28.77	$32.67	$38.50	$27.58	$31.61	$37.52	$28.10	$32.60	$39.06

Source: Morgan Stanley Research estimates. 2024 assumes 10% Investment Tax Credit (ITC) value. Note that ISO-NE, NYISO, and PJM LCOE is presented net of an assumed capacity payment.

To estimate state-by-state capacity factors, we referenced a US photovoltaics map from the National Renewable Energy Laboratory (NREL), which provides a range of solar resource strength by state for fixed tilt systems, as measured in kWh/m²/day. We used the capacity factor implied by the low end of a state's potential solar resource as our bear case in a given year. For the bull case, we assume a 1-axis tracker is used, which enables higher capacity factors, and multiplied the high end of a state's potential resource by 20%. We used a fixed-tilt bull case capacity factor for states in the Northeast that we felt would be less likely to install 1-axis tracker systems due to lack of land availability. We don't expect significant changes to solar capacity factors through 2024 based on technology improvements (since these are focused on cost and panel efficiency), and thus keep these factors constant throughout those years.

Exhibit 13:

State by State Solar Resource Strength, as measured in kWh per meters-squared/Day



Source: NREL

To estimate state-by-state solar system capital costs, we started with the sum of current solar module and BoS (Balance of System) costs. Though today US module and global module prices differ, we believe module costs in 2022-24 will converge to the global module price, and decrease further. We use the global solar module price as of 2Q19 ($0.28/W) as a starting point for modules, and a BoS cost of $0.55/W informed by the 3Q19 Solar Energy Industries Association (SEIA) report. We then applied regional adjustment factors to each state provided by the US Energy Information Administration (EIA). These factors aggregate EIA's estimated impacts to capital costs of factors such as labor wages and productivity. Lastly, we applied a DC-to-AC conversion factor of 1.36 for 1-axis tracker systems, and 1.30 for fixed tilt systems, from NREL's November 2018 US Solar Photovoltaic System Cost Benchmark. Before regional cost shaping, we arrive at a current capital cost of $1,170/kW for fixed tilt systems and $1,224/kW for 1-axis tracking systems.

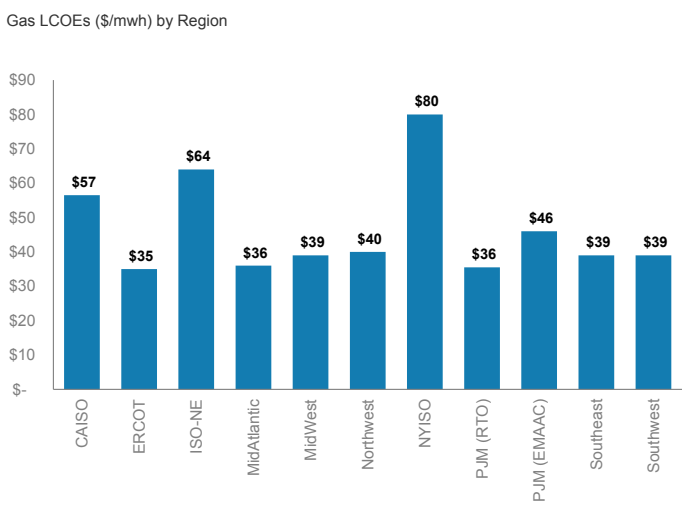
To forecast future changes in capital cost, we considered the potential decrease in modules and BoS costs separately. Though there is currently a disconnect between global and US solar module prices, we believe that gap will close and US module costs will converge to global module costs, which will decrease ~35% further by 2024. We flexed system cost declines in the bear and bull case, assuming system costs would decline by 20% in the bear case and 30% in the bull case (in line with NextEra Energy's projections, who we regard as a best in class renewables developer).

Other key assumptions in our LCOE modeling were operating expenses and Investment Tax Credit (ITC) applications. Based on our conversations with developers, we assume a $7/MWh Operating expense level for tracker systems and $5.5/MWh for fixed tilt systems as a starting point. We assume that operating costs for both systems will decline by 25% by 2024, just shy of NextEra's 30% targeted operating cost decline over the next four years, which it believes is achievable through operating almost all of its solar fleet without on-site personnel. While the solar ITC steps down to 26% in 2020, 22% in 2021 and 10% in 2022 and beyond, through safe harboring we assume solar projects built in 2022 and 2023 can still benefit from a 26% and 22% solar ITC, respectively, before the benefit decreases to 10% in 2024 and beyond.

The Cost of Natural Gas-Fired Generation

The required revenue for a new, state-of-the-art combined cycle natural gas-fired power plant is relatively uniform across the US, but can differ based on 1) different local prices of natural gas, 2) construction cost which is in large part driven by regional differences in labor costs and the delivered cost of components, and 3) regional carbon pricing (Cap-and-trade program in CA and Regional Greenhouse Gas Initiative or "RGGI" in the Northeast). We have developed a regional model that looks at gas-fired LCOEs. Below is an example of the resulting revenue requirements by region, using Morgan Stanley's regional natural gas price forecasts:

Exhibit 14:
2023e gas LCOEs ($/mwh) are relatively uniform, but higher in regions with high natural gas prices, regional carbon pricing and high labor/ construction costs



Source: Morgan Stanley Research estimates. Note that ISO-NE, NYISO, and PJM LCOEs are presented net of an assumed capacity payment.

We project that, in most markets, existing natural gas-fired generation will have lower operating costs than coal-fired plants in the same region. For example, a gas-fired plant will typically have fewer than 20 employees, while a coal-fired plant will often have over 100 employees. The fixed cost of a typical gas fired combined cycle plant, at $15/kW-yr, is significantly lower than that of an average coal-fired plant with capacity of >100 MW, at $29/kW-yr. In addition, the variable cost of a gas-fired plant, at <$20/MWh using Morgan Stanley's natural gas price forecast, is well below the average large coal-fired plant, at ~$30/MWh. As a result, as renewables growth continues in the US, coal-fired generation will be the most likely to shut down, rather than existing natural gas-fired generation.

Our gas LCOE analysis is built from our gas economics model (please ask us for a copy). We adjusted varying assumptions such as capital costs, O&M expense, and natural gas basis to derive LCOEs for gas new builds in 2023. We expect the LCOEs beyond 2023 to rise with inflation as we view the combined cycle generation technology as a mature technology. Our analysis was also based on Morgan Stanley's long-term Henry Hub gas forecast of $2.50. Note that the Morgan Stanley bear case of $2.25 drives the LCOE lower by ~$2/MWh and the bull case of $3.00 drives the LCOE higher by ~$4/

MWh. We flexed state by state and/or annual differences in the below factors:

- Build Cost ($/kW)
- Debt/Equity ratio and costs of capital
- Capacity Factor
- Operating expenses (embeds regional carbon pricing — CA and RGGI)
- Morgan Stanley's long-term Henry Hub gas forecast of $2.50
- Natural gas basis by regions

The Cost of Coal-Fired Generation

The cost of coal-fired generation in the US varies widely, driven primarily by differences in scale and fuel costs. We use the following inputs in analyzing coal units costs:

- **Fuel costs:** Coal costs (based on Morgan Stanley commodity forecasts through 2020, adjusted for inflation thereafter) + coal transportation costs (as per EIA and adjusted by inflation) + a price on carbon for plants in states that are part of the Regional Greenhouse Gas Initiative (RGGI) in the northeast and mid-atlantic.
- **Variable O&M costs:** As reported to EIA in 2018 and adjusted for inflation thereafter.
- **Fixed costs:** Based on 2018 costs reported to EIA and adjusted for inflation thereafter. For merchant plants in PJM we include a $10/MW-day penalty fee related to unplanned outages.
- **Capacity factors:** We use the units' last 3-year average for regulated plants, 55% for merchant plants running around-the-clock, and 45% for merchant plants running during on-peak times only.

What to compare coal against to depends on whether the coal plant is a regulated or a merchant asset. For regulated plants, we compare coal costs to renewables economics in the same state. As we address later in this note, there are two approaches a utility may consider in comparing coal-fired power plants to renewables: 1) the "Variable Only" approach, which indicates that only fuel plus variable O&M costs are considered (which we use in our Scenario 1 and 2), and 2) the "All-in" approach, which includes fixed coal plant costs in the comparison. We use approach #2 in Scenarios 3-5, which in our view are more likely outcomes. In these scenarios, we consider a plant to be uneconomic and therefore "at risk" if the all-in costs are above renewables LCOEs in the same state.

Exhibit 15:

2030 Variable Only & All-in Coal Costs by Regulated Region

	Approach 1: Varible Only Costs		Approach 2: All-in Costs	
	Low End	High End	Low End	High End
Midwest	$20.34	$37.90	$25.54	$49.88
Southeast	$22.51	$37.67	$27.92	$57.16
MidAtlantic	$29.01	$32.44	$34.98	$42.81
Southwest	$23.96	$30.20	$30.66	$43.00
Northwest	$23.23	$33.63	$28.21	$43.14

Source: SNL Financial, EIA, Morgan Stanley Research estimates. Note: Our analysis excludes coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%..

For merchant plants, where operators bid in plants at their dispatch costs (fuel + variable O&M), we use power prices and capacity prices (when available) to determine whether a plant is uneconomic. We calculated on an asset-by-asset basis if energy revenues (arrived at using forecasted power prices from our own dispatch models for PJM and ERCOT) plus capacity revenues (for PJM) were sufficient to cover the plants' all-in costs. If a plant isn't able to break-even, we consider it uneconomic and therefore, "at risk."

Coal at Risk & Implications in the US Power Mix

We assessed the cost of coal-fired power plants on an asset-by-asset basis under five scenarios that show a combination of what we consider are key critical variables: 1) future renewable cost declines, 2) whether utilities/regulators factor in all coal costs or variable costs only, and 3) whether there is a price on carbon. **Exhibit 16** shows the potential outcomes, where Scenario 1 represents the most conservative approach and Scenario 5 the most aggressive one. We would focus investors on Scenarios 3-5 as being the more likely outcomes.

We forecast 70-190 GWs of coal to be economically at risk under what we consider are the most likely scenarios, Scenarios 3-5. This excludes the 24 GWs of coal capacity already scheduled to retire (3 GWs in merchant capacity and 21 GWs in regulated capacity).

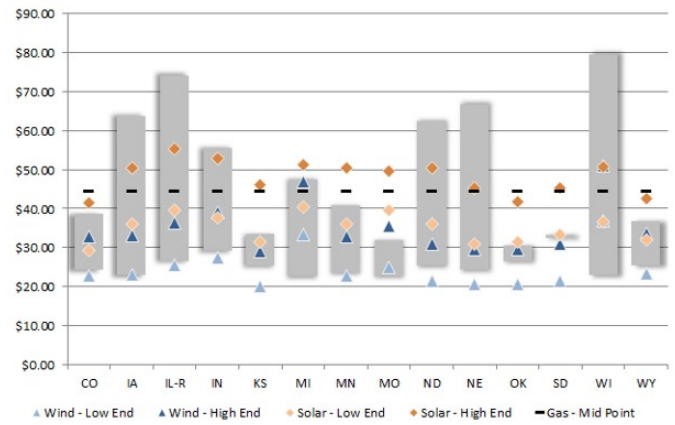
Exhibit 16:
Coal at Risk & Implications in Gas Demand & CO2 Emissions by 2030 Under Various Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Renewables LCOE Scenario	*Bear*	*Midpoint*	*Midpoint*	*Bull*	*Bull*
Variable Only or All-in Costs for Coal?	*Variable Only*	*Variable Only*	*All-in*	*All-in*	*All-in*
Carbon Pricing?	*No*	*No*	*No*	*No*	*Yes, $40/tCO2e*
Coal Capacity at Risk (GW)					
Midwest	0.9	2.6	33.6	61.4	74.0
Southeast	1.2	5.3	20.9	28.9	56.8
MidAtlantic	-	1.0	9.9	15.1	15.1
Southwest	-	-	4.5	5.5	5.5
Northwest	0.1	0.1	0.2	4.5	4.5
PJM	-	-	-	-	25.6
ERCOT	-	-	-	10.6	10.6
Total Capacity at Risk (GW)	**2.2**	**9.1**	**69.2**	**125.9**	**192.0**
Total as % of Current Coal Capacity	*1%*	*5%*	*36%*	*66%*	*100%*
Coal Output at Risk (GWh)					
Midwest	1,973	5,699	73,679	134,420	162,154
Southeast	2,650	11,708	45,862	63,288	124,390
MidAtlantic	-	2,260	21,621	32,992	32,992
Southwest	-	-	9,919	12,067	12,067
Northwest	116	265	500	9,827	9,827
PJM	-	-	-	-	55,970
ERCOT	-	-	-	23,172	23,172
Total Output at Risk (GWh)	**4,740**	**19,933**	**151,581**	**275,766**	**420,573**
Gas-Fired Output (GWh)	**1,225,323**	**1,230,413**	**1,274,520**	**1,316,126**	**1,364,642**
vs. 2018 levels	*-17%*	*-16%*	*-13%*	*-10%*	*-7%*
Total Power Sector CO2 Emissions (mn metric tons)	**982**	**968**	**853**	**744**	**618**
vs. 2005 levels	*-59%*	*-60%*	*-65%*	*-69%*	*-74%*
vs. 2018 levels	*-44%*	*-45%*	*-52%*	*-58%*	*-65%*

Source: SNL Financial, EIA, Morgan Stanley Research estimates. Note: the "Variable Only or All-in Costs for Coal" refers to different approaches a utility may make in comparing coal-fired power plants to renewables economics — "Variable Only" indicates that only fuel plus variable costs are considered, while "All-in" includes fixed coal plant costs in the comparison. The carbon pricing scenario (Scenario 5) is based on a $40/ton carbon price. The capacity identified at risk excludes coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

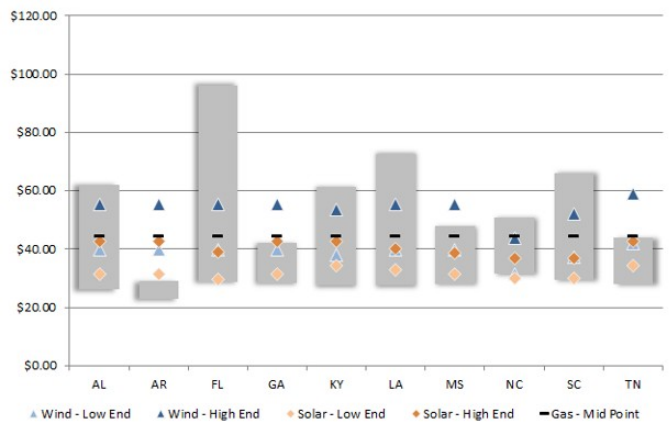
On a regional basis, we see the greatest opportunity in the Midwest and Southeast, given the economics of wind and solar resources in those regions, respectively, relative to the all-in costs of coal (fuel + variable O&M + fixed costs). We dive deep into each region in subsequent sections of this note.

Exhibit 17:
Economics of Coal (All-in Costs) in the Midwest by 2030



Source: SNL Financial, Morgan Stanley Research estimates

Exhibit 18:
Economics of Coal (All-in Costs) in the Southeast by 2030



Source: SNL Financial, Morgan Stanley Research estimates

We forecast $3-8b/year in potential savings in customer bills if the coal-fired electricity is replaced with the cheapest energy resource available in the region... Based on the average all-in cost of coal units at risk in each regulated region and the lowest available LCOEs of renewables, we calculated the implied savings to customers in Scenarios 3-4:

Exhibit 19:

Potential Customer Savings Under Scenario 3 (S.3.) and Scenario 4 (S.4.)

Savings	Avg. All-in Cost of at Risk Coal Units ($/MWh)	Cheapest Renewable Resource Available	LCOE Midpoint - Scenario 3 ($/MWh)	LCOE Bull Case - Scenario 4 ($/MWh)	Potential Savings - Scenario 3 ($mn)	Potential Savings - Scenario 4 ($mn)
Midwest	$37.41	Wind	$29.81	$24.55	$1,309	$4,046
Southeast	$50.87	Solar	$36.02	$31.64	$1,367	$2,445
MidAtlantic	$39.42	Wind	$37.64	$31.24	$90	$634
Southwest	$39.73	Solar	$32.60	$28.10	$158	$313
Northwest	$44.90	Wind	$32.85	$27.13	$16	$476
Total Savings ($mn)					**$2,941**	**$7,913**

Source: Morgan Stanley Research estimates

... at the same time, we identify a capex opportunity of $93-184b by replacing the current power output generated by the coal plants identified at risk with the cheapest available renewable energy resource in the region. This investment need translates into higher rate base growth and consequently EPS growth for many utilities, particularly those that have carbon-intensive power fleets and therefore will see a greater rate of change: AEP, SO, D, PPL, and DUK — *in our follow-on Part II report we intend to dive deep into these dynamics on a company-level basis.*

Exhibit 20:

Capex Opportunity in Regulated Regions — Scenarios 3-5

	Scenario 3	Scenario 4	Scenario 5
Midwest	$37,848	$60,825	$73,375
Southeast	$32,744	$39,023	$76,698
MidAtlantic	$15,171	$20,262	$20,262
Southwest	$7,539	$7,928	$7,928
Northwest	$341	$5,877	$5,877
Total Capex Opportunity ($mn)	**$93,644**	**$133,914**	**$184,139**

Source: Morgan Stanley Research estimates

For merchants, we found that the impacts for companies with exposure to ERCOT (VST and NRG) are more complex than investors appreciate and may not be as negative as expected given a longer-term mismatch of supply and demand in the summer time that will continue to put longer-term upward pressure in on-peak power prices. We expect this dynamic to continue as the on-peak forward power prices are not sufficient enough to drive new combined cycle gas plants, keeping on-peak power prices high. Despite the high availability of cheap renewables in the region that we forecast will put downward pressure on off-peak power prices and a potential dampening of upside to on-peak power prices in the medium-term from volumes of planned solar, we expect coal plants to remain economically viable in our base scenario. We expand on this dynamic in the Merchant section of this report.

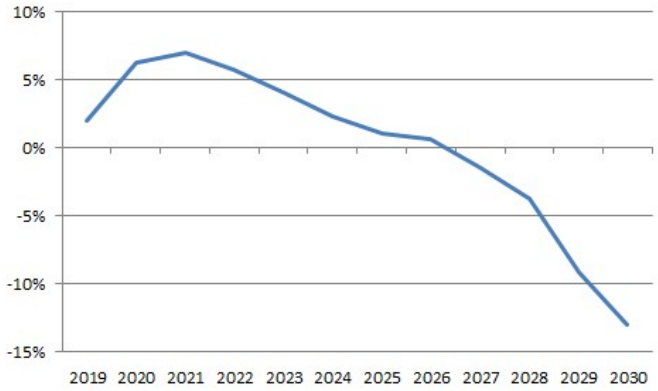
In PJM, beyond the ~3 GWs of coal capacity scheduled to retire in the next 2-3 years, we project no additional coal-fired plant retirements in the region absent a significant price on carbon. Other regions are left out (NY-ISO, ISO-NE, and CAISO) given they generate zero to almost zero coal-fired electricity.

We project that, from 2020 to 2030, natural gas demand to fuel power plants will initially increase but ultimately decline by ~13% in total. Despite this pressure in gas demand, in the very long term (beyond 2030), we forecast an important continued role for natural gas in the power sector, albeit with reduced overall gas demand, as these plants can help to "fill in the gaps" when renewable power output does not coincide with power demand. An example of this dynamic would be XEL, a large Midwestern utility that is rapidly moving toward wind and solar power. Xcel projects that natural gas will decline as a percentage of its power, from 29% in 2018 to 15% in 2030. Additionally, NextEra Energy has outlined the economics of renewables and natural gas driving the retirements of existing coal plants. We would expect Florida Power & Light to completely replace its coal power and partially replace other energy generation sources primarily with solar power by 2030. We expect the solar generation mix to grow by ~1,500bps and the gas generation mix to fall by ~1,000-1,500bps by 2030.

Overall, we forecast US coal-fired electricity to decline as a percentage of total US power generation from 27% in 2018 to just 8% in 2030 based on the total projected coal at risk and the forecasted additions of renewables and gas plants. Over the same time period we forecast wind and solar generation to increase from 9% of the mix to 30%, and gas to decline from 35% to 30%.

Exhibit 21:

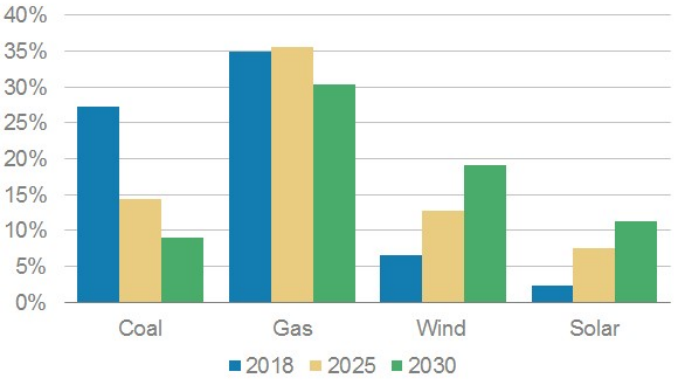
We project a cumulative 13% decline in power sector natural gas consumption by 2030



Source: Morgan Stanley Research estimates

Exhibit 22:

Changes in US Power Mix Generation Under Scenario 3

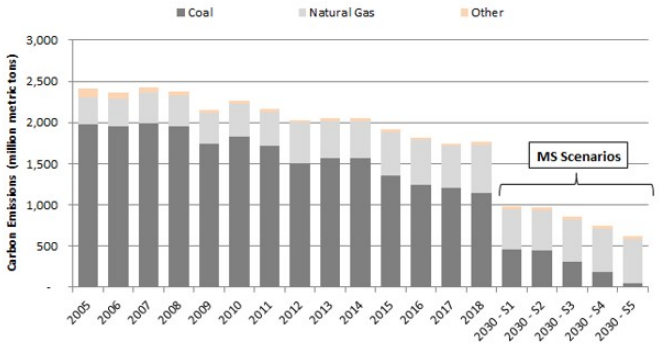


Source: Morgan Stanley Research estimates

Impacts on the Carbon Intensity of the US Power Sector

We forecast carbon emissions of the US power sector to decline by 65%+ by 2030 from 2005 levels. As mentioned in the previous section of this report, the amount of power produced by coal-fired power plants in the US in 2018 was ~40% lower than the amount of power produced by coal-fired power plants in 2005. This dynamic has been driven by declining natural gas prices and decreasing costs of renewable energy economics. During that same time period, carbon emissions of the US power sector declined by 27%. **We estimate in our base case (Scenario 3) an incremental decline in emissions of 37ppts by 2030, for a total reduction in emissions of 65% (vs. 2005 levels), or 74% based on Scenario 5, where we use a $40/tCO2e carbon price.**

Exhibit 23:
US Power Sector Carbon Emissions by Fuel



Source: EIA, Morgan Stanley Research estimates. Note: S1-S5 denotes our Scenarios 1-5.

Our estimates are driven by the retirement of coal capacity ranging from 2-192 GWs, depending on the scenario, or 33-223 GWs including units already scheduled for retirement. Using a 25% capacity factor in the year 2030 (as plants become less efficient over time) the total 33-223 GWs of coal capacity represent 73-491 TWh of coal-fired electricity that we model is replaced by a combination of renewables and natural gas (with the majority coming from renewables). Given a carbon intensity factor of 1 metric ton per MWh for coal and 0.4 for gas **we estimate total power sector emissions to decline between 65-74% by 2030 (vs. 2005) in what we view are the most likely scenario (Scenarios 3-5).**

Regulatory uncertainty in the US remains around if/when carbon pricing will be implemented and where the price will be set. In scenario 5 of our analysis, we assume a carbon price of $40/tCO2e. While this price is meaningfully above the existing regional carbon pricing schemes in the US (California $17/tCO2e / RGGI $5.20/tCO2e), we view this as a fair assumption in the context of what many economists believe is necessary to limit global warming to 2 degrees Celsius and achieve the goals of the Paris Agreement. We considered the following:

- The Climate Leadership Council's carbon dividend plan — which has been endorsed by energy companies, economists, and notable individuals including Janet Yellen, Ben Bernanke, Alan Greenspan, and Paul Volcker — contemplates a $40/tCO2e starting point with an annual increase of 5% plus inflation
- There are currently 6 carbon tax bills that have been introduced in the US legislature. While the initial pricing of those bills averages $29/tCO2e (ranging from $15 to $52/tCO2e), annual escalators (assuming the US does not meet certain emissions goals) imply an average price of $57/tCO2e by 2025 and $85/tCO2e by 2030
- Former World Bank chief economist Nicholas Stern thinks a carbon tax of $40-80/t by 2020 would be required to reach the goals of the Paris Agreement, which suggests that the majority of carbon pricing projects globally are currently too low
- The IMF has estimated that a global carbon tax of $75 per ton by 2030 would be necessary to limit the planet's warming to 2 degrees Celsius.

Stock Implications of a Price on Carbon

The biggest beneficiaries of a price on carbon would in our view be EXC and NEE, while the most negatively impacted would be NRG and VST. As we published recently in a note titled "US Public Policy: 2020 Vision: An Early Guide to the US Election," the implications of a price on carbon in the utilities sector depend on 1) whether a utility is regulated or diversified and 2) its generation fleet.

In the merchant space, we view EXC as the main beneficiary of a carbon tax given its large merchant nuclear fleet of 20GWs, which represents 61% of its total merchant capacity. For reference, applying a $10/MWh increase in power prices to EXC's non-carbon emitting generation in 2020 drives a $1.6bn (or 20%) increase in the company's 2020 margins — non-carbon emitting power plants, such as

those of EXC, benefit from higher margins given that a tax on carbon drives market clearing prices to increase, as the variable costs of running fossil fuel plants increase. On the contrary, companies with power fleets that are predominantly coal- and gas-fired, such as VST (94% of its capacity is coal- or gas-fired) and NRG (77%), would see their fossil-fuel plants at risk of becoming uneconomic. With a $40/tC02e carbon price, costs for coal plants would rise by ~$40/MWh and costs for gas plants would rise by ~$16/MWh given the different carbon intensities. Both companies would be impacted to varying degrees based on the pricing dynamics in the PJM and ERCOT markets, which we explore in the section **Regional Analysis: Merchants** .

Regulated utilities aren't impacted by a carbon tax in principle as these higher costs would be simply passed on to customers. That said, increased electricity rates could create political and regulatory pressure on the utilities to retire expensive plants. While the fuel cost savings achieved from retiring a fossil-fuel plant and replacing it with renewable energy resources can be large enough to offset the costs of retiring early a power plant (accelerated depreciation is also a cost that is passed on to customers), depending on the state and the regulatory environment, utilities could potentially face the risk of ending with a stranded asset on their books (an asset on which they cannot recover their investment). Ultimately, the impact depends on the companies' portfolio mix and jurisdiction.

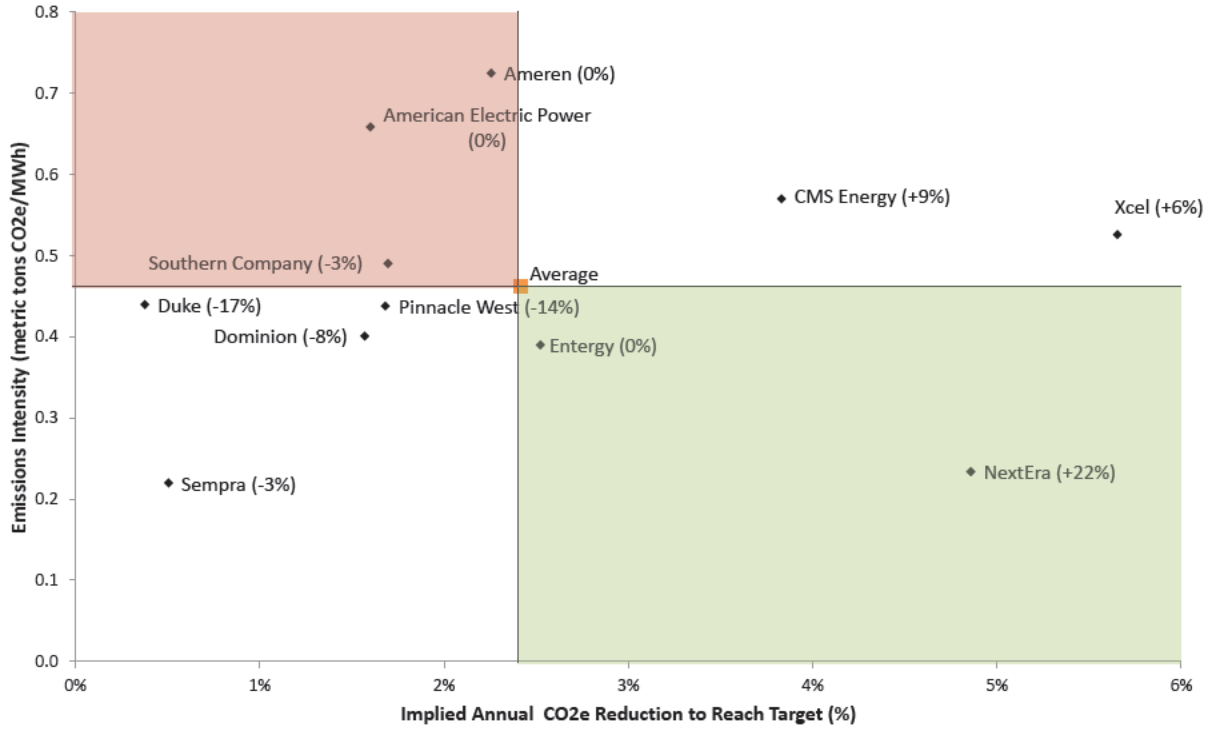
Case Studies — The Shift Away from Coal and Toward Renewable Energy: A Key Growth Opportunity for Utilities

We believe the market does not fully appreciate the long-term growth opportunity for utilities to pursue the shutdown of coal-fired generation and the replacement of this generation with renewable energy.

We see the greatest opportunity in regulated utilities that have historically targeted less rapid movements away from coal power: AEP, SO, D, PPL, and DUK. The fastest growing US utilities are those that are moving most aggressively toward clean energy — including NEE, XEL, AEE, CMS, and SRE, which trade at an average premium to the group of 9% on a 2021 P/E basis. What drives this growth-decarbonization relationship? When renewables become sufficiently cheap, a utility can shut down a coal-fired power plant, invest in new renewables (increasing rate base growth), and recover the remaining rate base of the retired coal plant (which is typically low) — and the result is a net lower power bill for customers or rate headroom for other growth initiatives. **We believe this "virtuous cycle" will be a major theme in the utility sector over the next ~20 years.**

Given economics of renewables relative to coal, particularly in the Midwest and Southeast regions, we see a potential "second wave" of the transition to renewable energy, with utilities such as SO, D, PPL, DUK and AEP, which currently trade at a 8% average discount to the group on a 2021 P/E basis, as the leading contenders to pursue this model. NextEra's acquisition of Gulf Power, discussed below, gives an indication of how beneficial this "virtuous cycle" can be for investors.

Exhibit 24:
Emissions Intensity vs. Implied Annual Emissions Reduction & Premium/Discount to Peers on 2021 Valuation Multiples



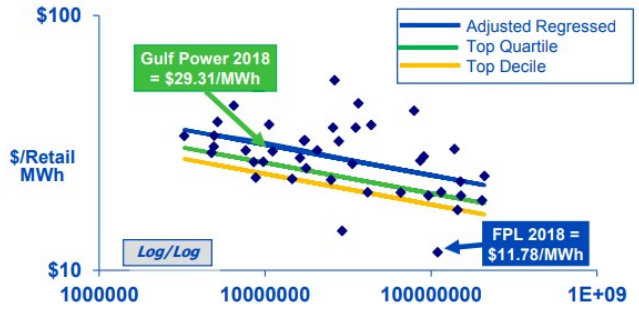
Source: Company Data, Morgan Stanley Research, Thomson Reuters Pricing as of 11.29.2019. Annual CO2e reduction to reach target calculated as the implied annual reduction in emissions/intensity needed to reach publicly stated CO2 target.

Case Study #1: NextEra's Acquisition of Gulf Power

NextEra's (NEE) acquisition of Gulf Power, a Florida utility, from Southern Company (SO) gives an indication of how beneficial the "virtuous cycle" can be for investors.

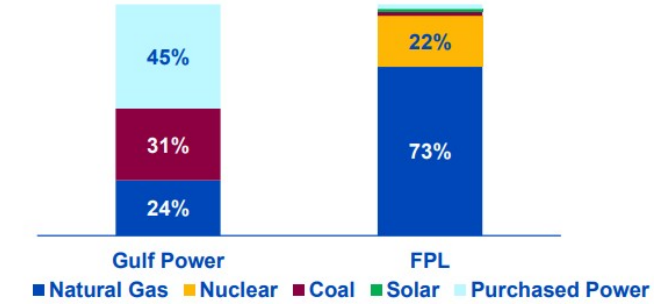
Gulf Power's cost profile, and carbon intensity, is much higher than NextEra's Florida utility (FP&L). Below are a few key data points on the relative comparison between these two utilities:

Exhibit 25:
Operational Cost Effectiveness of Southeastern Utilities



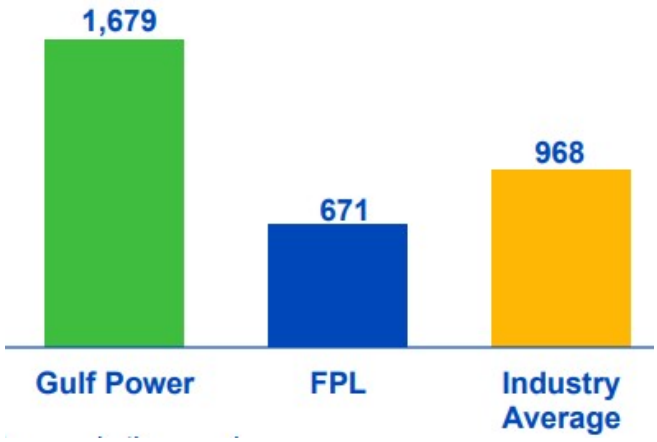
Source: Company data.

Exhibit 26:
Gulf Power vs. FP&L Generation Mix



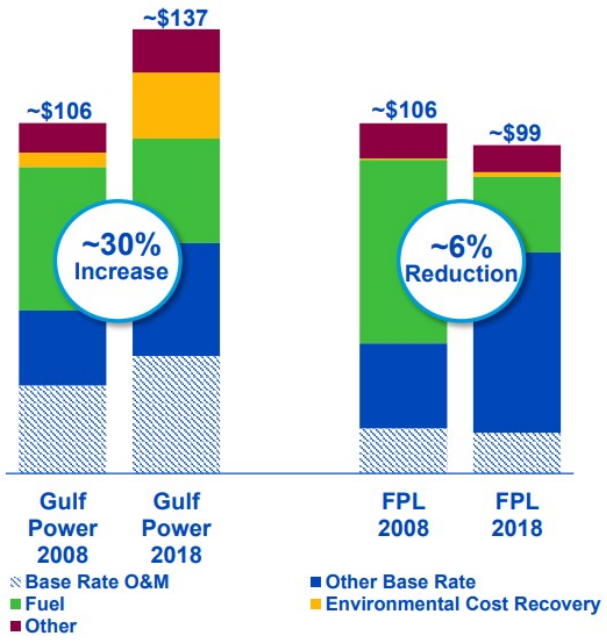
Source: Company data.

Exhibit 27:
CO2 Emissions Rate Comparison (Lbs/MWh)



Source: Company data.

Exhibit 28:
2008 vs. 2018 Comparison of a 1,000-kWh Residential Bill for Gulf Power and FP&L



Source: Company data.

By reducing Gulf Power's costs, deploying renewables and shutting down expensive coal-fired power plants, NextEra is likely to improve returns significantly for shareholders, while improving the customer value proposition.

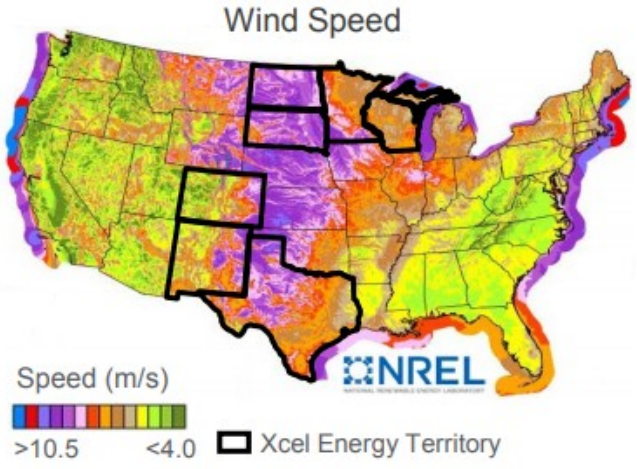
Key takeaways:

1. **NextEra is targeting a tripling of Gulf Power's net income growth,** moving to a 16% CAGR through 2022 for this utility;
2. **Gulf Power's carbon emissions intensity will fall by ~40%** in 2018-21;
3. **Gulf Power's residential customer bills will drop by ~9% by 2021,** with a further ~20% reduction by the mid-2020s.

Case Study #2: Xcel's Shift to Renewable Energy

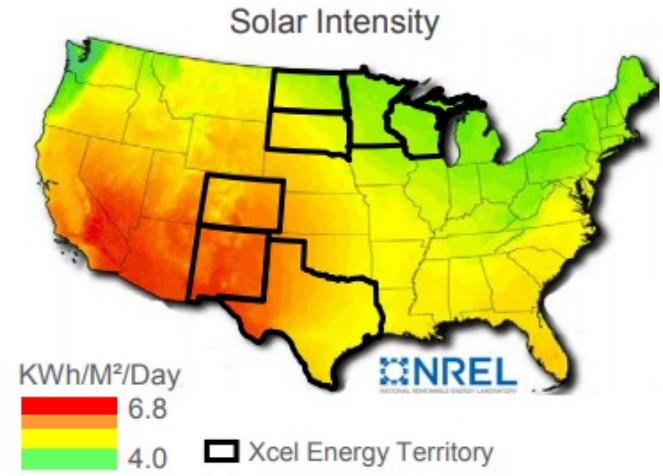
Xcel is one of the leaders with respect to decarbonization, with a goal that is ~2x the level set forth in the Paris climate agreement. Xcel's service territories are fortunate to have very favorable wind and solar economics, as shown in **Exhibit 29** and **Exhibit 30**:

Exhibit 29:
XEL's territory offers high capacity factors for wind...



Source: Company data. National Renewable Energy Laboratory.

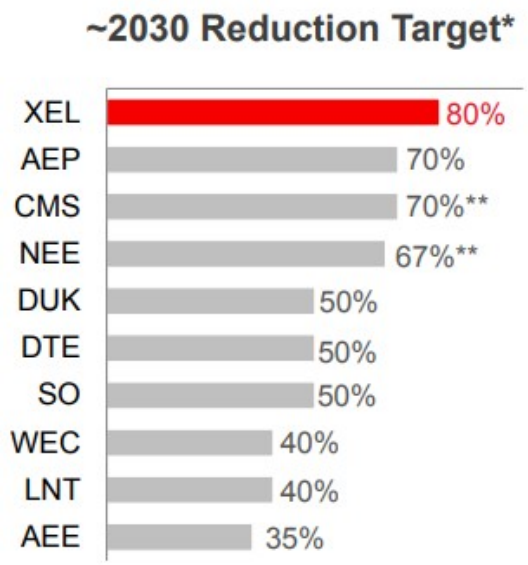
Exhibit 30:
...and for solar, enabling greater efficiency and lower renewable costs



Source: Company data. National Renewable Energy Laboratory.

As a result of pursuing a well-regarded "Steel for Fuel" program, in which new wind farms (the "Steel") replace its coal-fired power plants (that have high fuel costs), Xcel's EPS growth rate has exceeded the peer average. We project Xcel will increase its EPS by ~7% annually through 2022, above the peer average of 5.5% — and this premium growth is in our view largely due to the above average rate base growth opportunity provided by wind power plant development. The result of this movement to wind power on the company's carbon emissions profile is significant:

Exhibit 31:
XEL's 2030 carbon reduction goals exceed peer goals...



Source: Company data. * As of October 2019; all baselines are 2005 except for AEP (2000) and Southern (2007). ** CMS is 70% by 2032 and 90% with no coal by 2040; NEE is 67% by 2025.

Exhibit 32:
...and XEL is the first US Utility to commit to 100% carbon free

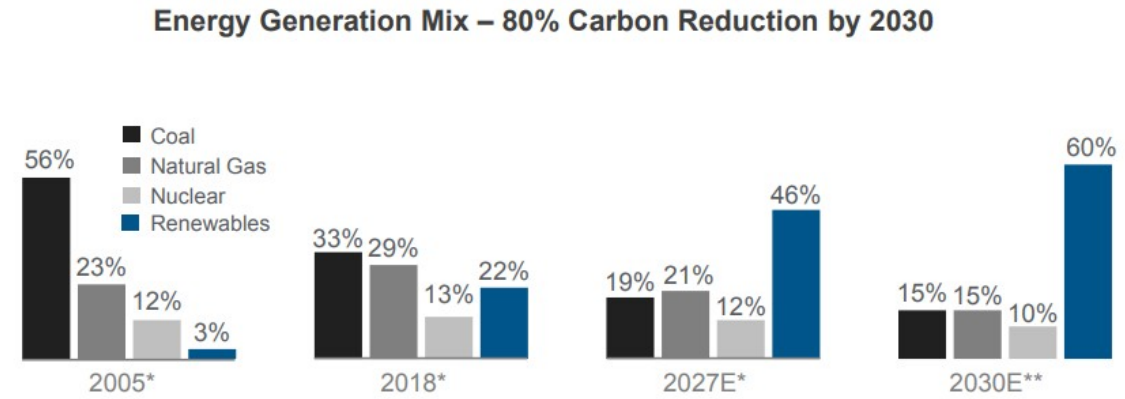


Source: Company data. * As of October 2019; all baselines are 2005 except for AEP (2000) and Southern (2007). ** CMS is 70% by 2032 and 90% with no coal by 2040; NEE is 67% by 2025.

Over time, Xcel's usage of fossil fuels will decline significantly. Exhibit 33 shows the past, present, and future generation mix for Xcel. Note that gas-fired generation still plays a role in Xcel's energy mix (providing controllable power output to ensure grid reliability, even during extended periods in which renewables output is limited):

Exhibit 33:

XEL is aggressively transitioning away from coal and toward renewables



Source: Company Data. * Remaining includes hydro, biomass and other sources; future-year estimates dependent on various factors. ** Potential scenarios that achieve carbon reduction goal

Case Study #3: The Daniel Coal-Fired Plant in Mississippi

Following NextEra's purchase of Gulf Power, which has utility operations in Mississippi, NextEra made the decision to pursue the retirement of its ownership stake in a coal-fired power plant (called the Daniel Plant) co-owned with a Southern Company subsidiary known as Mississippi Power. In Mississippi, between 2008 and 2018, natural gas-fired power output moved from 43% of output to 78%, while coal-fired output moved from 35% to 8% during that same period. In a recent filing with FERC, the co-owners of Plant Daniel, a 1 gigawatt, 2-unit plant, *"have committed to seek a restructuring of their 50% undivided ownership interests in Plant Daniel such that each of them would, after the restructuring, own 100% of a generating unit."* We calculate that the all-in cash cost to operate Plant Daniel is somewhat above $42/MWh, well above the cost of large-scale solar, which we forecast would be in the low-to high-$30s/MWh level.

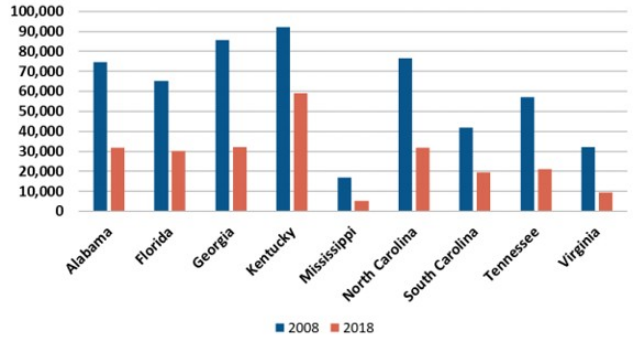
Plant Daniel's capacity factor has been in the low- to mid-20% level, which we view as indicative of a plant facing economic challenges — coal-fired power plants should in general operate at least during most on-peak hours (implying a ~45% capacity factor) in order to have a better chance of covering their fixed costs. **We believe the regulatory deliberations regarding this plant will be indicative of the future economic prospects for many coal-fired power plants in the US.**

In an excellent study of coal-fired generation entitled "Coal-Fired Power Generation in Freefall Across Southeast US" the authors (from the Institute for Energy Economics and Financial Analysis, IEEFA) make several interesting observations about coal-fired power in the Southeast (one of the more coal-heavy regions in the US):

1. Coal-fired power output has fallen significantly over the past 10 years throughout the region (see **Exhibit 34**).
2. "The future for coal in the region is one of continuing decline, if not complete obsolescence."
3. Solar growth in the region could be significant. Recent data points include: 1) the Georgia utility regulator's order that Georgia Power install 2,260 MW of new solar by 2024, 2) three Florida utilities' plans to install >11 GW of solar power over the next 10 years, and 3) a South Carolina utility's plans to add 1 GW of solar capacity by 2024.

Exhibit 34:

Coal-Fired Generation by State (MWh)



Source: Institute for Energy Economics and Financial Analysis, IEEFA

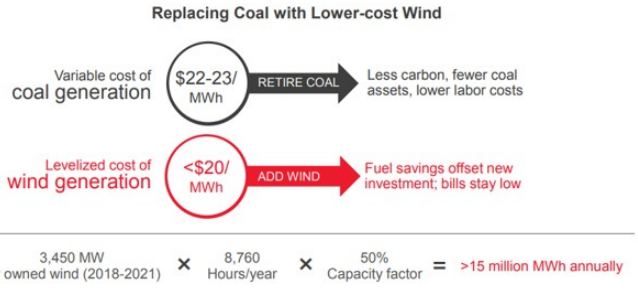
Assessing How Utilities Will Compare Coal-Fired Generation Against Renewables

There is an underappreciated, important nuance regarding how utilities across the US will approach the decision to potentially retire coal-fired generation and replace some or all of this output with renewables. The key issue is how utilities assess the benefits of the "firm capacity" associated with coal-fired power relative to the "intermittent" nature of renewable energy. We will provide a few contrasting examples to better explain different approaches that utilities might take.

The "Coal Variable Cost" Approach: Xcel Energy

As XEL makes the decision to retire coal-fired plants in favor of wind and solar power, the company has compared just the variable costs of its coal-fired plants (excluding fixed cash costs) relative to the all-in costs of new renewables projects. **Exhibit 35** shows how Xcel makes this determination:

Exhibit 35:
Xcel's "Steel for Fuel" strategy hinges on the fact the wind LCOE's now undercut the variable cost of coal generation in several jurisdictions



Source: Company Data

The argument to exclude a coal plant's fixed costs in the retirement assessment is driven by the view that, because coal plants are "dispatchable" (they can produce power when needed, and renewables assets are "intermittent" (meaning they produce power when the wind blows or the sun shines), the fixed costs of the coal plant represent a benefit (controllability) that a renewable asset does not possess. That said, even when only considering a portion of the total costs of running their coal plants, the company is at the forefront of the transition to clean energy.

Xcel's Upper Midwest Integrated Resource Plan

In July 2019, Xcel published its Upper Midwest Integrated Resource Plan, which can be found here. A few key takeaways from this plan that are most pertinent in the assessment of coal plant economics relative to renewables:

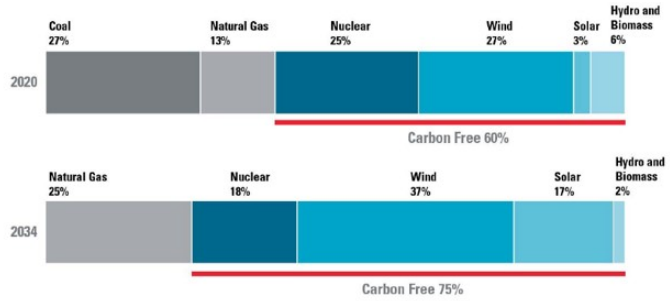
1. The plan would result in the elimination of all coal-fired generation in the portfolio by 2030, "a decade earlier than previously anticipated."

2. In considering the grid reliability impacts from a major shift toward renewables, Xcel highlighted the need for flexible, natural gas-fired generation (emphasis added): *"The addition of several gigawatts of renewable resources requires that we consider not only our traditional summer peak, but also whether we have sufficient dispatchable resources to meet other peaks, including in winter when solar energy is typically unavailable and wind resources may not be available for long periods of time. Our Preferred Plan addresses these reliability issues in three ways. First, the extension of Monticello [a nuclear power plant] by an additional 10 years and the continued operation of Prairie Island [another nuclear power plant] will anchor our grid in around-the-clock, carbon-free energy. Second, we are proposing to take ownership of the Mankato Energy Center and build a new CC [natural gas-fired] plant at our Sherco site in 2026. These dispatchable resources will be critical as we retire 2,400 MW of coal-fired baseload and transition to a system that is nearly 60 percent renewable and intermittent generation. Finally, we propose several firm dispatchable, load-supporting resources – but defer these additions until the latter part of the decade, in anticipation of technological advancements that will improve the functionality and drive down the cost of resources, like storage, that can take the place of traditional gas peaking units.... **The capacity value of renewables combines with our cost-effective gas and nuclear generation to deliver safe and reliable service that will withstand the summer and winter peaks of the Upper Midwest....** Together, our [Mankato gas-fired plant] acquisition and constructing the Sherco CC will not materially impact the amount of gas generation on our system. As already discussed, **[the Mankato gas-fired plant] is already an existing resource on our system, and the Sherco CC [a gas-fired plant] will primarily offset the retirement of other gas generation on our system, including the Cottage Grove facility (approximately 250***

MW in 2027) and Black Dog 5 (approximately 300 MW in 2032). This additional gas generation is not only reasonable, but an operational necessity in light of the much larger coal retirements planned — and the large amounts of variable renewable additions we anticipate in the same period."

3. The proposed change to Xcel's Upper Midwest energy mix is significant, as shown in **Exhibit 36**:

Exhibit 36:
Xcel's Preferred Plan Energy Mix Through 2034



Source: Company data.

4. Xcel spoke to the potential limits of renewable penetration, after which grid reliability issues become more significant, and potentially unaddressable in a cost-effective manner absent further technology improvements over time: *"In total, our Preferred Plan envisions a system that is approximately 60 percent renewable energy — a level that puts us among those leading the nation. And, while we are confident in our ability to deliver on our reliability commitment at this high level of renewable penetration, we are somewhat cautious at the same time about going much beyond those levels in light of our own experience, as well as recent industry studies regarding the complexity and complications of an exceedingly high renewable grid."*

The "All-In Cost of Coal" Approach

An alternative approach would be to include all coal costs, both variable and fixed, when making a determination as to whether to shut down coal-fired power plants and replace some or all of the lost power with renewable energy. This approach, which we believe will be favored by many constituents, is driven by several arguments:

1. The fixed costs of a coal-fired plant may be in excess of the value of being able to dispatch a coal-fired power plant. For example, in the competitive, Mid-Atlantic PJM power market, the price of capacity that has been set by competitive bidding is well below the fixed costs of some coal-fired generation — which, in turn, is driving the owners of many coal-fired plants in PJM to retire these plants.

2. Environmental advocates may point to the "externalities" created by the emissions (carbon dioxide, NOx and SOx) from coal-fired plants, which may not be fully reflected in the economic dispatch decisions of a coal-fired plant owner.

3. Renewable energy has some magnitude of "capacity value," which can be determined by comparing the overlap between renewable power output and customer power demand. In PJM, solar power is assigned a capacity value equal to [35%] of a dispatchable fossil fuel power plant, while wind receives [15%] capacity value.

4. When renewables are combined with energy storage, the capacity value may increase significantly. Innovative renewables developers such as NextEra (NEE) and AES have developed combinations of wind, solar and energy storage, with the resulting product being "semi-firm" — and this combined product could potentially have significantly greater capacity value. That said, NextEra projects that the cost of storage could add ~$5/MWh to the cost of a renewables project that has been combined with energy storage — so this "firming" comes with a cost.

5. Up to certain levels of renewables penetration, the practical grid reliability issues (caused by renewables intermittency) may be somewhat modest. Numerous studies have been conducted on the levels of renewables penetration at which additional technologies are required to ensure grid reliability, and to ensure that renewable energy is delivered when customers need the power. California, Hawaii and Xcel Energy's Upper Midwest Integrated Resource Plan represent useful case studies.

Regional Analysis: Regulated States

Midwest

We see the greatest coal at risk / opportunity in the Midwest region given favorable wind economics, with wind LCOEs as low as $20/MWh (post PTC step down) comparing to the current all-in cost of coal $30/MWh on average, or a range of $14-73/MWh. **We forecast 34 GWs of coal capacity (45% of total) to be at risk by 2030 under our base scenario, amount that grows to 74 GWs in Scenario 5, which would represent 100% of the region's coal capacity**. Regulated utilities under our coverage with exposure to the Midwest include AEE, AEP, CNP, CMS, DUK, and XEL.

Exhibit 37:

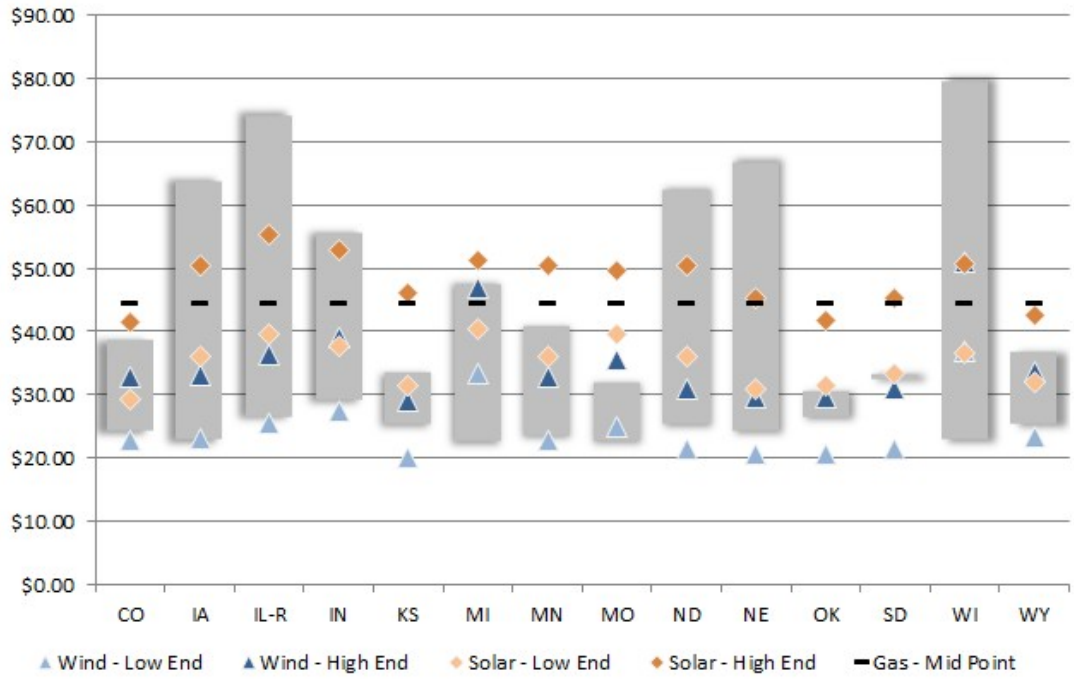
Midwest: Coal Capacity at Risk by 2030 Under Various Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Renewables LCOE Scenario	*Bear*	*Midpoint*	*Midpoint*	*Bull*	*Bull*
Variable Only or All-in Costs for Coal?	*Variable Only*	*Variable Only*	*All-in*	*All-in*	*All-in*
Carbon Pricing?	*No*	*No*	*No*	*No*	*Yes, $40/tCO2e*
Midwest					
Coal Capacity at Risk (GWs)	0.9	2.6	33.6	61.4	74.0
% of total Capacity in the Region	1%	4%	45%	83%	100%

Source: SNL Financial, EIA, Morgan Stanley Research estimates. Note: The capacity identified at risk excludes coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

Exhibit 38:

Midwest: Coal Economics by 2030 Under Scenario 3



Source: SNL Financial EIA, Morgan Stanley Research estimates. Note: Excluding coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

Southeast

The Southeast is the second region by "transition" potential, driven primarily by favorable solar economics, with solar LCOEs as low as $30/MWh (post ITC step down) comparing to the current all-in cost of coal $41/MWh on average, or a range of $16 to over $100/MWh. **We forecast 21 GWs of coal capacity (37% of total) to be at risk by 2030 under our base scenario, an amount that grows to 57 GWs in Scenario 5, which would represent 100% of the region's coal capacity.** Regulated utilities under our coverage serving the region include D, DUK, NEE, PPL, and SO.

Exhibit 39:

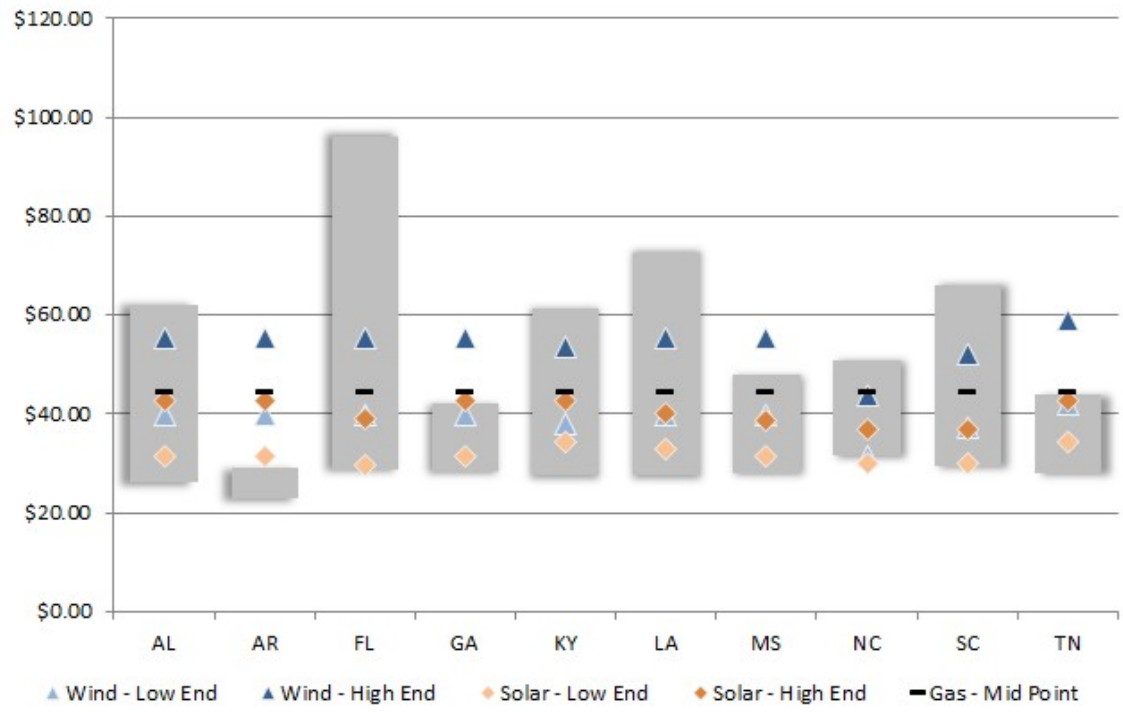
Southeast: Coal Capacity at Risk by 2030 Under Various Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Renewables LCOE Scenario	*Bear*	*Midpoint*	*Midpoint*	*Bull*	*Bull*
Variable Only or All-in Costs for Coal?	*Variable Only*	*Variable Only*	*All-in*	*All-in*	*All-in*
Carbon Pricing?	*No*	*No*	*No*	*No*	*Yes, $40/tCO2e*
Southeast					
Coal Capacity at Risk (GWs)	1.2	5.3	20.9	28.9	56.8
% of total Capacity in the Region	2%	9%	37%	51%	100%

Source: SNL Financial, EIA, Morgan Stanley Research estimates. Note: The capacity identified at risk excludes coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

Exhibit 40:

Southeast: Coal Economics by 2030 Under Scenario 3



Source: SNL Financial EIA, Morgan Stanley Research estimates. Note: Excluding coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

MidAtlantic

We see all coal capacity in the MidAtlantic as being uneconomic by 2028, relative to our bull renewables LCOEs, even without a carbon tax. The economics of renewables in the MidAtlantic region vary widely by state, with wind resources being the cheapest source in OH and WV and solar resources in VA. Renewables LCOEs in the region can be as cheap as $28-30/MWh (post tax credits step down), which compares to the current all-in cost of coal of $35/MWh on average, or a range of $21-56/MWh. This dynamic worsens over time (for coal resources), as we model technology improvements in renewables to offset fully inflationary pressure, while coal units do see increased costs driven by inflation.

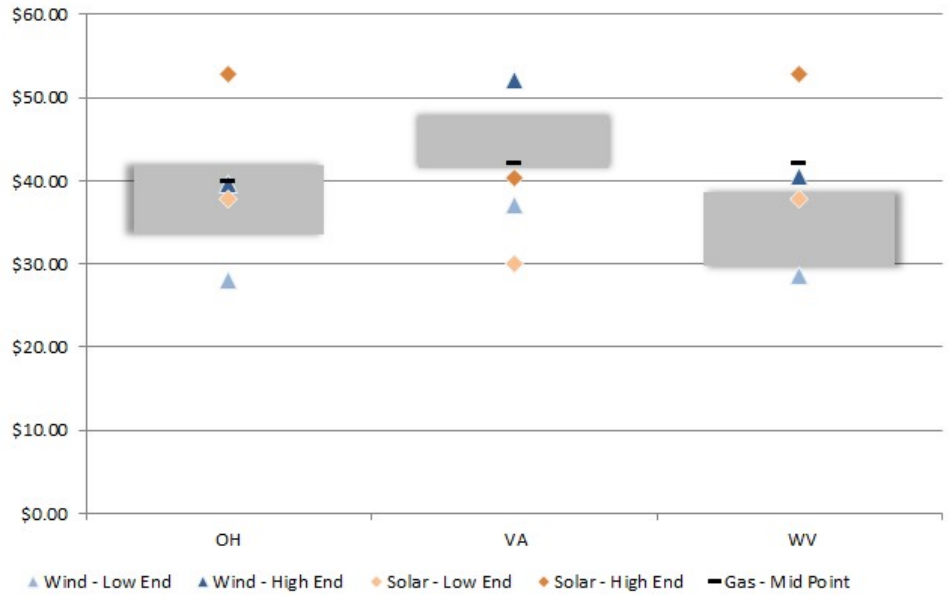
In our base case, Scenario 3, we forecast 10 GWs of coal capacity (66% of total) to be at risk by 2030. Scenario 4, which uses bull LCOEs for renewables instead of the midpoint, would drive all coal to be at risk by 2028. A carbon tax simply accelerates this transition. Regulated utilities under our coverage serving the region include AEP, D, and FE.

Exhibit 41:
MidAtlantic: Coal Capacity at Risk by 2030 Under Various Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Renewables LCOE Scenario	*Bear*	*Midpoint*	*Midpoint*	*Bull*	*Bull*
Variable Only or All-in Costs for Coal?	*Variable Only*	*Variable Only*	*All-in*	*All-in*	*All-in*
Carbon Pricing?	*No*	*No*	*No*	*No*	*Yes, $40/tCO2e*
MidAtlantic					
Coal Capacity at Risk (GWs)	-	1.0	9.9	15.1	15.1
% of total Capacity in the Region	0%	7%	66%	100%	100%

Source: SNL Financial, EIA, Morgan Stanley Research estimates. Note: The capacity identified at risk excludes coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

Exhibit 42:
MidAtlantic: Coal Economics by 2030 Under Scenario 3



Source: SNL Financial EIA, Morgan Stanley Research estimates. Note: Excluding coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

Southwest

Similar to the MidAtlantic, we see all coal capacity in the Southwest as being uneconomic, relative to our bull renewables LCOEs, even without a carbon tax. Solar LCOEs in the region LCOEs can be as cheap as $28/MWh (post tax credits step-down), which compares to the current all-in cost of coal of $37/MWh on average, or a range of $30-47/MWh. **We forecast 4.5 GWs of coal capacity (82% of total) to be at risk by 2030 under our base scenario, amount that grows to 5.5 GWs in Scenario 4, 100% of the region's coal capacity.** PNW is the only regulated utility under our coverage serving the region, which we believe may take more aggressive action to deploy solar power and energy storage, and will lay this out in their April 2020 Integrated Resource Plan (IRP).

Exhibit 43:

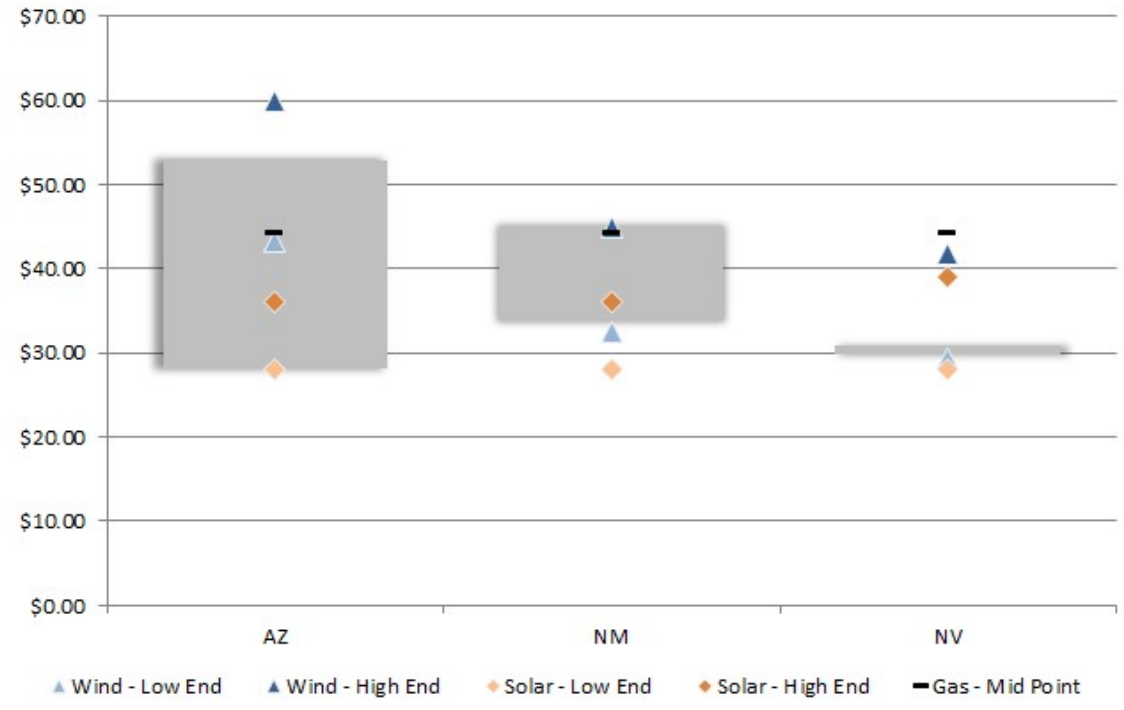
Southwest: Coal Capacity at Risk by 2030 Under Various Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Renewables LCOE Scenario	*Bear*	*Midpoint*	*Midpoint*	*Bull*	*Bull*
Variable Only or All-in Costs for Coal?	*Variable Only*	*Variable Only*	*All-in*	*All-in*	*All-in*
Carbon Pricing?	*No*	*No*	*No*	*No*	*Yes, $40/tCO2e*
Southwest					
Coal Capacity at Risk (GWs)	-	-	4.5	5.5	5.5
% of total Capacity in the Region	0%	0%	82%	100%	100%

Source: SNL Financial, EIA, Morgan Stanley Research estimates. Note: The capacity identified at risk excludes coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

Exhibit 44:

Soutwest: Coal Economics by 2030 Unedr Scenario 3



Source: SNL Financial, EIA, Morgan Stanley Research estimates

Northwest

We found only a relatively small amount of coal (228 MWs) to be uneconomic in our base scenario, while all the existing coal output is deemed at risk when compared to bull LCOEs in the region (wind resources for MT and solar for UT). As with the MidAtlantic and Southwest, a carbon tax simply accelerates this transition.

Exhibit 45:

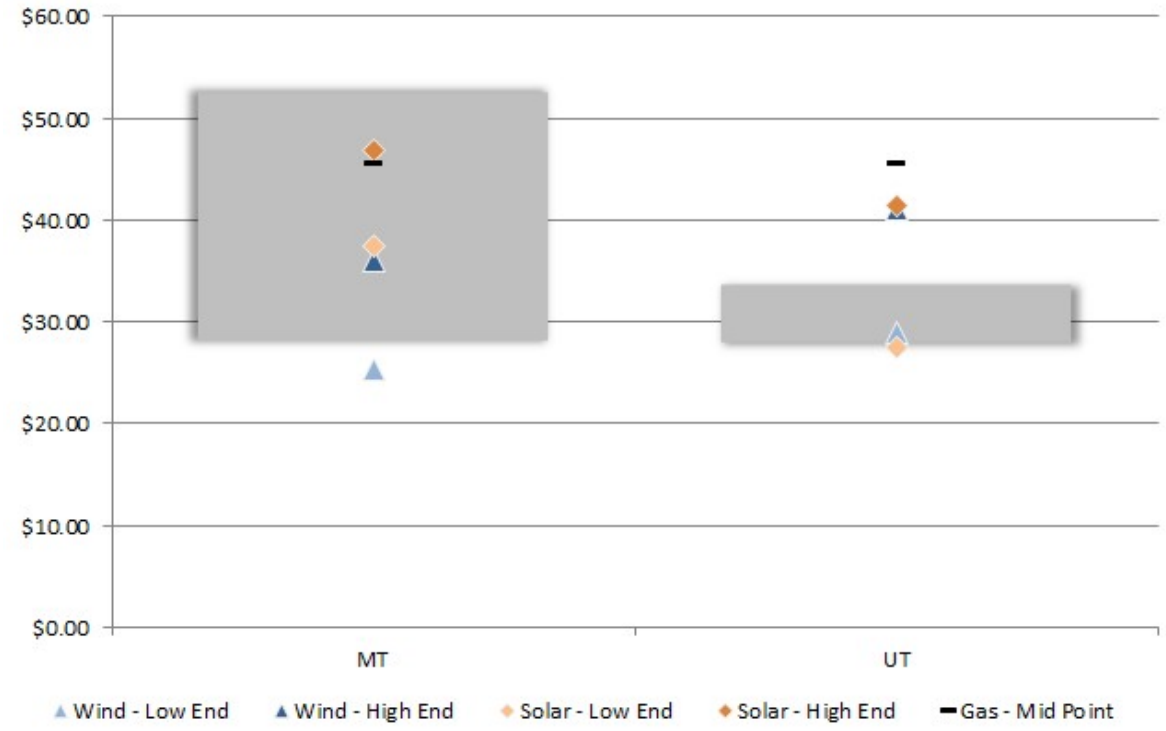
Northwest: Coal Capacity at Risk by 2030 Under Various Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Renewables LCOE Scenario	*Bear*	*Midpoint*	*Midpoint*	*Bull*	*Bull*
Variable Only or All-in Costs for Coal?	*Variable Only*	*Variable Only*	*All-in*	*All-in*	*All-in*
Carbon Pricing?	*No*	*No*	*No*	*No*	*Yes, $40/tCO2e*
Northwest					
Coal Capacity at Risk (GWs)	0.1	0.1	0.2	4.5	4.5
% of total Capacity in the Region	1%	3%	5%	100%	100%

Source: SNL Financial, EIA, Morgan Stanley Research estimates. Note: The capacity identified at risk excludes coal units that are already scheduled to retire, coal units smaller than 50MWs, and coal units with a capacity factor in 2018 under 10%.

Exhibit 46:

Northwest: Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, EIA, Morgan Stanley Research estimates

Regional Analysis: Merchants

ERCOT (Texas)

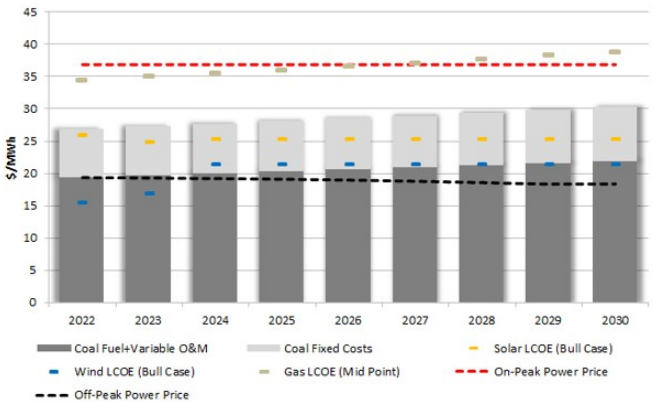
The all-in costs of large coal plants in ERCOT surpass renewables' LCOEs on average, but high peak demand and high costs for gas new builds will likely keep large coal units as part of ERCOT's generation mix for the foreseeable future absent a price on carbon. In Texas, we project demand will grow at a robust rate (versus a modest decline across the US on average), at ~1.5-2.0% per year on average. With all-in costs (fuel + variable O&M + fixed costs, including a return on and of capital) for solar and wind projects in the $21-25/MWh range for our bull case in 2024, comparing to merchant forward power prices in 2022 of $36-40/MWh on-peak and $19-21/MWh off-peak, we expect the majority of power demand growth in ERCOT to be met with renewables. Nonetheless, we think it will be difficult for the growth in peak summer demand of ~75 GWs to be fully met with renewable energy resources over time. There are ~25GWs of installed renewable energy capacity; ~23GW is wind and ~2GW is solar. Wind contributes 25% of nameplate capacity to peak, while solar contributes 76% to peak (renewables, therefore, contributing ~10% to peak capacity currently). Load growth in the market implies ~2 GW of new solar needed just to meet annual increases in peak load, and the market is currently well below the target reserve margin so even more renewables would be needed to catch up to this level. This, coupled with ~$40/mwh on-peak prices needed to incentivize new gas plant construction, would cause large coal plants, most of them owned by VST (5 GWs) and NRG Energy (4 GWs), to remain in operations through 2030 in our view.

Absent a price on carbon, we see coal plants running in the on-peak hours mostly, but remaining able to cover their cash operating costs (on average) given high on-peak prices. The average cost to dispatch a coal plant (i.e. fuel + variable O&M costs) in ERCOT starts at $19/MWh in 2022 and rises to $22/MWh in 2030. Given that these costs are above our estimate of off-peak prices (see **Exhibit 47**), we expect to see coal plants running primarily during on-peak times, driving capacity factors to fall from 60-70% in recent years to 45%. Given scarcity pricing in ERCOT — where supply becomes tight as demand ramps up close to supply limits in summer months, increasing power prices significantly — even when coal plants run only in on-peak times, they remain economic on our math as on-peak prices are high enough to cover the plants' fixed costs, which are not included in the dispatch cost at which plants bid into an energy market.

We do see risk to coal in stronger renewables scenarios: On our math all coal plants could be at risk of shutdown in a high renewables deployment scenario (Scenario 4). We maintain our view that it will be challenging to meet supply needs from load growth with just renewables, and many coal plants are likely to remain in operation given pricing dynamics in ERCOT. However, high renewables penetration is looking increasingly possible given recent datapoints. The recently released ERCOT December 2019 Capacity, Demand and Reserve (CDR) report showed higher renewables deployment estimates than the previous report published in May 2019 (see note here). Our analysis for planned solar in 2020 indicates that ~2.5GW is under construction or in development with a signed PPA: 1.2GW is under construction, 0.4GW is in advanced development with a signed PPA, and 0.9GW is in early development with a signed PPA. Our analysis for planned wind in 2020 indicates that ~3.1GW is under construction or in development with a signed PPA: ~1.6GW is under construction, ~0.3GW is in advanced development with a signed PPA, and ~1.2GW is in early development with a signed PPA. Vistra has modeled an aggressive deployment scenario that lays out 22GW of solar deployment, 22 GW of wind deployment, and 6GW of battery storage deployment by 2030. For context, in this scenario, ~28GWs of renewables + storage contributes to peak capacity assuming that 76% of solar nameplate capacity contributes to peak, 25% of wind contributes to peak, and 100% of battery storage contributes to peak. This compares to peak load growth of 13GW by 2030 as estimated from ERCOT's latest CDR report, implying that reserve margins could rise. This suggests that in a more aggressive renewables scenario a looser market would pressure pricing and cause all of the remaining coal plants to be at risk.

Exhibit 47:

ERCOT — Large Coal Units Avg. Costs vs. Renewables & Gas LCOEs



Source: SNL Financial, Morgan Stanley Research estimates

We based our offpeak prices on a dispatch model, while setting the onpeak prices off our view on the longer-tem mismatch in supply-demand in ERCOT. The dispatch model aggregates demand and supply data to calculate marginal generating unit cost. Offpeak pricing is derived based off the historical clearing prices at varying demand levels. The offpeak price in 2022 is set by the forward curve, but the years after reflect a YoY change in offpeak prices calculated from the dispatch model. The on-peak price was set at the 2022 forward curve to reflect a longer-term mismatch between 1) the volume of renewables available during peak demand periods and 2) increases in power demand due to rapid economic growth in Texas. Key inputs to the dispatch model (please ask us for a copy), include:

- Demand data (from ISO/RTO website)
- Supply data (from SNL and ISO/RTO website)
- New build
- Retirements
- Fuel costs ($/MWh)
- Non-fuel variable operating costs ($/MWh)

Stock Implications

While investors view NRG and VST as having margins negatively exposed to the growth in cheap renewables in ERCOT, the reality is more complex and nuanced. It may be that these merchant companies do not see any negative margin pressure from renewables for a very long period of time, due to a number of related dynamics:

A. The growth in peak demand (at 1.5-2.0 GW/year) is not being fully met by the annual increase in solar power capacity, which has been in the 0.1-0.9 GW range per year over the past 5 years. Given this mismatch between peak supply and demand, we could actually see power prices rise, given that there will be more scarcity events in which the supply-demand balance is very tight. In the ERCOT market, when we see very tight supply-demand days, the power price can increase significantly, all the way to a very high cap ($9,000 per MWh, orders of magnitude higher than the average forward power price of ~$30/MWh).

B. It can be challenging for new renewable projects to secure long-term power sales agreement — and these hedges are critical to securing financing. In ERCOT, there are relatively few counterparties that would be interested in purchasing the power from renewable projects, due to the deregulated market structure in this market. This scarcity of hedges will in our view continue to reduce the amount of renewables projects that are built in the state, even though forward power prices would theoretically indicate that renewables projects could earn above their required rate of return.

C. Vistra and NRG have very large retail energy businesses, which provides an effective hedge for the output of these companies' power plants — this serves to provide a stable, profitable market for the companies' power output, and reduces (but does not eliminate) the pressure to shut down power plants. NRG's retail business is able to sell a larger percentage of power from the company's plants relative to Vistra, so Vistra would therefore be more exposed to any power price downturns brought about by the continued growth in renewable energy, to the extent we see such a downturn.

Implications of a Price on Carbon

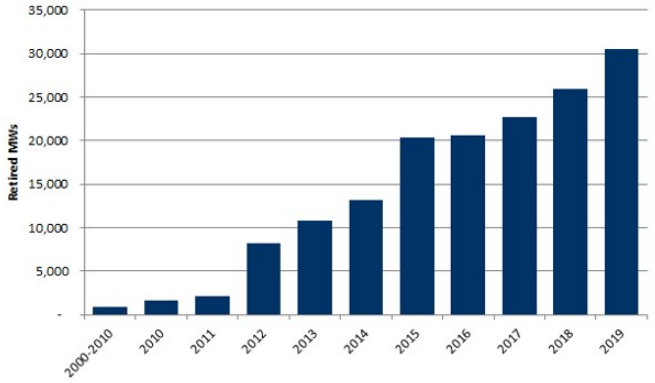
A price on carbon would change these dynamics significantly — With a $40/tCO2e carbon price we see all the coal capacity (11 GWs) at risk. Current all in costs for coal plants are ~$27/MWh and rise to ~$30MWh by 2030. With a $40/tC02e carbon price, costs for coal plants would rise by ~$40/MWh (assumes 1.0 tCO2e/MWh for coal plants) to $67-70/MWh. ERCOT's scarcity pricing dynamic would likely still play the major role in setting mid-summer onpeak prices in ERCOT. However, longer-term onpeak prices will also be influenced by cheap renewables, particularly solar, which has a longer-term LCOE of $25/MWh in our bull case, as well as efficient new CCGTs, which could undercut the more expensive coal and gas plants on the margin. In the carbon pricing scenario, the dispatch costs for combined cycle gas plants would likely be ~$33-34/MWh, which compares to dispatch costs of coal plants of >$60/MWh. As such, in a $40/tCO2e carbon pricing scenario all coal plants would be at risk of shutdown.

PJM (Mid-Atlantic)

The PJM power market is a deregulated (competitive) region covering the Mid-Atlantic and the Eastern edge of the Midwest. This market is generally characterized by challenging economics for solar and wind projects, but favorable economics for natural gas-fired plants given the low cost of gas in the region (which is the location of the Marcellus and Utica shale formations). We have seen >30 GWs of coal-fired plant shutdowns in this region since 2000, driven primarily by the growth of low-cost natural gas-fired power plants.

Exhibit 48:

Cumulative Coal Retirements in PJM

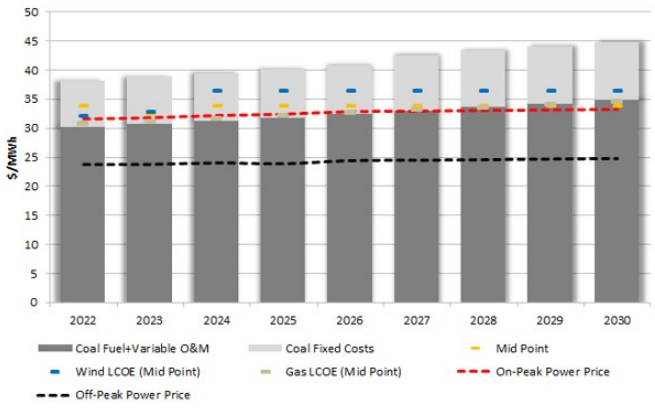


Source: PJM, Morgan Stanley Research

Beyond the ~3 GWs of coal capacity scheduled to retire in the next 2-3 years we project no additional coal-fired plant retirements in the region absent a significant price on carbon, above the low price of carbon established in the Regional Greenhouse Gas Initiative, or RGGI, a carbon pricing scheme that many Mid-Atlantic states have joined. As shown in **Exhibit 49** , the average dispatch cost of coal (fuel + variable O&M costs) in PJM is close to on-peak power prices. In a market without capacity payments this dynamic would drive many plants to become uneconomic, as energy revenues would not be sufficient to cover the fixed costs of operating the plants. That said, we forecast average capacity payments in PJM to be $115-210/MW-day depending on the zone, which compares to the $93-103/MW-day range needed for coal units to break-even. In other words, capacity prices would need to decline by over ~10% in the most conservative case to put these coal units at risk.

Exhibit 49:

PJM — Large Coal Units Avg. Costs vs. Renewables & Gas LCOEs



Source: SNL Financial, Morgan Stanley Research estimates

Our capacity pricing forecasts are based on our gas new build economics model. We set the capacity price by using a gas new build model to calculate the capacity payment needed to make a gas new build plant economic in 2022/23. Given the interrelationship between power price and capacity price (i.e. the higher the power price, the lower the capacity price tends to be), we use the current 2022 forward power prices and natural gas prices to derive the current capacity price payment that is needed. Our analysis indicates that based on recent commodity prices, $115/MW-day capacity pricing is implied in PJM RTO, $125/MW-day in PJM MAAC, $165/MW-day in PJM EMAAC, and $210/MW-day in PJM ComEd. **Exhibit 50** provides an overview of key metrics used to derive capacity prices:

Exhibit 50:

Key metrics used to derive PJM capacity prices that make new builds economic

PJM Areas	PJM West (AD Hub)	PJM MAAC	PJM EMAAC	PJM ComEd
Plant Construction Cost ($/kW)	$900	$950	$1,150	$950
Debt (% of EV)	55%	55%	55%	55%
Interest Rate on Debt	5.0%	5.0%	5.0%	5.0%
Amortizing Debt?	Y	Y	Y	Y
Plant Heat Rate (btu/kWh) - Initial	6,500	6,500	6,500	6,500
Plant Heat Rate (btu/kWh) - Terminal	7,000	7,000	7,000	7,000
On-Peak Capacity Factor (%) - Initial	47.5%	47.5%	47.5%	47.5%
On-Peak Capacity Factor (%) - Terminal	25.0%	25.0%	25.0%	25.0%
Off-Peak Capacity Factor (%) - Initial	35.0%	35.0%	35.0%	35.0%
Off-Peak Capacity Factor (%) - Terminal	10.0%	10.0%	10.0%	10.0%
Fixed O&M ($/kW-yr)	$15	$15	$20	$15
Non-Fuel VOM ($/MWh)	$1.50	$1.50	$1.50	$1.50
Maintenance Capex ($/MWh)	$1.00	$1.00	$1.00	$1.00
2022 Peak Power Price ($/MWh)	$31.3	$33.3	$34.8	$27.0
2022 Off-Peak Power Price ($/MWh)	$23.5	$25.0	$26.5	$19.4
Delivered Gas Price ($/mmBtu)	$2.47	$2.69	$2.69	$2.47
Equity IRR	12.15%	12.31%	12.30%	12.15%
2022 Capacity Price	**$115**	**$125**	**$165**	**$210**

Source: Morgan Stanley Research estimates

Our power price forecasts are based on the 2022 forward prices and YoY pricing changes based on our PJM dispatch model. We calculate YoY changes in onpeak and offpeak prices through our dispatch model. We also set onpeak pricing for PJM (versus only offpeak pricing for ERCOT) given that it does not have the same scarcity pricing mechanism as ERCOT has. 2022 prices are set by the forward curve, but the years after reflect a YoY change in prices calculated from the dispatch model. Key inputs to the dispatch model (please ask us for a copy), include:

- Demand data (from ISO/RTO website)
- Supply data (from SNL and ISO/RTO website)
- New build
- Retirements
- Fuel costs ($/MWh)
- Non-fuel variable operating costs ($/MWh)

Implications of a Price on Carbon

A price on carbon would change these dynamics significantly — With a $40/tCO2e carbon price we see all the coal capacity (26 GWs) at risk. Current all in costs for coal plants are ~$38/MWh and rise to ~$45/MWh by 2030. With a $40/tC02e carbon price, costs for coal plants would rise by ~$40/MWh (assumes 1.0 tCO2e/MWh for coal plants) to $78-85/MWh. A mixture of primarily coal and gas plants currently set the onpeak price in the PJM market, so we think the increase in energy market pricing will be less than the carbon cost to coal plants, pressuring margins. Additionally, new renewables such as wind would be increasingly competitive against much higher market prices. Our analysis of renewables LCOEs determines that longer-term LCOES in PJM are $23-50/MWh for wind and $24-44/MWh for solar. As a result, the dispatch cost for coal plants >$70/MWh would be significantly above longer-term power prices in PJM.

We view EXC as the main beneficiary of a carbon tax given its large merchant nuclear fleet of 20GWs, which represents 61% of its total merchant capacity. For reference, applying a $10/MWh increase in power prices to EXC's non-carbon emitting generation in 2020 drives a $1.6bn (or 20%) increase in the company's 2020 margins — non-carbon emitting power plants, such as those of EXC, benefit from higher margins given that a tax on carbon drives market clearing prices to increase, as the variable costs of running fossil fuel plants increase. **PEG would also benefit, given that >30% of the company's operating capacity and >55% of net generation is derived from its three nuclear plants.**

NYISO

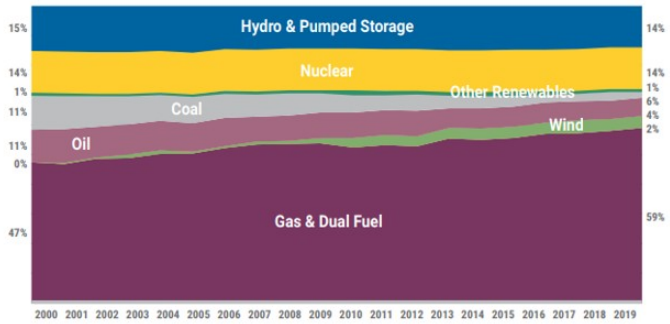
Little remaining coal generation exists in the New York ISO (NYISO), and as such we have not drawn the same comparison of wind and solar LCOE vs. variable and fixed coal costs. In this section we highlight the state and ISO's transition toward 100% clean energy, which is supported by state policy initiatives to reduce emissions.

Key New York state environmental regulations and energy policies:

- 100% carbon free energy by 2040, and net-zero emissions by 2050 with the use of carbon offsets. Interim decarbonization target for >70% of the state's electricity to be generated by renewables by 2030.
- Develop 2,400 MW of offshore wind capacity by 2030, and 9,000 GW by 2035.
- 1,500 MW of battery storage capacity by 2025, and 3,000 MW by 2030.
- 6,000 MW of solar capacity by 2025.
- >26 GW of installed capacity in NY participates in RGGI, and the state is seeking to reduce the allowed emission cap by 30% between 2020-30.

Exhibit 51:

New York State Fuel Mix Trends: Capacity 2000-19

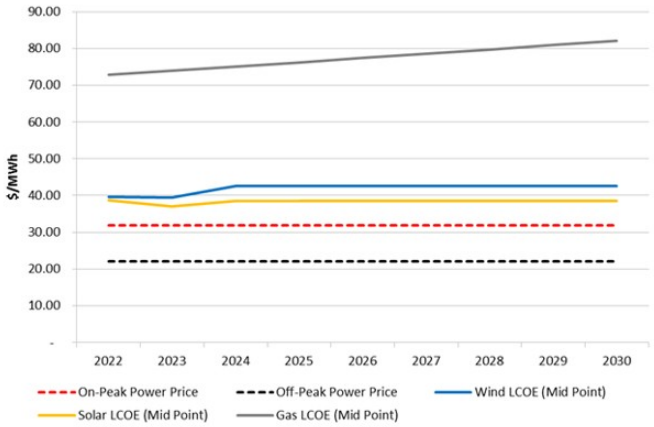


Source: NYISO — Power Trends 2019

New York already has a relatively low-carbon generation profile compared to other states, primarily because of the state's four nuclear power plants, and its large hydroelectric fleet. In 2018, 5% of New York's power came from solar and wind, but total zero-carbon generation accounted for >50%, with 32% nuclear and 22% hydropower. The remaining 41% was generated by natural-gas fired resources. With the planned retirement of the Indian Point nuclear facility in 2020/21, the state is expected to lose ~2,000 MW of carbon free generation. The other three upstate nuclear plants, which are already subsidized via Zero Emission Credits (ZECs), are not likely to retire until 2030. However, the State's push to reach 100% carbon free generation by 2040 will involve backfilling the ~32% of net generation that comes from nuclear power before making incremental progress toward 100% carbon-free. Also, with onshore wind development largely expected in the western part of the state, and with load centers (NYC) primarily downstate, a significant build-out of large-scale transmission will likely be required.

Exhibit 52:

MSe New Resource LCOE Comparison for NYISO

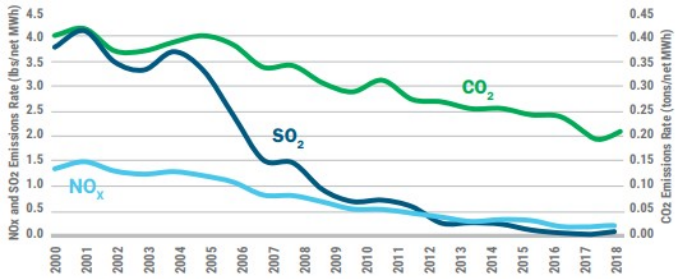


Source: Morgan Stanley Research estimates. Note: this chart includes midpoint LCOEs rather than highlighting the most economic projects

At the electric power sector level, New York has reduced carbon emissions by >60% since 2005, primarily by eliminating emissions from coal and petroleum-fueled generation. At at total state level, across the residential, C&I, transportation, and electric power sectors, emissions have declined >25% since 2005.

Exhibit 53:

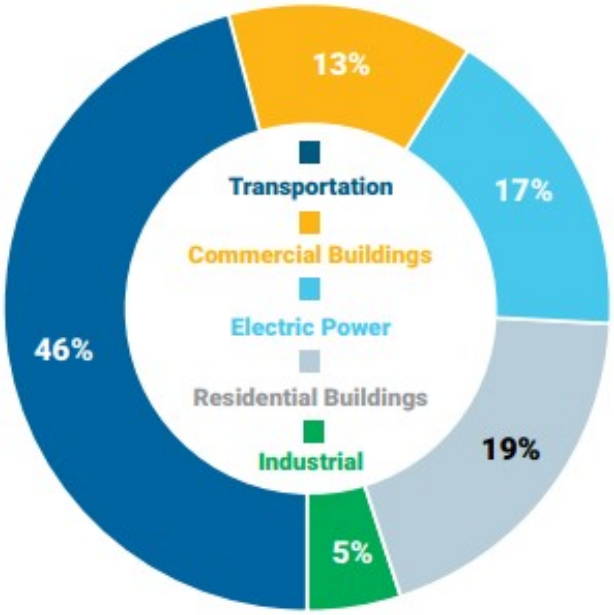
Emissions Rates from Electric Generation in New York: 2000-18



Source: US EPA, EIA, NYISO

Exhibit 54:

New York State Energy-Related CO2 Emissions by Sector



Source: EIA, NYISO

ISO-NE

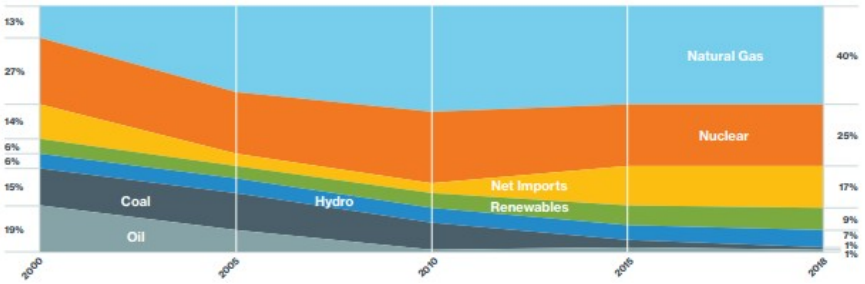
ISO-New England is made up of six states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Similarly to New York and California, there is an energy transition underway in New England — a shift away from conventional generation to renewable energy, from centrally dispatched generation to distributed energy resources, and a growing focus on carbon reduction.

Two large nuclear facilities have recently closed in the ISO-NE market — Vermont Yankee and Pilgrim. The region's two remaining nuclear facilities (Millstone and Seabrook) will be critical to meeting clean energy and reliability goals. Aging coal-fired and oil-fired capacity in the region (and the two retired nuclear facilities) is closing mainly because fuel and environmental mitigation costs make these units too expensive to compete effectively against natural gas and renewables.

Wind power, predominantly offshore, dominates new resource proposals in New England. The amount of new wind power seeking interconnection in New England (over a multi-year period) is >4x the amount of natural gas-fired generation proposed. Of the roughly 13,500 MW (nameplate) of wind power being proposed across ISO-NE (as of Jan. 2019), ~9,500 MW would be offshore of Massachusetts, Rhode Island, and Connecticut, with most of the remaining 4,000 MW located onshore in Maine. That 9,500MW today is ~37% and 46% of NE-ISO's 2018 Summer and Winter Peak loads, respectively, and ~25% of the market's 2018 operating capacity. Massachusetts utilities have executed contracts (subject to regulatory approval) for 800 MW of offshore wind to be on line by 2023, with plans for an additional 800 MW of offshore wind by 2027. Connecticut and Rhode Island utilities have also negotiated contracts for offshore wind to be on line by 2023.

Exhibit 55:

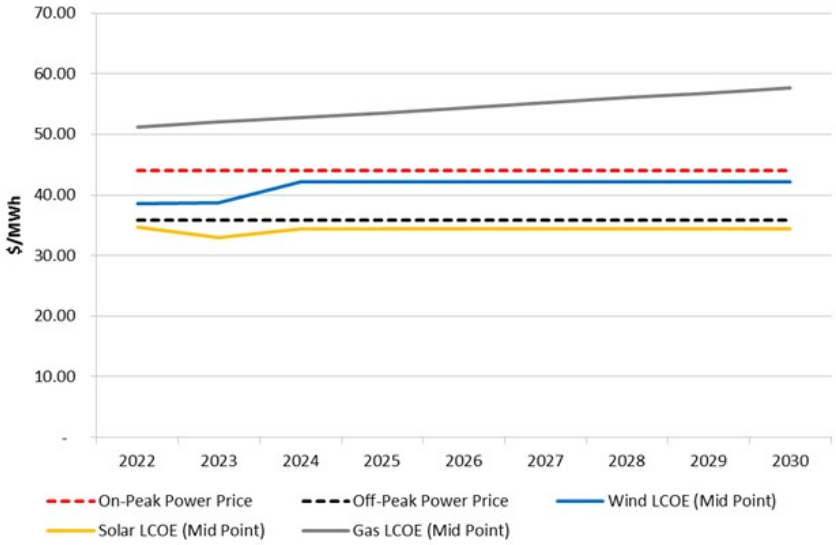
Sources of Grid Electricity in New England (Annual Net Energy Consumed, MWh)



Source: ISO New England, generation data, and *Net Energy and Peak Load by Source Report*

Exhibit 56:

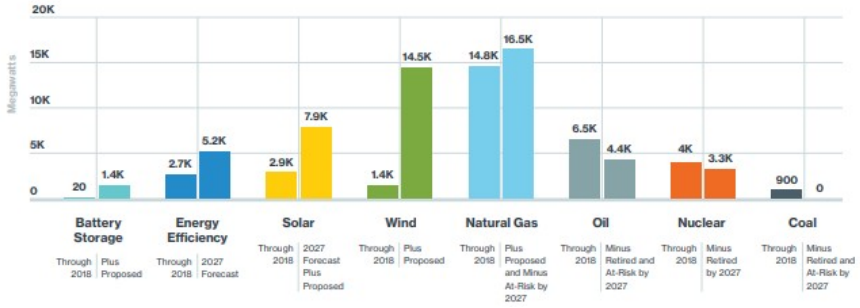
MSe New Resource LCOE Comparison for ISO-NE



Source: Morgan Stanley Research estimates. Note: this chart includes midpoint LCOEs rather than highlighting the most economic projects

Exhibit 57:

Projected Changes in Key New England Power Resources and Energy Efficiency



Source: ISO-NE. https://www.iso-ne.com/about/key-stats/resource-mix

At the electric power sector level, the six ISO-NE states combined have reduced carbon emissions by >45% since 2005, primarily by eliminating emissions from coal and petroleum-fueled generation. In total, across the residential, C&I, transportation, and electric power sectors, emissions have declined >20% since 2005.

NE-ISO states are all part of the Regional Greenhouse Gas Initiative (RGGI), and all have renewable portfolio standards (source):

- **CT:** 44% by 2030
- **MA:** 35% by 2030 and an additional 1% each year after
- **ME:** 80% by 2030; statewide target of 100% renewables by 2050
- **NH:** 25.2% by 2025
- **RI:** 14.5% by 2019, with increases of 1.5% each year until 38.5% by 2035
- **VT**: 55% by 2017; 75% by 2032

Greenhouse gas emissions targets for all ISO-NE states (source):

- **CT:** Enacted targets in 2009 for reducing emissions: 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In 2018, a law was signed to set a 45% GHG reduction target by 2030.
- **MA:** Enacted targets in 2008 for reducing emissions: 25% below 1990 levels by 2020 and 80% below 1990 levels by 2050.
- **ME:** Enacted targets in 2019 for reducing emissions: 45 percent below 1990 levels by 2030 and at least 80 percent by 2050.
- **NH:** Announced targets in 2009 for reducing emissions: 80% below 1990 levels by 2050 and a short-term target of 20% below 1990 levels by 2025. Previously in 2001, New Hampshire had enacted a target of 1990 levels by 2010, 10% below 1990 levels by 2020, and 75-85% below 2001 levels in the long term.
- **RI:** Enacted targets in 2014 for reducing emissions: 10% below 1990 levels by 2020, 45% below 1990 levels by 2035, and 80% below 1990 levels by 2050.
- **VT:** Enacted targets in 2007 for reducing emissions: 25% below 1990 levels by 2012 and 50% below 1990 levels by 2028. And ,if applicable, use reasonable efforts to reach 75% by 2050.

Exhibit 58:

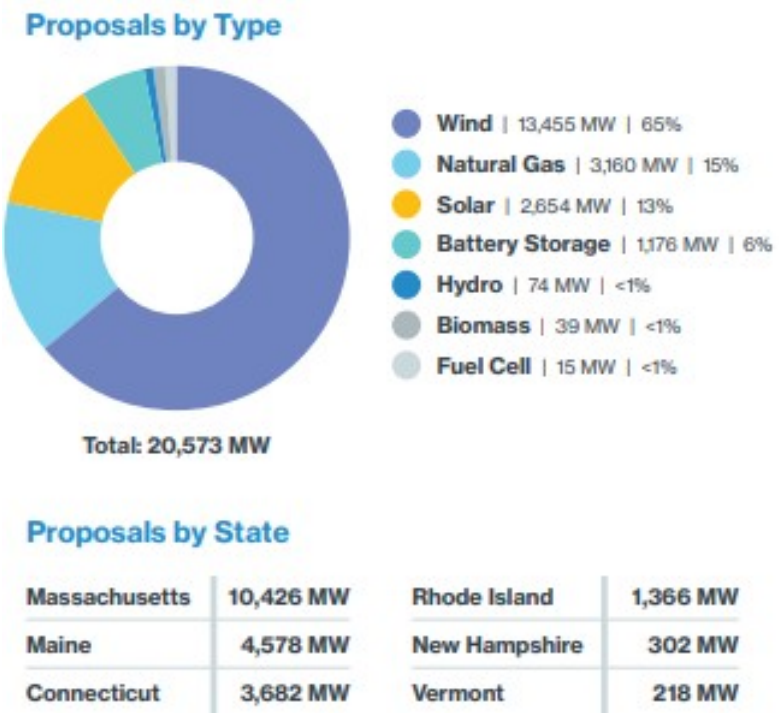
Overall ISO-NE Emissions Reductions from 2005 Levels (million metric tons of CO2)

	CT	MA	ME	NH	RI	VT	ISO-NE
Electric Power (EP) Emissions - 2005	10	24.8	3.8	7.8	2.4	0	48.8
Electric Power (EP) Emissions - 2017	6.3	12.7	1.4	3.3	2.6	0	26.3
Total State Emissions - 2005	43.8	84	23	21.2	11.1	6.8	189.9
Total State Emissions - 2017	33.6	65.2	16.5	14.2	10.1	5.7	145.3
% Chg, EP Emissions	-37%	-49%	-63%	-58%	8%	N/A	-46%
% Chg, Total Emissions	-23%	-22%	-28%	-33%	-9%	-16%	-23%

Source: Morgan Stanley Research. EIA.

Exhibit 59:

New Energy Proposals by Type and State — Wind Dominates



Source: ISO Generator Interconnection Queue (January 2019). Note: Not all proposed new projects are built; historically, 70% of megawatts have ultimately withdrawn

CAISO

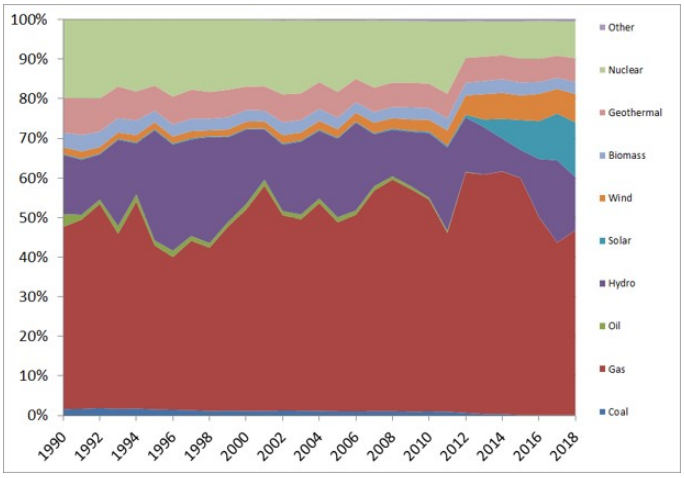
California has long been the US leader in pursuing a low carbon future. The state's generation resource mix (and penetration of renewables) and emission profile are setting the pace of and precedent for decarbonization in the US. In 2018, California committed to economy-wide carbon neutrality by 2045. The state enacted targets in 2005 for reducing emissions: 2000 levels by 2010, 1990 levels by 2020, and 80% below 1990 levels by 2050. In 2015, the state also issued an interim emissions reduction goal of 40% below 1990 levels by 2030. As you can see in **Exhibit 60** below, coal represents <1% of the state energy mix, natural gas has fluctuated between 40% - 60% of mix, and solar has increased from <1% of mix in 2010, to ~14% as of 2018.

Emissions from electricity production have declined by ~21% since 2005 (granted, this is starting from a low baseline level relative to other states), and total state emissions have declined by ~5% over the same period.

The state has adopted a renewable portfolio standard, which calls for renewables penetration of: 44% by 2024, 52% by 2027, 60% by 2030. The standard also requires 100% clean energy by 2045.

Exhibit 60:

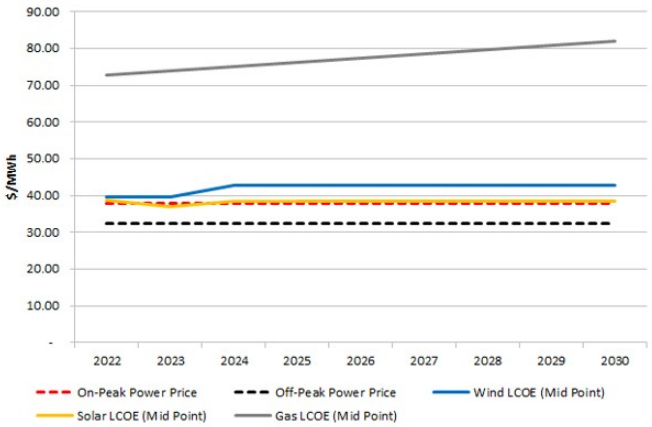
Generation Mix in California (% MWh) from 1990 - 2018



Source: Morgan Stanley Research

Exhibit 61:

MSe New Resource LCOE Comparison for CAISO



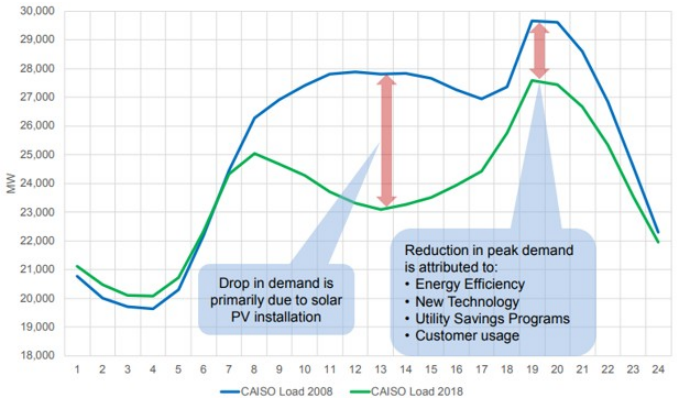
Source: Morgan Stanley Research estimates. Note: this chart includes midpoint LCOEs rather than highlighting the most economic projects

The California "duck curve" illustrates the complexities of operating the grid in California. Over the last decade, a tremendous amount of solar capacity has been installed in the state (especially distributed, rooftop solar), which has had the effect of reducing CAISO load in the middle of the day when the solar resource is greatest. In turn, this creates a significant ramp in demand (on a typical spring day) from ~12,000 MW at the "belly of the duck" around 2pm, to >26,000 MW by 8pm peak. On Jan. 1, 2019, for example, an actual 3-hour ramp (5pm - 8pm) of 15,639 MW was realized. This dynamic creates challenges, as fast-ramping resources need to be available to meet peak load, and there is the risk of over-generation / oversupply midday. Oversupply is when all anticipated generation, including renewables, exceeds the real-time demand for electricity. If the market cannot automatically manage oversupply, manual intervention is required to maintain reliability. In an extreme example, wholesale prices can go negative and generators actually have to pay utilities to take energy. Aside from potentially expanding the ISO control area (to increase midday demand) or increasing participation in the western Energy Imbalance Market (which has allowed the state to export negatively priced power to Arizona), the state will: **(A)** seek to transition cars and trucks to electricity (and the EVs will be incentivized to charge midday), will **(B)** offer consumers time-of-use rates that promote using electricity during the day (vs. peak hours) when solar is plentiful and there is risk of oversupply, **(C)** increase energy storage capacity, and **(D)** potentially increase the

flexibility of power plants to more quickly follow ISO instructions to change generation output levels. This dynamic has also created a need for fast-ramping natural gas peaking plants to remain online in California to maintain reliability (eg. on reliability must run (RMR) contracts).

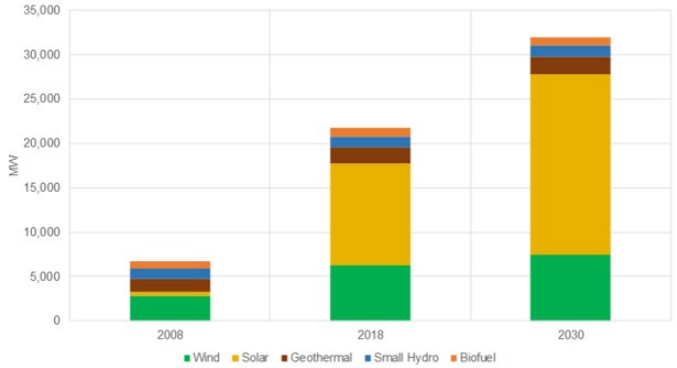
To address the complexities discussed above, the state has additional energy-related goals, including to have 5 million EVs on the road by 2030 (which necessitates a $2.5Bn investment in new charging stations), 10,000 MW of distributed generation by 2021, and 1.3 GW of battery storage by 2024.

Exhibit 62:
Average of CAISO's Load for Five Consecutive Weekdays, March 2008 vs. March 2018



Source: CAISO

Exhibit 63:
CAISO's Expectation is that the Growth of Renewables to Achieve 60% by 2030 Will Predominantly Come from Solar Power



Source: CAISO

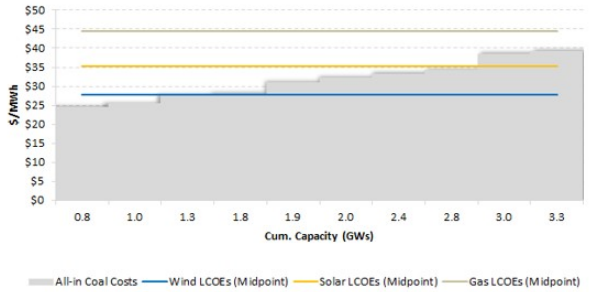
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Appendix — Coal Economics by Regulated State

Midwest

Exhibit 64:

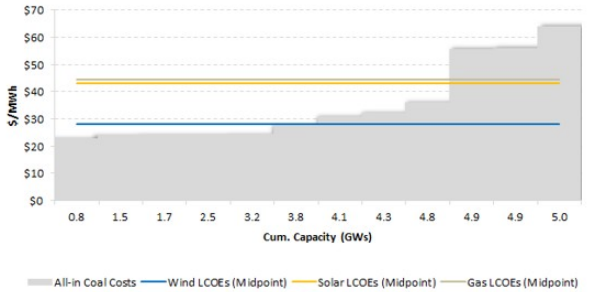
Colorado - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 65:

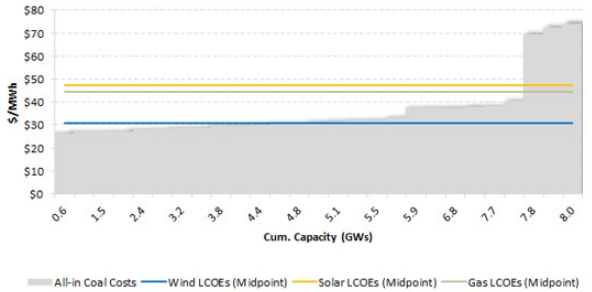
Iowa - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 66:

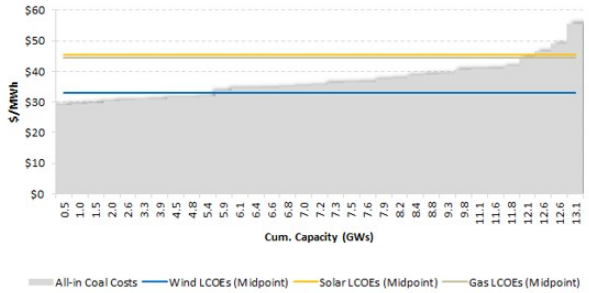
Illinois - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 67:

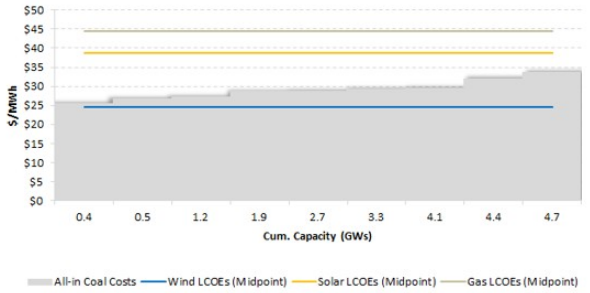
Indiana - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 68:

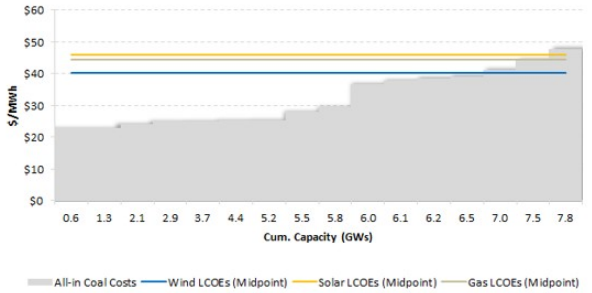
Kansas - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 69:

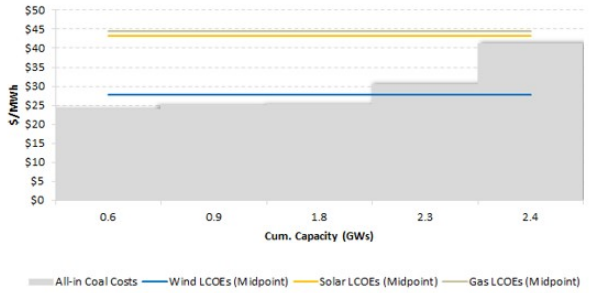
Michigan - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 70:

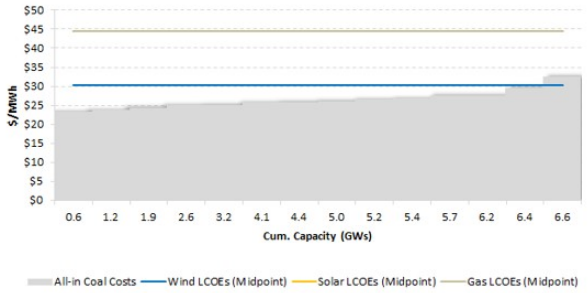
Minnesota - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 71:

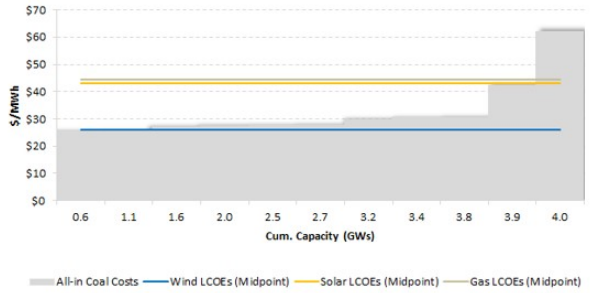
Missouri - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 72:

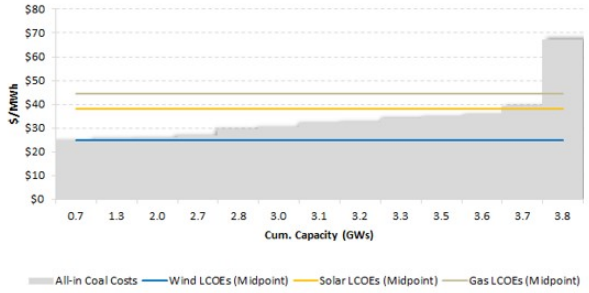
North Dakota - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 73:

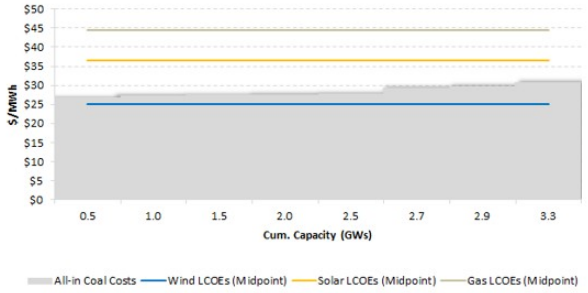
Nebraska - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 74:

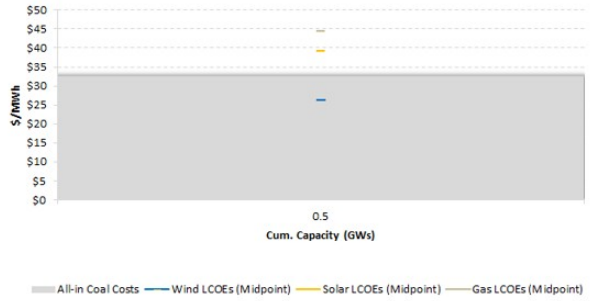
Oklahoma - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 75:

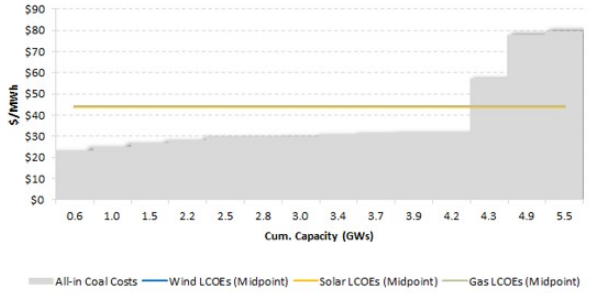
South Dakota- Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 76:

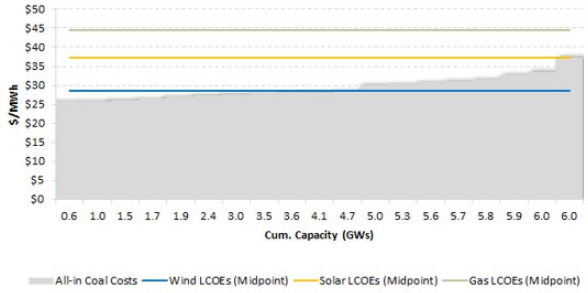
Wisconsin - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 77:

Wyoming - Coal Economics by 2030 Under Scenario 3



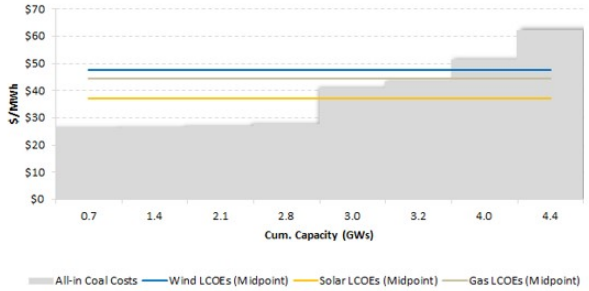
Source: SNL Financial, Morgan Stanley Research

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FOUNDATION

Southeast

Exhibit 78:

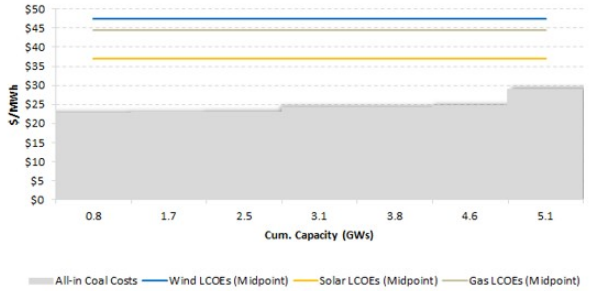
Alabama - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 79:

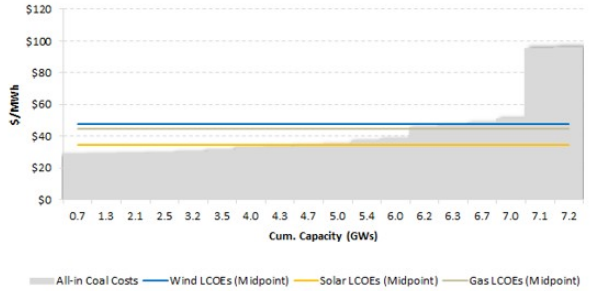
Arkansas - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 80:

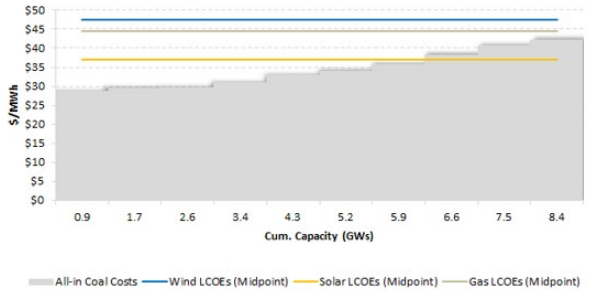
Florida - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 81:

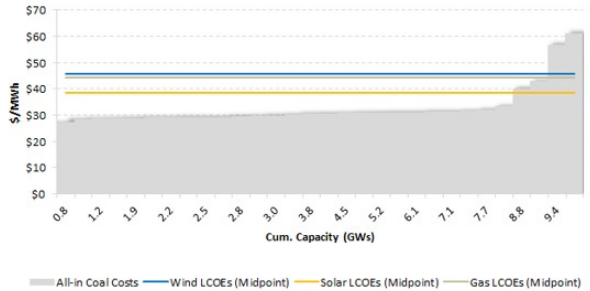
Georgia - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 82:

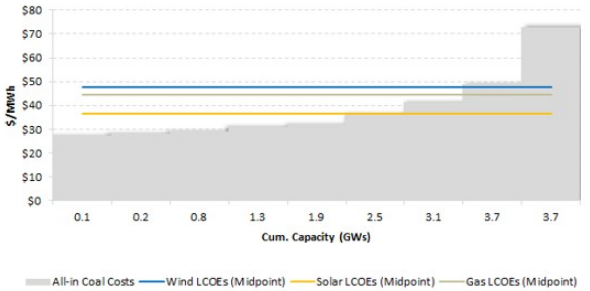
Kentucky - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 83:

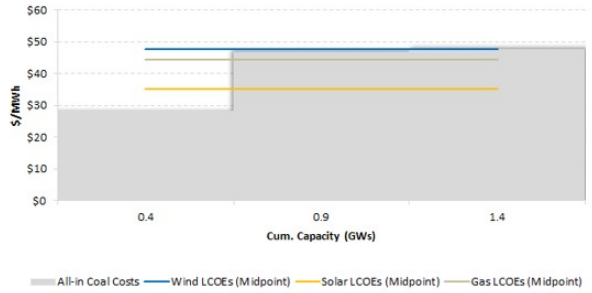
Louisiana - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 84:

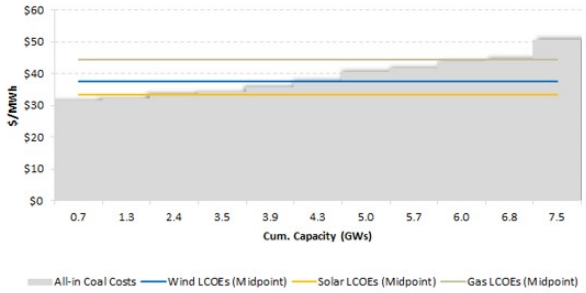
Mississippi - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 85:

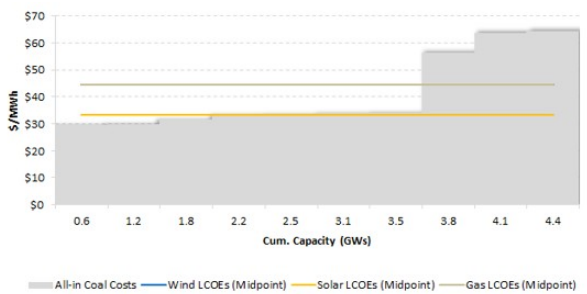
North Carolina - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 86:

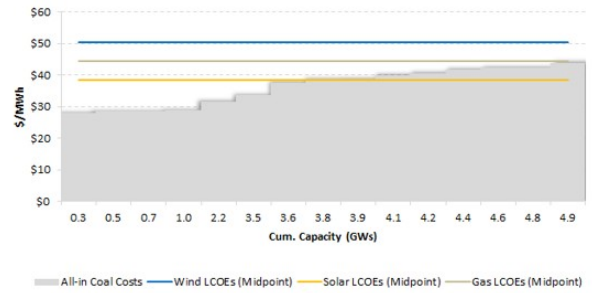
South Carolina - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 87:

Tennessee - Coal Economics by 2030 Under Scenario 3



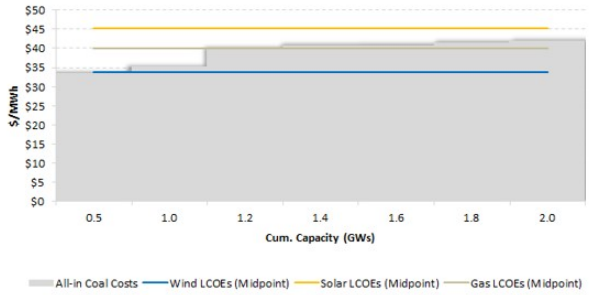
Source: SNL Financial, Morgan Stanley Research

Sierra Club/202
Posner/48
FOUNDATION

MidAtlantic

Exhibit 88:

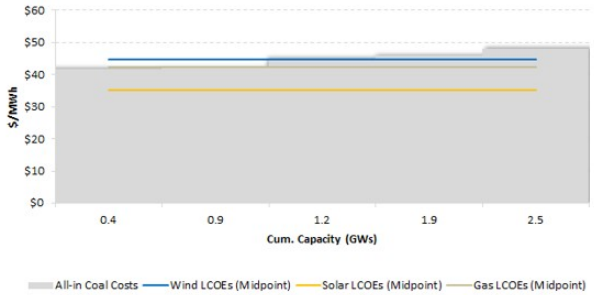
Ohio - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

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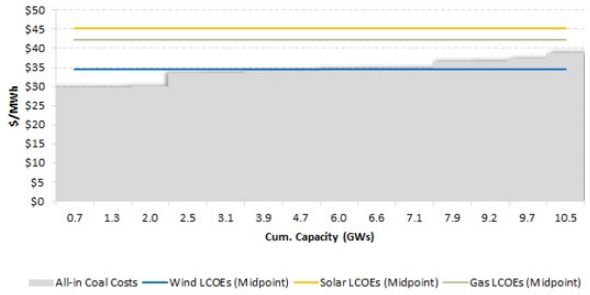
Virginia - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 90:

West Virginia - Coal Economics by 2030 Under Scenario 3

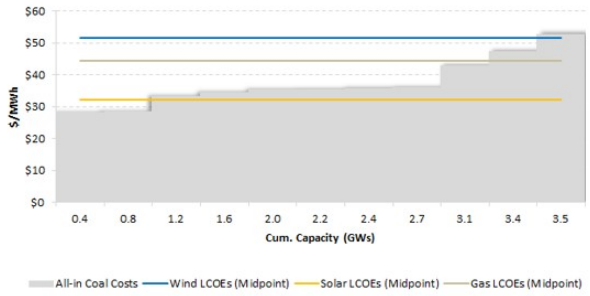


Source: SNL Financial, Morgan Stanley Research

Southwest

Exhibit 91:

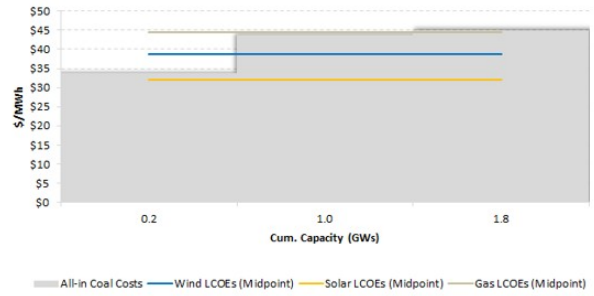
Arizona - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 92:

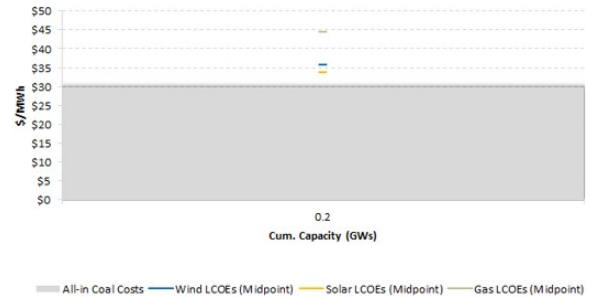
New Mexico - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 93:

Nevada - Coal Economics by 2030 Under Scenario 3



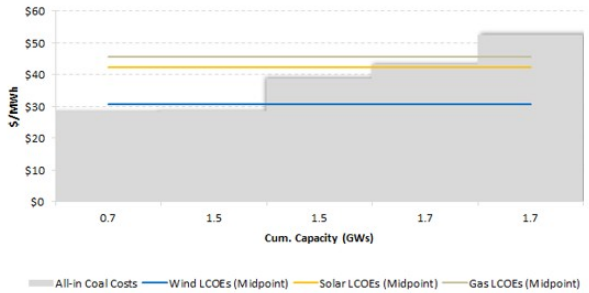
Source: SNL Financial, Morgan Stanley Research

Sierra Club/202
Posner/49
FOUNDATION

Northwest

Exhibit 94:

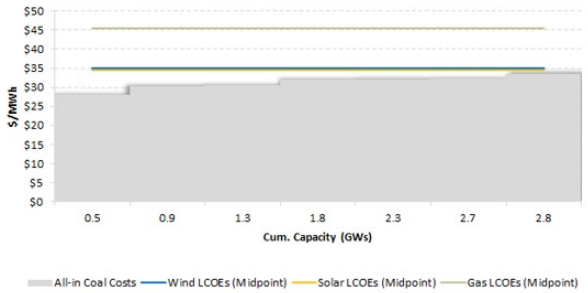
Montana - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Exhibit 95:

Utah - Coal Economics by 2030 Under Scenario 3



Source: SNL Financial, Morgan Stanley Research

Disclosure Section

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Analyst Certification

The following analysts hereby certify that their views about the companies and their securities discussed in this report are accurately expressed and that they have not received and will not receive direct or indirect compensation in exchange for expressing specific recommendations or views in this report David Arcaro, CFA; Stephen C Byrd; Ethan C Ellison; Devin McDermott; Mark Savino

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Global Stock Ratings Distribution

(as of November 30, 2019)

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	Coverage Universe		Investment Banking Clients (IBC)			Other Material Investment Services Clients (MISC)	
Stock Rating Category	Count	% of Total	Count	% of Total IBC	% of Rating Category	Count	% of Total Other MISC
Overweight/Buy	1150	36%	287	42%	25%	515	36%
Equal-weight/Hold	1452	46%	317	47%	22%	692	48%
Not-Rated/Hold	1	0%	0	0%	0%	1	0%
Underweight/Sell	563	18%	73	11%	13%	222	16%
Total	3,166		677			1430	

Data include common stock and ADRs currently assigned ratings Investment Banking Clients are companies from whom Morgan Stanley received investment banking compensation in the last 12 months Due to rounding off of decimals, the percentages provided in the "% of total" column may not add up to exactly 100 percent

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Equal-weight (E) The stock's total return is expected to be in line with the average total return of the analyst's industry (or industry team's) coverage universe, on a risk-adjusted basis, over the next 12-18 months

Not-Rated (NR) Currently the analyst does not have adequate conviction about the stock's total return relative to the average total return of the analyst's industry (or industry team's) coverage universe, on a risk-adjusted basis, over the next 12-18 months

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Unless otherwise specified, the time frame for price targets included in Morgan Stanley Research is 12 to 18 months

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Attractive (A) The analyst expects the performance of his or her industry coverage universe over the next 12-18 months to be attractive vs the relevant broad market benchmark, as indicated below

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Benchmarks for each region are as follows North America - S&P 500; Latin America - relevant MSCI country index or MSCI Latin America Index; Europe - MSCI Europe; Japan - TOPIX; Asia - relevant MSCI country index or MSCI sub-regional index or MSCI AC Asia Pacific ex Japan Index

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INDUSTRY COVERAGE: Regulated Utilities

COMPANY (TICKER)	RATING (AS OF)	PRICE* (12/09/2019)
Stephen C Byrd		
Ameren Corp (AEE.N)	E (06/06/2018)	$74.95
Atmos Energy Corp. (ATO.N)	O (09/21/2018)	$106.31
CenterPoint Energy Inc (CNP.N)	E (06/05/2019)	$25.04
CMS Energy Corp (CMS.N)	E (07/31/2017)	$61.28
Conso idated Edison Inc (ED.N)	U (01/09/2017)	$86.56
Duke Energy Corp (DUK.N)	E (08/25/2014)	$89.28
Edison International (EIX.N)	E (01/12/2015)	$71.01
Entergy Corp (ETR.N)	E (09/06/2019)	$118.18
Eversource Energy (ES.N)	E (02/13/2018)	$80.72
FirstEnergy Corp (FE.N)	E (11/05/2019)	$48.12
ONE Gas Inc (OGS.N)	U (03/18/2016)	$88.46
PG&E Corp (PCG.N)	E (11/15/2018)	$11.18
Pinnacle West Capital Corp (PNW.N)	U (06/12/2019)	$85.55
PPL Corp (PPL.N)	E (07/16/2013)	$33.71
Sempra Energy (SRE.N)	E (08/10/2018)	$145.83
Southern Company (SO.N)	U (08/13/2014)	$61.44
South Jersey Industries Inc (SJI.N)	E (09/08/2016)	$30.70
Spire Inc (SR.N)	U (01/12/2016)	$79.28
Xcel Energy Inc (XEL.O)	E (09/21/2018)	$61.73

Stock Ratings are subject to change. Please see latest research for each company.

* Historical prices are not spl t adjusted.

INDUSTRY COVERAGE: Diversified Utilities / IPPs

COMPANY (TICKER)	RATING (AS OF)	PRICE* (12/09/2019)
Stephen C Byrd		
AES Corp. (AES.N)	E (04/27/2018)	$18.79
American Electric Power Co (AEP.N)	E (04/18/2019)	$91.86
Dominion Energy Inc (D.N)	E (08/07/2019)	$79.92
Exelon Corp (EXC.O)	O (08/27/2019)	$44.93
NextEra Energy Inc (NEE.N)	O (07/22/2014)	$234.27
NRG Energy Inc (NRG.N)	O (09/06/2019)	$38.56
Public Service Enterprise Group Inc (PEG.N)	O (09/21/2017)	$57.89
Vistra Energy Corp (VST.N)	O (03/25/2019)	$23.67

Stock Ratings are subject to change. Please see latest research for each company.

* Historical prices are not spl t adjusted.

INDUSTRY COVERAGE: Clean Tech

COMPANY (TICKER)	RATING (AS OF)	PRICE* (12/09/2019)
Ethan C Ellison		
TPI Composites Inc. (TPIC.O)	O (10/29/2018)	$16.95
Stephen C Byrd		
Bloom Energy Corp. (BE.N)	O (08/20/2018)	$5.33
First Solar Inc (FSLR.O)	E (02/07/2011)	$52.44
Hannon Armstrong (HASI.N)	E (02/03/2016)	$29.79
Plug Power Inc. (PLUG.O)	E (04/09/2015)	$3.00
SunPower Corp (SPWR.O)	U (09/27/2017)	$7.23
Sunrun Inc (RUN.O)	E (08/03/2018)	$13.31

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The Americas
1585 Broadway
New York, NY 10036-8293
United States
Tel: +1 (1) 212 761 4000

Europe
20 Bank Street, Canary Wharf
London E14 4AD
United Kingdom
Tel: +44 (0) 20 7 425 8000

Japan
1-9-7 Otemachi, Chiyoda-ku
Tokyo 100-8104
Japan
Tel: +81 (0) 3 6836 5000

Asia/Pacific
1 Austin Road West
Kowloon
Hong Kong
Tel: +852 2848 5200

Docket No. UE 374
Exhibit Sierra Club/203
Witness: David B. Posner

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

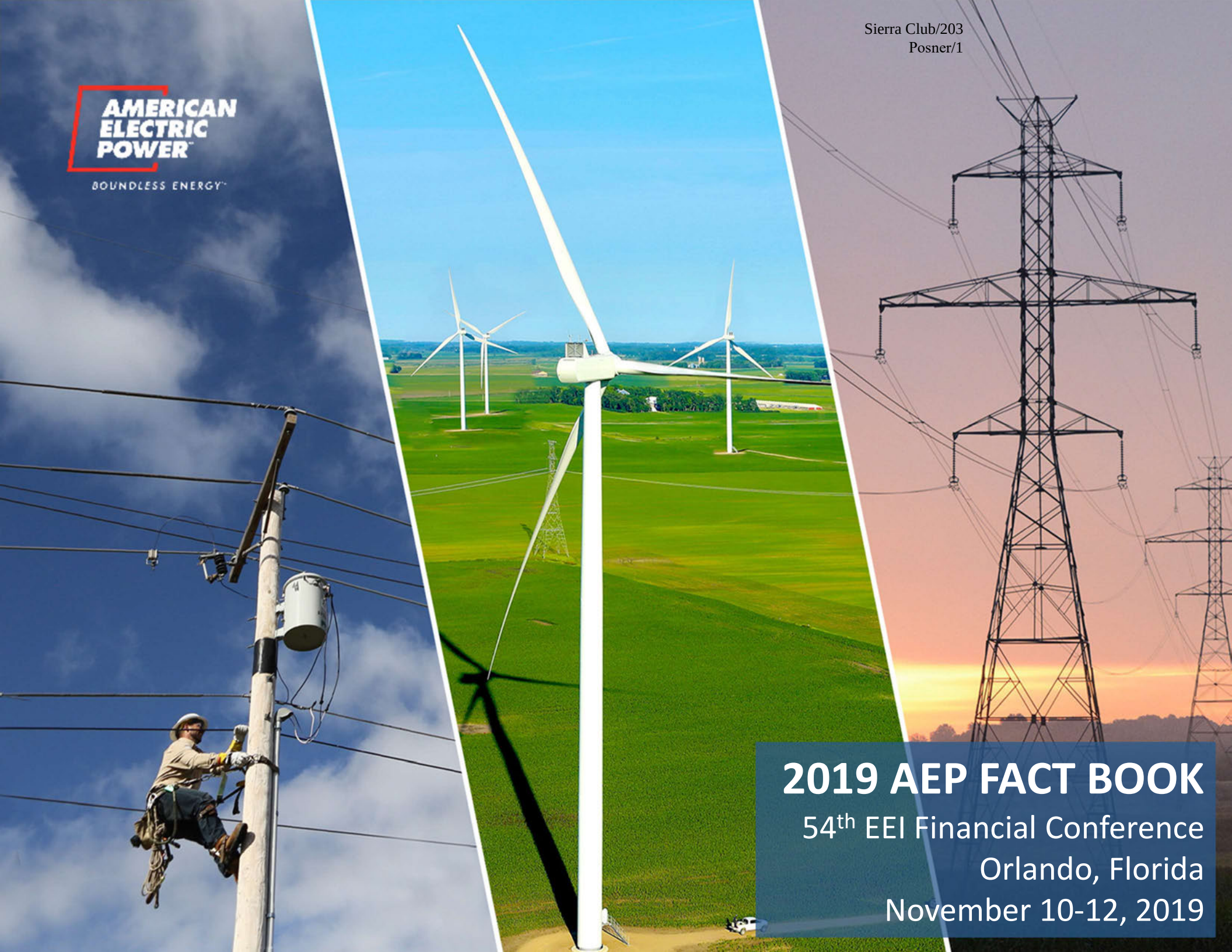
SIERRA CLUB EXHIBIT 203

Exhibits Accompanying the Opening Testimony of David B. Posner

2019 AEP Fact Book

AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY™



2019 AEP FACT BOOK

54th EEI Financial Conference
Orlando, Florida
November 10-12, 2019

AEP Credit Ratings

Current Ratings for AEP, Inc. & Subsidiaries

Company	Moody's Senior Unsecured	Moody's Outlook	S&P Senior Unsecured	S&P Outlook
American Electric Power Company Inc.	Baa1	S	BBB+	S
AEP, Inc. Short Term Rating	P2	S	A2	S
AEP Texas Inc.	Baa1	S	A-	S
AEP Transmission Company, LLC[1]	A2	S	A-	S
Appalachian Power Company[2]	Baa1	S	A-	S
Indiana Michigan Power Company[2]	A3	S	A-	S
Kentucky Power Company	Baa3	S	A-	S
AEP Ohio	A2	S	A-	S
Public Service Company of Oklahoma	A3	S	A-	S
Southwestern Electric Power Company	Baa2	S	A-	S
Transource Energy[3]	A2	S	NR	NR

[1] AEP Transmission Co. received a senior unsecured debt rating of A- from Fitch. The rating outlook is Stable.

[2] In conjunction with the unenhanced VRDN remarketings, APCo and I&M both received short term credit ratings of A-2/P2 from S&P and Moody's, respectively.

[3] NR stands for Not Rated

Ratings current as of September 30, 2019

Docket No. UE 374
Exhibit Sierra Club/204
Witness: David B. Posner

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 204

Exhibits Accompanying the Opening Testimony of David B. Posner

Alliant Energy Form 10-K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2019

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the trans t on per od from to

Name of Reg s an , S a e of Inco po a on, Add ess of P nc pal Execu ve Off ces, Telephone Numbe , Comm ss on F le Numbe , IRS Employe Iden f ca on Numbe

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(a Wisconsin Corporation)
4902 N Biltmore Lane
Madison, Wisconsin 537 8
Telephone (608) 458 33
Commission File Number 9894
IRS Employer Identification Number 39 380265

INTERSTATE POWER & LIGHT COMPANY
(an Iowa corporation)
Alliant Energy Tower
Cedar Rapids, Iowa 5240
Telephone (3 9) 786 44
Commission File Number 4 7
IRS Employer Identification Number 42 033 370

WISCONSIN POWER & LIGHT COMPANY
(a Wisconsin corporation)
4902 N Biltmore Lane
Madison, Wisconsin 537 8
Telephone (608) 458 33
Commission File Number 0 337
IRS Employer Identification Number 39 07 4890

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Interstate Power and Light Company, 5 00% Series D Cumulative Perpetual Preferred Stock, $0 0 Par Value, Trading Symbol IPLDP, Nasdaq Global Select Market

Securities registered pursuant to Section 2(g) of the Act: None
Indicate by check mark if the registrants are well known seasoned issuers, as defined in Rule 405 of the Securities Act
Alliant Energy Corporation Yes ☒ No
Interstate Power and Light Company Yes ☒ No
Wisconsin Power and Light Company Yes ☒ No

Indicate by check mark if the registrants are not required to file reports pursuant to Section 3 or Section 5(d) of the Act
Alliant Energy Corporation Yes No ☒
Interstate Power and Light Company Yes No ☒
Wisconsin Power and Light Company Yes No ☒

Indicate by check mark whether the registrants ( ) have filed all reports required to be filed by Section 3 or 5(d) of the Securities Exchange Act of 934 during

the preceding 2 months (or for such shorter period that the registrants were required to file such reports) and (2) have been subject to such filing requirements for the past 90 days

Alliant Energy Corporation Yes ☒ No
Interstate Power and Light Company Yes ☒ No
Wisconsin Power and Light Company Yes ☒ No

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S T (§232 405 of this chapter) during the preceding 2 months (or for such shorter period that the registrants were required to submit such files)

Alliant Energy Corporation Yes ☒ No
Interstate Power and Light Company Yes ☒ No
Wisconsin Power and Light Company Yes ☒ No

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non accelerated filers, smaller reporting companies, or emerging growth companies See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 2b 2 of the Exchange Act

Alliant Energy Corporation Large Accelerated Filer Accelerated Filer Non accelerated Filer Smaller Reporting Company Emerging Growth Company

Interstate Power and Light Company Large Accelerated Filer Accelerated Filer Non accelerated Filer Smaller Reporting Company Emerging Growth Company

Wisconsin Power and Light Company Large Accelerated Filer Accelerated Filer Non accelerated Filer Smaller Reporting Company Emerging Growth Company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 3(a) of the Exchange Act

Alliant Energy Corporation
Interstate Power and Light Company
Wisconsin Power and Light Company

Indicate by check mark whether the registrants are shell companies (as defined in Rule 2b 2 of the Exchange Act)

Alliant Energy Corporation Yes No
Interstate Power and Light Company Yes No
Wisconsin Power and Light Company Yes No

The aggregate market value of the voting and non voting common equity held by nonaffiliates as of June 30,20 9:

Alliant Energy Corporation $ 6 billion
Interstate Power and Light Company $0
Wisconsin Power and Light Company $0

Number of shares outstanding of each class of common stock as ofJanuary 3 , 2020:

Alliant Energy Corporation, Common Stock, $0 0 par value,245,03 ,0 9 shares outstanding

Interstate Power and Light Company, Common Stock, $2 50 par value, 3,370,788 shares outstanding (all outstanding shares are owned beneficially and of record by Alliant Energy Corporation)

Wisconsin Power and Light Company, Common Stock, $5 par value, 3,236,60 shares outstanding (all outstanding shares are owned beneficially and of record by Alliant Energy Corporation)

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement relating to Alliant Energy Corporation’s2020 Annual Meeting of Shareowners are, or will be upon filing with the Securities and Exchange Commission, incorporated by reference into Part III hereof

defaulting borrower under the credit agreement immediately due and payable At December 3 , 20 9, Alliant Energy, IPL and WPL were in compliance with financial covenants of the credit agreement

Long term Debt Refer to Note 9(b) for discussion of issuances and retirements of long term debt in20 9 and "Results of Operations" for discussion of expected issuances of long term debt in 2020 In 20 8, IPL issued $500 million of 4 % senior debentures (green bonds) due September 2028 In 20 8, AEF entered into a $300 million variable rate term loan credit agreement due April 2020 In 20 8, AEF issued $400 million of 3 75% senior notes due June 2023 and $300 million of 4 25% senior notes due June 2028, and a portion of the proceeds from the issuances were used by AEF to retire its $500 million and $95 million variable rate term loan credit agreements expiring in 20 8 In addition, IPL retired $250 million of 7 25% senior debentures and $ 00 million of 5 875% senior debentures in 20 8

Impact of Credit Ratings on Liquidity and Collateral Obligations -

Ratings Triggers - The long term debt of Alliant Energy and its subsidiaries is not subject to any repayment requirements as a result of explicit credit rating downgrades or so called "ratings triggers " However, Alliant Energy and its subsidiaries are parties to various agreements that contain provisions dependent on credit ratings In the event of a significant downgrade, Alliant Energy or its subsidiaries may need to provide credit support, such as letters of credit or cash collateral equal to the amount of any exposure, or may need to unwind contracts or pay underlying obligations In the event of a significant downgrade, management believes Alliant Energy, IPL and WPL have sufficient liquidity to cover counterparty credit support or collateral requirements under these various agreements In addition, a downgrade in the credit ratings of Alliant Energy, IPL or WPL, could also result in them paying higher interest rates in future financings, reduce flexibility with future financing plans, reduce their pool of potential lenders, increase their borrowing costs under existing credit facilities or limit their access to the commercial paper market Credit ratings and outlooks as of the date of this report are as follows:

		S anda d & Poo 's Ra ngs Se v ces	Moody's Inves o s Se v ce
Alliant Energy:	Corporate/issuer	A	Baa2
	Commercial paper	A 2	P 2
	Senior unsecured long term debt	N/A	N/A
	Outlook	Stable	Stable
IPL:	Corporate/issuer	A	Baa
	Commercial paper	A 2	P 2
	Senior unsecured long term debt	A	Baa
	Preferred stock	BBB	Baa3
	Outlook	Stable	Stable
WPL:	Corporate/issuer	A	A3
	Commercial paper	A	P 2
	Senior unsecured long term debt	A	A3
	Outlook	Stable	Stable

Standard & Poor's Ratings Services and Moody's Investors Service issued credit ratings of BBB and Baa2, respectively, for the senior notes issued by AEF in 20 8 (with Alliant Energy as guarantor) Credit ratings are not recommendations to buy or sell securities and are subject to change, and each rating should be evaluated independently of any other rating Each of Alliant Energy, IPL or WPL assumes no obligation to update their respective credit ratings Refer to Note 5 for additional information on ratings triggers for commodity contracts accounted for as derivatives

Off-Balance Sheet Arrangements -

Special Purpose Entities - IPL maintains a Receivables Agreement whereby it may sell its customer accounts receivables, unbilled revenues and certain other accounts receivables to a third party through wholly owned and consolidated special purpose entities The purchase commitment from the third party to which IPL sells its receivables expires in March 202 In 20 9 and 20 8, IPL evaluated the third party that purchases IPL's receivable assets under the Receivables Agreement and believes that the third party is a VIE However, IPL concluded consolidation of the third party was not required

In addition, IPL's sales of accounts receivable program agreement contains a cross default provision that is triggered if IPL or Alliant Energy incurs an event of default on debt totaling $ 00 million or more If an event of default under IPL's sales of accounts receivable program agreement occurs, then the counterparty could terminate such agreement Refer to Note 5(b) for additional information regarding IPL's sales of accounts receivable program

Guarantees and Indemnifications - At December 3 , 20 9, various guarantees and indemnifications are outstanding related to Alliant Energy's cash equity ownership interest in a non utility wind farm and Alliant Energy's and IPL's prior divestiture activities Refer to Note 7(d) for additional information