SIERRA CLUB

May 15, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem, OR 97301

Re: Docket No. UE 375-Opening Testimony and Exhibits of Ed Burgess

Enclosed please find the Opening Testimony and Exhibits of Ed Burgesss on Behalf of Sierra Club in Docket No. UE 375. 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, dba PACIFIC POWER, 2019 Integrated Resource Plan	Docket LC 70

CERTIFICATE OF SERVICE

I hereby certify that on this 15th day of May, 2020, I have served the foregoing Opening Testimony and Exhibits of Ed Burgess 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
Ajay Kumar (C)(HC)
825 NE Multnomah St. Ste. 800
Portland ,OR 97232
ajay.kumar@pacificorp.com
oregondockets@pacificorp.com

STAFF
Scott Gibbens (C) (HC)
Public Utility Commission Of Oregon
201 High St. SE
Salem, OR 97301
scott.gibbens@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

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

OREGON CITIZENS UTILITY BOARD
Bob Jenks (C) (HC)
Michael Goetz (C) (HC)
610 SW Broadway, Ste. 400
Portland, OR 97205
bob@oregoncub.org
mike@oregoncub.org
dockets@oregoncub.org

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

Greg Bass
Calpine Energy Solutions, LLC
401 West A St., Ste. 500
San Diego, CA 92101
greg.bass@calpinesolutions.com

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

NIPPC
Carl Fink
Blue Planet Energy Law LLC
628 SW Chestnut St., Ste. 200
Portland, OR 97219
cmfink@blueplanetlaw.com

Spencer Gray
NIPPC
P.O. Box 504
Mercer Island, WA. 98604
sgray@nippc.org

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

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

Dated this 15th day of May, 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

Case: UE 375

Exhibit Number: Sierra Club/100

Witness: Ed Burgess

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP, dba PACIFIC POWER, 2021 Transition Adjustment Mechanism	Docket UE 375

Opening Testimony of Ed Burgess

On Behalf of

Sierra Club

Public Version

May 15, 2020

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1. **Summary of Findings and Recommendations**

A. My testimony examines the fuel expenditures PacifiCorp requests to recover through its 2021 Transition Adjustment Mechanism ("TAM"). I describe several reasons why the Company's coal fuel expenditures are leading to higher ratepayer costs than necessary, as well as distorted business practices for plant operation, contracting, and wholesale market transactions. I also provide recommendations that could reduce costs.

Q. Please provide a summary of your findings.

A. My findings can be summarized as follows:

1. Some of the inputs included in the GRID model used to calculate PacifiCorp's Net Power Costs ("NPC") (the primary input to the TAM) are leading to an excessive amount of coal dispatch.
2. By understating the cost to dispatch coal, coal plants are excessively run, thus displacing lower cost resources at the expense of ratepayers while PacifiCorp is made whole through the TAM. In fact, some of the most expensive coal on PacifiCorp's system (e.g. [redacted]) is modeled as some of the cheapest.
3. The "costing tier" used to calculate the NPC for coal plants includes a large amount of "fixed" fuel costs that are not included in GRID dispatch decisions or PacifiCorp's wholesale market bid prices.
4. As a result of the discrepancies between PacifiCorp's assessed cost of coal dispatch (the "dispatch tier") and the actual full production cost (the "costing tier") at some coal plants, PacifiCorp regularly incurs higher costs to operate some coal plants than necessary, crowding out lower cost resources, and resulting in excessive costs for ratepayers.

5. The primary discrepancy between the dispatch costs and actual costs (i.e. costing tiers) at some coal plants is attributed by PacifiCorp to the minimum tonnage provisions in PacifiCorp's coal supply agreements, raising a question of if these coal contracts are in the best interests of PacifiCorp's customers. Moreover, the actual GRID model cost inputs are inconsistent with PacifiCorp's own description of its methodology for deriving those cost inputs.
6. In addition to minimum tonnage, PacifiCorp applies other arbitrary modeling constraints such as "must-run" and "minimum burn" limits at most of its coal plants that further distort coal dispatch in the GRID model. In some cases, PacifiCorp also incorrectly bases its dispatch pricing on a small quantity of "supplemental" coal that is not reflective of the overall supply being dispatched.
7. PacifiCorp's business planning activities, including the process of establishing new coal supply agreements, suffer from the same deficiencies as the NPC calculation, leading to suboptimal contract provisions being executed by PacifiCorp on behalf of its customers.
8. PacifiCorp's sales for resale are often made at prices lower than the production costs at its coal plants, even when these plants are running. The availability of TAM recovery thus may be "subsidizing" PacifiCorp's wholesale market transactions, while artificially depressing wholesale market prices. This also gives PacifiCorp an unfair advantage versus other competitive suppliers.
9. Similarly, PacifiCorp produces power from its most expensive coal units when lower cost resources are available. The TAM diminishes PacifiCorp's incentive to alter this practice.

10. The coal dispatch modeled in the TAM is inconsistent with the recent analysis performed by PacifiCorp in its Integrated Resource Plan ("IRP"). Thus the real-world operations of PacifiCorp's fleet do not appear to be aligned with the expectations and decisions made by participants in PacifiCorp's planning process.

Q. Please provide a summary of your recommendations.

A. My recommendations for the 2021 TAM are that the Commission:

1. Correct for uneconomic generation at PacifiCorp's plants using coal fuel not subject to minimum take obligations (or equivalent scenario), including [redacted]. This can be done by removing the projected coal expenses at these plants from the NPC and replacing them with a benchmark fuel cost.
2. Disallow "fixed" fuel costs from being recovered through the TAM if they are associated with contract provisions executed within the last 3 years. This includes relevant minimum tonnage costs for coal supply agreements included in TAM at Jim Bridger (Black Butte supply) and Colstrip.
3. Based on the previous recommendations, adjust the 2021 NPC accordingly, which would result in about $[redacted] total reduction (or approximately [redacted] for Oregon's portion).

My recommendations for future TAM oversight are that the Commission:

1. Require PacifiCorp to update its modeling approach for estimating future NPC as follows:

- When simulating dispatch decisions, use fuel costs that accurately reflect the total production cost paid by PacifiCorp customers, (i.e. the costing tier input values) rather than the subsidized dispatch tier input values. These total production costs should also not be distorted by any small "supplemental" fuel supply.
- Remove all "must run" constraints at any coal plant for the entire model year.
- Remove all "minimum burn" constraints at any coal plant for the entire model year.

2. Direct PacifiCorp to include for review in the Integrated Resource Plan ("IRP") process any new, modified, or updated coal supply agreements with minimum tonnage requirements if PacifiCorp intends to seek cost recovery from Oregon ratepayers.
3. Direct PacifiCorp to provide information to the Commission about the key provisions (including minimum take quantities) of any new, modified, or updated coal supply agreements within 30 days of executing the agreement.
4. Direct PacifiCorp, when requesting any rate changes that include fuel cost recovery, to include for prudence review any new, modified, or updated coal supply agreements with minimum tonnage requirements for which PacifiCorp seeks cost recovery from Oregon ratepayers. PacifiCorp should also be required to provide a detailed explanation for any minimum tonnage provisions included in such agreements
5. Direct PacifiCorp to review its coal contracts with renegotiation provisions and provide the Commission with a report analyzing whether such renegotiations would reduce overall costs for Oregon ratepayers.

6. Provide guidance on PacifiCorp's wholesale market practices, including direction that, if the Company seeks to recover any TAM costs that include an off-system sales component, then the company must report the following information for each hour of the sales period: market bid price ($/MWh), generation units in operation, generation unit production costs ($/MWh), total sales revenue ($), and total energy delivered (MWh). The Commission should then only allow PacifiCorp to recover fuel-related costs for generation during these hours if the market bid price was greater than or approximately equal to the production cost of the highest-cost unit.

2. Introduction

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

A. My name is Ed Burgess. I am a Senior Director at Strategen Consulting. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

Q. Please summarize your professional and educational background.

A. I am a leader on Strategen's consulting team and oversee much of the firm's utility-focused practice for governmental clients, non-governmental organizations, and trade associations. Strategen's team is globally recognized for its expertise in the electric power sector on issues relating to resource planning, transmission planning, renewable energy, energy storage, utility rate design and program design, and utility business models and strategy. During my time at Strategen, I have managed or supported projects for numerous client engagements related to these issues. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and regularly appeared before the Arizona Corporation Commission. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation

Council. I have a Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from Arizona State. I also have a Bachelor of Art degree in Chemistry from Princeton University. A full resume is attached in Exhibit Sierra Club/101.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Sierra Club.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

1. Provide an analysis of PacifiCorp's Transition Adjustment Clause;
2. Describe how PacifiCorp incorrectly models coal generation and related costs;
3. Examine PacifiCorp's practices regarding its coal supply agreements;
4. Assess PacifiCorp's wholesale market transactions and the role TAM plays in those;
5. Explain how these practices ultimately impact costs to PacifiCorp customers; and,
6. Provide recommendations for improving the 2021 TAM and future TAMs.

Q. Have you ever testified before this Commission?

A. No. However, I attended and my firm participated in a workshop before this Commission on the topic of energy storage technologies in May 2016 (Docket No. UM 1751).

Q. Are you generally familiar with electric utilities, and related policy and regulatory issues around the Western U.S.?

A. Yes. I have participated in a variety of activities, projects, and policy forums related to the power system in the West. To provide a few recent examples, I have conducted multiple research projects for the Western Interstate Energy Board. I have participated in technical stakeholder processes at the Western Electricity Coordinating Council and WestConnect. I helped the State of Arizona complete a technical assessment (including power system modeling) of U.S. EPA's Clean Power Plan. I have also engaged in several resource planning and grid modeling activities in Arizona, Nevada, and Colorado. For a recent client project, I conducted a detailed review and comparison of PacifiCorp's retail rate components across its six jurisdictions.

Q. Are you familiar with PacifiCorp's Net Power Cost methodology and dispatch practices?

A. Yes. In addition to reviewing PacifiCorp's TAM application in this proceeding, I previously testified before the California Public Utilities Commission on behalf of the Sierra Club for Docket No. A.19-08-002. In that proceeding, PacifiCorp submitted its Energy Cost Adjustment Clause ("ECAC") to the California Commission. Similar to the TAM, the ECAC is a rate adjustment which PacifiCorp typically files each year to recover costs primarily related to the fuel and purchased power costs associated with power generated or procured to serve its customers. Through that proceeding, I analyzed and provided testimony on PacifiCorp's Net Power Cost methodology and dispatch practices.

Q. Have you ever testified before any other state regulatory body?

A. Yes. In addition to testifying before the California Public Utilities Commission in Docket No. A.19-08-002. I have testified before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General's Office ("AGO") at the evidentiary hearings for D.P.U. 18-150 and D.P.U. 17-140. I have also supported the AGO as a technical consultant in other recent cases including D.P.U. 17-05, D.P.U. 17-13, D.P.U. 15-155, and D.P.U. 17-146. I have also testified before the South Carolina Public Service Commission on behalf of the South Carolina Solar Business Alliance in evidentiary hearings for 2019-186-E, 2019-185-E, and 2019-184-E. Additionally, I have represented numerous clients by drafting written testimony, drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at state Public Utilities Commissions including Arizona, California, New Hampshire, Nevada, Oregon, Pennsylvania, North Carolina, Maryland, District of Columbia, New York, Minnesota, Ohio, at the Federal Energy Regulatory Commission, and at the California Independent System Operator.

Q. How is your testimony organized?

A. My testimony is organized into the following six sections. First, I provide an overview of the key features of PacifiCorp's Transition Adjustment Mechanism, including the Net Power Cost calculation. Second, I describe PacifiCorp's coal supply. Third, I provide an assessment of why PacifiCorp's modeling overestimates coal generation. Fourth, I explain how the same modeling errors impact PacifiCorp's business practices for plant operation and fuel contracting. Fifth, I explain the connection between the TAM and PacifiCorp's participation in wholesale markets. Fifth, I offer a summary of important emerging policy issues in this case, and finally, I offer some recommendations for how to improve the TAM in this proceeding and going forward.

3. <u>The Transition Adjustment Mechanism and PacifiCorp's 2021 TAM Application</u>

A. Overview of the Transition Adjustment Mechanism

Q. What is the purpose of the Transition Adjustment Mechanism?

A. The Transition Adjustment Mechanism ("TAM") is a rate adjustment that PacifiCorp files annually to update its forecasted Net Power Cost ("NPC") calculation. The NPC is in turn used to determine the power supply rates for customers who have elected to take cost-based supply service (e.g. under Rate Schedule 201). These rates recover costs primarily related to the fuel and purchased power costs associated with power generated or procured to serve PacifiCorp's customers.

Q. Does the TAM include a mechanism to true up any discrepancies between the actual NPC and forecasted NPC fuel and power purchase costs?

A. No. The TAM only includes the forward-looking fuel cost component. A separate adjustor, the Power Cost Adjustment Mechanism ("PCAM"), is used to "true up" the actual dollar-for-dollar fuel expenditures that have occurred in both the current and prior year. In its concurrent General Rate Case (Docket No. UE 374) PacifiCorp has proposed to consolidate the TAM and PCAM proceedings in the future.

Q. In your opinion, is it typical to review the economics of commitment and dispatch decisions within fuel adjustment clause proceedings?

A. No, many fuel adjustment clauses like the TAM are approved annually by state utility regulatory commissions on a somewhat routine basis and without much scrutiny. In some states, the review of fuel adjustment clauses is carried out on a pro forma basis. This is true despite the fact that fuel costs comprise a significant overall portion of customer rates. In PacifiCorp's case fuel costs are on the order of $0.02-0.025/kWh, or roughly 20-

25% of standard residential energy rates.[1] Given the impact on captive customers' bills, proceedings like this one are very important for customers. In Oregon's case, the TAM appears to receive substantial review by the Commission and stakeholders, however this review does not focus on issues surrounding coal supply agreements and coal plant dispatch which are the focus of my testimony.

Q. Is there reason to think that fuel dockets and issues such as economic commitment and dispatch are issues that warrant deeper scrutiny than has been typically received?

A. Yes. Recent research from several organizations including Sierra Club and the Union of Concerned Scientists have shown that rate-regulated utilities operating in wholesale energy markets tend to commit and dispatch coal units out of economic merit, incurring costs above energy market costs.[2] The most recent of these assessments was completed by the Market Monitoring Unit ("MMU") of the Southwest Power Pool ("SPP"), which found that if coal units did not elect to self-commit, they would reduce production costs by ½ percent.[3] Sierra Club's assessment was conducted for the year 2017, while SPP's assessment was conducted for 2018/2019. In the interim period, market prices have fallen substantially due to stagnant demand, low gas prices, and increasing renewable energy,

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[1] Assuming $0.10/kWh for baseline PacifiCorp's residential energy charges.

[2] Jeremy Fisher et al., *Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets*, Sierra Club (Oct. 2019), *available at* https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf [hereinafter "Playing With Other People's Money (Fisher)"] (attached as Exhibit Sierra Club/102); *see also* Maya Weber, *Non-profit study sees 'self-committed coal' distorting MISO market signals*, S&P Global (Nov. 20, 2019), *available at* https://www.spglobal.com/platts/en/market-insights/latest-news/coal/112019-non-profit-study-sees-self-committed-coal-distorting-miso-market-signals

[3] Southwest Power Pool, *Self-committing in SPP markets: Overview, impacts, and recommendations* at 39(Dec. 2019), *available at* https://assets.documentcloud.org/documents/6573451/Spp-Mmu-Self-Commitment-Whitepaper.pdf [hereinafter "Self-committing in SPP markets"] (attached as Exhibit Sierra Club/103).

meaning that coal plants operating in late 2019, and projected to operate in 2020 and beyond are at risk of operating well above the prevailing cost of alternatives – whether market-based or other lower cost generation resources.

While PacifiCorp does not operate in precisely the same type of day-ahead wholesale market as SPP or Midcontinent Independent System Operator ("MISO"), the issues here are similar in nature.[4] I contend specifically that by using a lower cost for dispatch than is actually realized for the purposes of production, PacifiCorp is incurring costs above the costs of alternative generation or market options. In many cases, including here in Oregon, the only mechanism in which these costs and the Company's election to operate can be assessed are through fuel dockets.

Q. Have you reviewed PacifiCorp's testimony and supporting workpapers in this proceeding regarding the calculation of the 2021 TAM?

A. Yes. I reviewed the core components of the TAM as described above. As explained, the primary component of the 2021 TAM is PacifiCorp's forecasted NPC for the year 2021, a portion of which (~25%) is allocated to Oregon.

[4] Sierra Club/103. Self-committing in SPP markets .

B. PacifiCorp's 2021 TAM Application and Net Power Cost Calculation

Q. Please provide a brief overview of PacifiCorp's application for approval of its 2021 TAM.

A. On February 14, 2020, PacifiCorp submitted an application to this Commission requesting authorization to update certain components of its TAM for 2021. These components include 2021 NPC, NPC adjustments, Production Tax Credits, as well as transmission credits for direct access customers.

Q. Can you further describe the core component of the TAM – namely the amount of NPC to be included in customer rates?

A. Yes. In TAM, the NPC is the calculation of projected power costs collected in rates and is based on a forecast of PacifiCorp's fuel expenses, wholesale purchase power expenses, and wheeling expenses less wholesale sales revenue for the coming year. It is forward looking and intended to proactively recover PacifiCorp's expected future fuel costs as they occur.

Q. What are the total-company NPC in the TAM for calendar year 2021 (prior to adjustments and tax credits)?

A. The forecasted total-company NPC for calendar year 2021 are $1.4 billion. Approximately 25% of the forecasted NPC, or $356 million, is allocated to Oregon.[5]

Q. What adjustments are made to NPC for the purpose of the setting the 2021 TAM power supply rates?

A. The largest adjustment is the subtraction of Production Tax Credits ("PTC"), which totals $64.6 million for 2021. Thus, the Oregon-allocated revenue requirement targeted for rate

[5] PAC/101 at Webb/1.

recovery through the TAM is approximately $292 million (i.e. $356.6 million less $64.6 million).[6]

Q. Please provide a brief overview of what costs are included in the NPC.

A. NPC represents the power costs of meeting PacifiCorp's total generation requirements (including both retail load and sales for resale). More specifically, NPC is defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

Q. Can you summarize the underlying components of the NPC in TAM 2021?

A. Yes. The main components of the total NPC are summarized in the following table, based on Exhibit PAC/101:

Table 1: 2021 NPC Components

		Total Company		Oregon Allocated
Sales for Resale	$	(281,620,789)	$	(73,285,143)
Purchased Power	$	612,513,738	$	159,253,600
Wheeling Expense	$	139,073,187	$	36,165,687
Fuel Expense	$	930,924,285	$	233,675,847
Net Power Cost (Per GRID)	$	1,400,890,421	$	355,809,991
Oregon Situs NPC Adjustments	$	786,770	$	786,770
Total NPC	$	1,401,677,191	$	356,596,762

Of the $931 million of fuel expenses, 66%, or $613 million, are coal fuel expenses. Thus, nearly half of the NPC is comprised of costs for burning coal. Consequently, Oregon ratepayers pay approximately 10% of standard residential energy rates on coal fuel.

[6] PAC/101 at Webb/1.

Q. Do these recoverable costs include all of the anticipated costs to continue operating these coal plants?

A. No. There are other ongoing costs associated with those plants that are not recovered through the TAM, such as variable and fixed operations and maintenance costs. Additional ongoing costs may be recovered as capital expenditures. For example, PacifiCorp owns the Bridger and the Trapper Coal Mines, and my understanding is that these costs would be included in the Company's rate base rather than the fuel cost recovered through the TAM.

Q. How does PacifiCorp estimate its future Net Power Costs for purposes of calculating the 2021 TAM?

A. According to Mr. Webb's testimony, PacifiCorp uses its Generation and Regulation Initiative Decision Tool ("GRID"), which is a production cost model, to simulate the operation of the company's power system on an hourly basis. This provides an estimate of the projected amount of generation that will occur at each of PacifiCorp's generation units, as well as purchased power, to serve its own load and for off-system sales

Q. What is PacifiCorp's objective when simulating system operations?

A. According to Mr. Wilding, "The Company's goal in determining optimal dispatch and forecasting NPC is to minimize power costs holistically over the forecast period."[7] GRID

[7] Ex. PAC/800, Rebuttal Testimony of Michael G. Wilding [Confidential Version], *In the Matter of the Application of PacifiCorp (U901E) for Approval of its 2020 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue*, Docket No. A.19-08-002 at 10 (Cal. Pub. Util. Comm'n Feb. 19, 2020) [hereinafter "ECAC Wilding Rebuttal"] (provided as an attachment to PacifiCorp's Response to Sierra Club Data Request 2.1) (attached as Exhibit Sierra Club/104).

optimizes the dispatch of the "company's existing system in the most economic manner while accounting for system constraints."[8]

C. Cost of Coal Fuel Included in the 2021 TAM

Q. Can you provide a breakdown of the coal fuel burn expenses that are included in the 2021 NPC Projections?

A. Yes. As reflected in Workpaper ORTAM21 NPC CONF, the anticipated 2021 coal fuel burn expenses can be broken down by plant as follows:

Table 2: Unit Average Cost based on 2021 projected NPC and generation[9]

Plant	2021 Projected Coal Burn Expenses ($)[10]	2021 Projected Generation (MWh)	Average Cost ($/MWh)
Colstrip	$16,438,683	[redacted]	[redacted]
Craig	$17,499,897	[redacted]	[redacted]
Dave Johnston	$48,459,229	[redacted]	[redacted]
Hayden	$14,769,365	[redacted]	[redacted]
Hunter	$108,641,852	[redacted]	[redacted]
Huntington	$94,054,145	[redacted]	[redacted]
Jim Bridger	$205,967,584	[redacted]	[redacted]
Naughton	$78,436,167	[redacted]	[redacted]
Wyodak	$28,470,445	[redacted]	[redacted]
Total Coal	$612,737,366	[redacted]	[redacted]

Q. How do the TAM 2020 coal generation and fuel expenses compare to TAM 2021?

A. In TAM 2021, coal generation was reduced by [redacted], while coal expenses fell only by 11%,[11] due to higher coal prices. Despite higher coal prices, total NPC over net system

[8] PacifiCorp Response to Sierra Club Data Request 1.4(a). All public discovery responses referenced in this testimony are compiled and attached as Exhibit Sierra Club/105.
[9] 2021 projected generation and average cost do not include operations at the Cholla plant. PacifiCorp owns Cholla Unit 4, and has announced plans to retire this unit by the end of 2020.
[10] PAC/102 at Webb/5.
[11] PAC/300 at Ralston/5:4-Ralston/6:1.

load fell by 4%[12] due to the displacement of coal generation by significantly lower cost renewable resources.[13] Still, after reviewing TAM 2021, it is my conclusion that coal generation remains inefficiently high resulting in unnecessary costs for ratepayers.

Q. Please summarize your observations around the coal units' fuel costs.

A. There is a significant range in coal fuel burn related costs projected for 2021 which PacifiCorp intends to recover, in part, through the TAM. On average, the NPC for all of PacifiCorp's coal plants is expected to be [redacted]; however, for some plants the cost is much higher. For example, the Jim Bridger and Naughton plants have projected coal fuel burn expenses of [redacted] and [redacted], respectively. This is not only significantly higher than other coal units, it is also higher than the average 2021 NPC costs for <u>all</u> generation sources, which is [redacted].

Q. Please explain why it is problematic that these specific units have high fuel costs?

A. There are two reasons for concern. First, lower cost resources are readily available that could be used in their place. Second, not only do these units have high fuel costs but they also have high capacity factors compared to other coal units, which is counterintuitive and illustrates that they are being operated uneconomically and in a manner that is not in the best interests of PacifiCorp ratepayers. I explain both below.

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[12] PAC/100 at Webb/7, Figure 1.
[13] TAM 2021 based on the confidential workpaper to the Direct Testimony David Webb on Behalf of PacifiCorp, "ORTAM21 NPC CONF.xlsm,tab NPC [hereinafter "ORTAM21 NPC CONF (Webb)"].
TAM 2020 based on the confidential work paper to the Direct Testimony of David Webb on Behalf of PacifiCorp, "ORTAM21 Testimony Support CONF.xlsx", tab ORTAM20 [hereinafter "ORTAM21 Testimony Support CONF (Webb)"].

Q. How do those plants' projected coal burn expenses compare to potential alternatives?

On a simple $/MWh basis, the average coal burn expenses of the Jim Bridger, Naughton, and Hayden plants, among others, are significantly higher than the costs of alternatives including: other PacifiCorp-owned coal plants, PacifiCorp-owned gas plants, short-term firm purchases, and new (2020 installation) renewable energy resources. The table below provides a cost comparison of these different resources.

Table 3: 2021 Average Cost of Coal Units and Alternatives

Resource	Average Cost ($/MWh)	Source
Naughton Coal Plant	[redacted]	2021 NPC Projection, Workpaper ORTAM21 NPC CONF
Jim Bridger Coal Plant		2021 NPC Projection, Workpaper ORTAM21 NPC CONF
Hayden Coal Plant		2021 NPC Projection, Workpaper ORTAM21 NPC CONF
PacifiCorp Gas Fleet Average		2021 NPC Projection, Workpaper ORTAM21 NPC CONF
3.6 MW Wind Turbine 43.6% CF WY, 2020 (100% PTC)	$17.08	2019 PacifiCorp IRP Projection

Q. Could PacifiCorp replace a substantial amount of these units' generation with Wyoming wind and market purchases?

A. Yes. Given the low costs of wind combined with the competitive price of wholesale market energy, PacifiCorp could displace a substantial amount of the energy generated from higher-cost coal-fired units with lower-cost resources. While the energy produced from a single wind power source may not perfectly match the output from a single coal source on a one to one basis during each hour, a diverse portfolio of wind resources can still replace a substantial amount of the coal PacifiCorp expects to generate.

Q. What are the potential cost savings to its customers if PacifiCorp pursued these lower-cost alternatives instead?

A. If PacifiCorp replaced a portion of the generation from its coal units with lower cost available resources, ratepayers would enjoy significant benefits. For example, if the forecasted generation from Jim Bridger and Hayden was reduced to a level where they simply consumed their minimum take contract quantities, but no more, and the rest was replaced with wind , this would result in net NPC savings of $[redacted] (assuming wind resource costs equal to those in PacifiCorp's 2019 IRP). These estimates do not include additional savings from reduced non-fuel operating and maintenance costs at these plants. Absent the minimum take contract provisions present in current coal supply agreements for these plants, these savings could be on the order of [redacted]

Q. How would ratepayers benefit from these hypothetical savings?

A. If the amount of coal generation projected for the 2021 NPC was lower than PacifiCorp's present proposal, and was instead replaced with lower-cost resources, then this would result in a reduced NPC revenue requirement for the 2021 TAM. This would in turn lead to a lower set of rates established in Schedule 201 for cost-based supply service. As long as PacifiCorp operated its system so that the actual 2021 NPC costs were indeed similar to this revised forecast, then the PCAM adjustment would be minimal and ratepayers would retain these savings.

Q. Could ratepayers enjoy the same benefits through the PCAM adjustment if this substitution occurred after the 2021 TAM NPC forecast was set?

A. Only to a limited degree. The PCAM adjustment is subject to several constraints, including a dead band and shared savings mechanism, that would limit the amount of savings that are conferred to ratepayers if PacifiCorp achieved a lower cost option. This illustrates the importance of ensuring that the initial NPC forecast, its underlying modeling assumptions, and related business decisions are all appropriate at the front end of the TAM/PCAM cycle.

Q. Does PacifiCorp have an incentive to pursue these potential NPC reductions in advance on behalf of its customers?

A. Not necessarily. While a possible reduction in the TAM would serve to provide this benefit to customers, the incentive for PacifiCorp to pursue lower cost options is reduced since the savings are largely returned to customers rather than retained by the company's shareholders. This lack of an incentive for PacifiCorp to identify the lowest-possible energy cost in its initial NPC forecast is a major reason why additional Commission oversight over the TAM is important.

Q. Isn't PacifiCorp already retiring some coal generation and replacing it with wind power?

A. Yes; however, a review of PacifiCorp's fleet and dispatch indicates that this is happening relatively slowly and that the system will still be operated inefficiently for a foreseeable period. As part of the Energy Vision 2020 initiative, PacifiCorp has repowered most of its wind generation facilities and is also building 1,150 MW of new wind generation.[14] PacifiCorp is thus beginning to act upon the recognition that savings that can be achieved by transitioning to lower cost energy sources such as wind. However, it appears that additional savings would be possible from an even more ambitious transition. The Coal Studies conducted by PacifiCorp and attached as Appendix R in its Integrated Resource

[14] PAC/100 at Webb/8:3-5.

Plan show that early retirement of almost all of the Company's coal units would be beneficial to ratepayers.[15] My review of the TAM shows that PacifiCorp's coal fleet is not only uneconomic in a long-term planning context, but it is also being operated inefficiently in the near-term resulting in higher costs for ratepayers than necessary.

Q. In addition to costs, have you examined the plants' forecasted capacity factors?

A. Yes.

Q. Why is it important to examine the plant's costs in parallel with their forecasted capacity factors?

A. Examining the units' costs in parallel with their forecasted capacity factors can show where specific plants may be operating uneconomically. Under normal system conditions, one would expect a generation fleet using economic dispatch to operate in merit order, with the most expensive units running least often (i.e. having lower capacity factors) and the least expensive units running most often (i.e. having higher capacity factors). Table 4 below reveals that the forecasted operations of PacifiCorp's coal fleet significantly contradict the merit order.[16]

[15] PacifiCorp, 2019 Integrated Resource Plan, Volume II at Appendix R (Oct. 18, 2019), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html. (attached as Exhibit Sierra Club/106).
[16] ORTAM21 NPC CONF (Webb), tabs NPC and GRID Nameplate (MW).

Table 4: TAM 2021 Average Cost and Projected Capacity Factor by Plant (ranked in order of increasing capacity factor)

	TAM 2021 Average Cost ($/MWh)	TAM 2021 Capacity Factor (%)
[redacted]		

Under certain conditions units might have to operate out of the merit order due to technical or reliability constraints; however, this should not be the case under most circumstances. As shown above, PacifiCorp's coal units operate significantly out of the merit order. For example, the [redacted] plant has the highest projected average cost of any plant in PacifiCorp's coal fleet [redacted], while also having one of the highest capacity factors [redacted], which is the opposite of what would normally be expected. Similarly, [redacted] has the highest capacity factor [redacted], while at the same time its costs are above average ([redacted] compared to an average of [redacted] for the coal fleet).

Q. Why is the projected generation from some coal plants high despite lower-cost alternatives?

A. As I will explain later in my testimony, it is my opinion that there are modeling assumptions in the NPC calculation that PacifiCorp performed which lead to an overestimate of the level of generation that is economic at some coal plants. Additionally, there are multiple aspects of PacifiCorp's coal supply agreements and coordination with co-owners that artificially limit PacifiCorp's dispatch options and further inflate the amount of projected coal generation. If these problems were corrected, the analysis would accurately reflect the true costs associated with these coal units, which could reduce their dispatch, thus allowing less costly alternative resources to be used instead. This in turn would yield savings to PacifiCorp's customers through reduced NPC forecasts and associated TAM rates going forward.

Q. Do you have any recommendations to ensure that PacifiCorp customers can realize these savings in this and future TAM proceedings?

A. Yes. I have provided my recommendations in Section 9 of my testimony below.

Q. Would these savings be realized in PacifiCorp's actual operations?

A. Yes. The same problems that I have identified in PacifiCorp's NPC modeling also apply in PacifiCorp's actual operations. If these were corrected, Oregon ratepayers could realize significant benefits.

4. <u>PacifiCorp's Coal Supply Agreements Are Major Drivers of Fuel Costs in the 2021 TAM</u>

Q. Have you reviewed all of PacifiCorp's current coal supply agreements?

A. Yes. I have provided a summary table of the key provisions of these agreements, as well as associated GRID modeling parameters as Exhibit Sierra Club/108, which is attached to my testimony.

Q. You testified earlier that one factor inflating PacifiCorp's forecasted coal generation is its coal supply agreements. Can you summarize PacifiCorp's coal supply and transportation agreements currently in effect for 2021?

A. Yes. The coal supply and transportation contracts currently in effect for 2021 per plant are:[17]

Table 5: CSAs currently in effect for 2021

PLANT	MINE	TYPE	TERM END	MINIMUM TONS
COLSTRIP	[redacted]			
CRAIG				
DAVE JOHNSTON				
HAYDEN				
HUNTINGTON				
JIM BRIDGER				
NAUGHTON				
WYODAK				

Coal prices in PacifiCorp's Coal Supply Agreements ("CSA") range from less than [redacted] to more than [redacted]

[17] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.6 (attached as Exhibit Sierra Club/107)

[18] *Id.* ("Due to grandfathered Castle Valley agreement - the contract minimum is effectively [redacted] through 12/31/2020.").

[19] Minimum tons updated based on Commission Workshop on coal fueling (May 12, 2020). Sierra Club/107, Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.6. had Wyodak minimum tons equal to [redacted] million tons.

[redacted] Exhibit Sierra Club/108 provides additional information on PacifiCorp's CSAs.

Q. Please explain the categorization of contracts to take-or-pay and liquidated damages.

A. Under a take-or-pay agreement, PacifiCorp has agreed to take a minimum amount of coal. In the event that PacifiCorp does not take the full amount, it is still required to pay for it. Take-or-pay CSAs can have a single price for the entire amount or specify different pricing tiers for portions of that amount. Additionally, some of PacifiCorp's coal plants have transportation agreements that include "liquidated damages." Liquidated damages clauses require PacifiCorp to pay a penalty ("damages") if the Company fails to take the agreed-upon minimum contract volume.

Q. Please explain the significance of take or pay contract provisions.

A. Take or pay provisions with minimum tonnages have a significant impact on how PacifiCorp both models and operates its coal units, which in turn affects its NPC forecast and ultimately its TAM supply rates. The inclusion of these minimum tonnage provisions can significantly limit the Company's willingness or ability to reduce coal generation, even if lower cost options exist, because the Company has already committed to purchasing a minimum amount of coal fuel.

Q. Are any of PacifiCorp's CSAs currently in effect ending in 2020, 2021, or 2022?

A. Yes, below is a table with the contracts that are expiring in 2020-2022.[20]

[20] Sierra Club/107, Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.6.

Table 6: Contracts ending in 2020-2022

Term End	Plant	Mine	Minimum Tons
[redacted]			

Q. Are all of PacifiCorp's plants currently subject to minimum take requirements in the 2021 TAM timeframe?

A. No. As shown in Table 6, some CSAs end in 2020, leaving the plants with open coal positions and no minimum take provisions in place for 2021. Furthermore, Jim Bridger has no contractual minimum tonnage. PacifiCorp's coal supply that is currently not subject to minimum take provisions in 2021 is summarized below:

- Hunter has an open coal position for 2021 and thus no minimum take provision is currently in effect for 2021. PacifiCorp is negotiating a new CSA for the Hunter plant.[21]
- Dave Johnston has an open coal position for 2021 and thus the plant's minimum take volume is based only on its CSAs with Coal Creek and Caballo mines. PacifiCorp expects to request proposals for the 2021 open position of the Dave Johnston plant in the second or third quarter of 2020.[22]

[21] Sierra Club/105, PacifiCorp Response to Staff Data Request 55.
[22] Sierra Club/105, PacifiCorp Response to Staff Data Request 53.

- [redacted].[23] Craig will continue being supplied by the Trapper mine, which is partially owned by PacifiCorp. [redacted].[24]
- Jim Bridger is currently fueled by two providers, Bridger Coal Company (BCC) and Black Butte Coal Company. BCC is a jointly-owned, indirect subsidiary of the Jim Bridger plant owners (PacifiCorp and Idaho Power Company). No minimum take tonnage shortfall payments are assessed by BCC.[25]

Although Huntington's CSA with Castle Valley ends December 31, 2020, the volume that was previously purchased under the Castle Valley contract ([redacted] tons) will come from the Wolverine CSA in 2021. Thus although, [redacted].[26]

Q. **Do PacifiCorp's coal supply agreements have provisions that would allow it to renegotiate the minimum tonnage [redacted]**

A. Yes. There are several provisions to this effect, though to my knowledge these have been seldom exercised. As an example, PacifiCorp's coal supply agreement for the [redacted]t [redacted]

[23] Sierra Club/107, Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.6.
[24] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.7 (attached as Exhibit Sierra Club/109).
[25] PAC/300 at Ralston/3:17-21.
[26] Sierra Club/107, Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.6.

[redacted].[27]

Q. Are you aware of other PacifiCorp coal supply agreements that have provisions that would allow them to be renegotiated?

A. According to SC 1.31, the CSAs in effect in 2021 that include such provisions are: [28]

- Naughton Plant CSA– PacifiCorp & Kemmerer Operations, LLC
  Article 3.1 Environmental Response
- Huntington Plant CSA– PacifiCorp & Wolverine Fuels, LLC
  Article VIII Environmental Regulations
- Colstrip Plant CSA – PacifiCorp & Westmoreland Rosebud Mining, LLC
  Article 8.1 Changes in Applicable Law

PacifiCorp exercised the provision contained in the Naughton Plant CSA in March 2015. This action reduced the minimum volume requirement from [redacted] tons per year to [redacted] tons/year.[29]

For the Huntington and Colstrip contracts, the minimum purchase obligation if PacifiCorp chose to rely on such a provision would be [redacted] [30]

[27] PacifiCorp Response to Sierra Club Highly Confidential Data Request 4.1 (attached as Exhibit Sierra Club/110).
[28] Sierra Club/105, Redacted PacifiCorp Response to Sierra Club Data Request 1.31 (This response also identifies the Hunter CSA to include such a provision. However, the Hunter CSA ends in 2020.).
[29] Confidential PacifiCorp Response to Sierra Club Data Request 1.31(b) (selected confidential data responses are attached as Exhibit Sierra Club/111)
[30] *Id.*at 1.31(a).

5. PacifiCorp's Net Power Cost Methodology Overestimates Coal Dispatch in the 2021 TAM

A. Overview of the GRID Model

Q. How does PacifiCorp estimate its future Net Power Costs for purposes of calculating the 2021 TAM?

A. PacifiCorp uses GRID, which is a production cost model, to optimize the dispatch of the "company's existing system in the most economic manner while accounting for system constraints."[31]

Q. Do you have concerns about how the GRID model estimates plant dispatch?

A. Yes. A production cost model dispatches existing resources to serve the forecasted load in the most economic manner. In principle this is an appropriate way to estimate future fuel and purchased power costs. However, I am concerned that the specific input data and additional modeling constraints chosen by PacifiCorp for use in the GRID model are producing modeling results that significantly deviates from the least cost dispatch. Those inputs and constraints may be leading to excessive projections of coal dispatch, beyond what may be prudent for PacifiCorp's customers. This excess dispatch may also be occurring during actual operations for similar reasons.[32] As such, the GRID model may reasonably reflect how PacifiCorp operates its system. However, this does not mean that the level of coal generation assumed by the model, or realized in actual operations, is either appropriate or reasonable.

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[31] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 1.4.
[32] For example, as detailed in Section 6, most of the bid prices used in PacifiCorp's actual wholesale market transactions are similar to the assumptions included in the GRID model.

The modeling choices that lead to coal overgeneration are:

- Input Data:
  - The selective inclusion of variable operating and maintenance costs
  - The use of very low fuel costs for coal plants
- Model Constraints:
  - The inclusion of must-run constraints (or equivalently, the absence of economic cycling) for coal plants
  - The inclusion of minimum fuel burn constraints for coal plants

I explain my concerns in more detail below and their impact on the amount of coal generation projected in the 2021 NPC.

B. GRID Model Input Data and their Impact on Coal Generation Projected in the 2021 NPC

Q. How might the GRID model inputs lead to excessive generation at a particular resource in the NPC forecast?

A. Since the GRID model is a production cost simulation, it performs a cost-minimization procedure to determine the least-cost set of resources for meeting PacifiCorp's load in each hour of the year. The resulting generator commitment and dispatch decisions are in turn guided by unit-specific inputs for the cost of production such as fuel commodity prices, heat rates, and variable Operation and Maintenance ("O&M") costs. Excessive dispatch could occur if the production cost inputs are set too low for some plants and do not capture the full range of costs that are ultimately paid by PacifiCorp's customers through the TAM/PCAM adjustors.

Q. How could these factors lead to excessive generation at PacifiCorp's coal units in real-world operations?

A. There are a few ways this could occur. First, just as the production cost inputs for specific coal units could be set too low in the GRID model, PacifiCorp could use bid prices that are below the plant's true costs for its wholesale market transactions. Second, PacifiCorp might use the overstated generation forecasts modeled in GRID as a starting point for its business planning activities, including coal contract negotiations that establish minimum tonnages. PacifiCorp then in turn uses these contracted (or anticipated) minimum volumes to guide its operations. This creates a "vicious cycle" in terms of the relationship between the coal contracting process and how plant dispatch is projected.

Q. Have you examined the specific production cost inputs within GRID with these issues in mind?

A. Yes. In particular, I have focused my examination on the inputs for variable O&M costs and fuel costs.

Q. How does the GRID model incorporate variable O&M costs for each generation unit?

A. Variable O&M costs as included in the GRID model can be found in the table below. The table also compares the GRID inputs to those reported by PacifiCorp in its most recent FERC Form 1 filing (sourced from S&P Global Market Intelligence), based on reporting at the plant level.

Table 6: Variable O&M Costs in GRID and FERC Form 1

Coal Generation Unit	GRID Variable O&M Costs Inp ($2021/MWh)[33]	2019 Non-Fuel Variable O&M Costs Per MWh Reported in FERC Form 1 (Sourced from S&P)
Colstrip 3&4	[redacted]	$3.96
Craig 1&2		$3.87
Dave Johnston 1&2 Dave Johnston 3&4		$4.04
Hayden 1&2		$4.25
Hunter 1&2 Hunter 3		$2.81
Huntington 1&2		$3.77
Jim Bridger 1 Jim Bridger 2 Jim Bridger 3 Jim Bridger 4		$0.88
Naughton 1 Naughton 2		$4.33
Wyodak		$3.77

Q. Why is the level of variable O&M relevant in TAM?

A. Even if not recovered in the TAM, the level of variable O&M costs in GRID can have impacts on the final NPC. The inclusion of lower variable O&M artificially deflates the cost of running the coal units relative to other resources in the GRID model and thereby leads to an overestimation of coal generation, the costs of which are recovered in TAM.

[33] 5-Day Confidential Workpaper supporting thePacifiCorp 2021 TAM Application, , "ORTAM21_Fuel Price (1912) CONF.xlsm.", tab VOM [hereinafter " CONF ORTAM21_Fuel Price (1912)"].

Q. How does the GRID model incorporate fuel costs for each generation unit?

A. As described in SC 1.4, GRID utilizes two different price tiers to estimate the NPC of the company's thermal plants; namely the "dispatch tier," and the "costing tier." The GRID model dispatches units using the "dispatch tier," but calculates the NPC using the "costing tier."[34] More specifically, the model attempts to find the fleet's optimal generation to achieve the lowest feasible production cost based on the "dispatch tier." This yields a projection of the optimal generation level for each plant in MWh. However, to calculate the NPC, this generation level is then multiplied by a different fuel price -- the costing tier. Thus, the expected coal generation in TAM is projected based on the generally lower dispatch tier prices, but PacifiCorp seeks to recover costs based on the generally higher costing tier prices. The difference of the two cost levels raises important questions as to whether the costs PacifiCorp seeks to recover through the TAM truly reflect the "least cost" set of resources from its customers' perspective.

Q. Please provide the GRID costing and dispatch tiers for all plants as used for forecasting the 2021 NPC.

A. The table below summarizes the costing and dispatch tiers as used in the GRID model for forecasting the 2021 NPC.[35] The significant difference of the two tiers results in a different merit order for the units than the one that would minimize power costs for Oregon ratepayers. For example, Naughton and Jim Bridger are the two most expensive

[34] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 1.4(a).
[35] ORTAM21_Fuel Price (1912) CONF.xlsm, Tab 4 GRID Coal 2019+; Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 1.10 (a)(iii) ("For coal fuel prices used in Generation and Regulation Initiative Decision Tool (GRID), please refer to the 5- day confidential work paper supporting the direct testimony of David G. Webb, specifically file "ORTAM21_Fuel Price (1912) CONF.xlsm.").

units, but are modelled as if they were some of the least expensive ones. They are thus projected to generate more, and ratepayers have to cover their full cost.

Table 7: GRID 2021 tiers

Coal Plant Name	Grid Costing Tier 2021 ($/MMbtu)	Grid Dispatch Tier 2021 ($/MMbtu)	Difference
Colstrip	[redacted]		
Craig			
Dave Johnston			
Hayden			
Hunter			
Huntington			
Jim Bridger			
Naughton			
Wyodak			

Q. What do you conclude from reviewing the GRID tier levels?

A. I conclude that there is costly distortion in the system. The tiers used to model generation differ greatly from the actual costs recovered from ratepayers. This fact shows how distorted the projected optimal operations in GRID are. PacifiCorp relies on GRID to minimize the costs of operating its units, but its inputs are so distorted that I can confidently conclude that its output is not the system's true least cost dispatch. For [redacted], the dispatch and costing tier do not differ significantly. For [redacted] the dispatch tier is higher than the costing tier. For [redacted] the higher dispatch tier can be partially explained by the fact that these units have transportation contracts with liquidated damages provisions. For [redacted] which according to SC 1.6. does not have any contract with liquidated damages, the higher dispatch cost cannot be explained by the data available. However, most importantly, there are four units whose dispatch is modeled based on a dispatch tier significantly lower than the costing tier. I will focus my review on these four units.

Q. What is PacifiCorp's rationale for using two pricing tiers in the model?

A. According to PacifiCorp's response to SC 1.4:

> (1) The "dispatch tier" costs are the incremental costs to operate PacifiCorp's coal plants. The incremental cost is the change in cost to generate additional generation from each power plant. . .
>
> (2) The "costing tier" is the average annual unit price for fuel expense. The average cost of coal includes all of the cost of coal purchased under existing coal supply agreements or from company mining operations.

Thus, my understanding is that the "costing tier" represents the actual full NPC fuel costs passed on to ratepayers, while the "dispatch tier" reflects a theoretical plant dispatch cost calculated by PacifiCorp for modeling purposes. The difference between the two is ostensibly based on the type of coal supply and transportation agreements that PacifiCorp has signed for each plant.

Q. Does PacifiCorp explain how the dispatch and costing tiers are calculated for a plant with a take-or-pay agreement?

A. Yes. According to PacifiCorp:

> The take-or-pay provisions in PacifiCorp's coal supply agreements (CSA) require the payment for the coal even if it is not delivered or used for generation, therefore the fuel portion of the marginal cost of generation in that price tier is zero. The company does not use the average price as a dispatch price in short-term forecasts because the cost of coal in a take-or-pay volume tier is not avoidable.
>
> For example, suppose a CSA had a provision with a minimum take-or-pay volume of 1,000,000 tons. The incremental price for volumes between zero and 1,000,000 tons would be zero because the take-or-pay volumes are treated as a minimum requirement or sunk cost. Suppose further that the CSA set a price for the first 1,000,000 tons at $2 per million British thermal units ($/MMBtu) and any purchases above 1,000,000 tons were $1/MMBtu. The incremental price above the take-or-pay volume of 1,000,000 tons would be $1/MMBtu. Assume that GRID modeled generation of, and the company

> purchased 2,000,000 tons, the average or "costing tier" price in GRID would be $1.50/MMBtu, and the incremental or 'dispatch tier' price would be $1/MMBtu.[36]

Q. Does PacifiCorp explain how the dispatch and costing tiers are calculated for a plant with a liquidated damages agreement?

A. Yes. According to PacifiCorp:

> Liquidated damages provisions provide for a payment, less than the full price of coal, to be due if PacifiCorp fails to take the minimum contract volume. The company accounts for liquidated damages in its dispatch analysis by recognizing that these costs will be incurred if the units are not dispatched at a level that consumes coal above the contractual minimums.
>
> For example, suppose the same CSA example in subpart (b) above had a liquidated damages provision in conjunction with the minimum volume of 1,000,000 tons. Therefore, instead of the company having a full take-or-pay provision and being obligated to pay $2/MMBtu for any shortfall of volumes below 1,000,000 tons, the liquidated damages provision called for a payment of $0.25/MMBtu for any shortfall. Therefore, the "dispatch tier" price would be $1.75/MMBtu for volumes between zero tons and 1,000,000 tons. The dispatch tier for volumes over 1,000,000 tons would be $1.00/MMBtu. If the company purchased 2,000,000 tons, the "costing tier" price would remain at $1.50/MMBtu.[37]

Q. Do you have any concerns about the calculation and use of the two tiers in projecting the least cost dispatch of PacifiCorp's generation fleet?

A. Yes. In my opinion this approach does not result in least-cost dispatch of PacifiCorp's coal units when the full set of resource options and costs is considered. Similarly, even if the approach were appropriate, the specific pricing tier inputs used by PacifiCorp in the GRID model have significant discrepancies with the ones that result from the methodology described by PacifiCorp in SC 1.4 and the coal contract prices included in the workpapers of Mr. Ralston.[38] I elaborate on this opinion to explain both my concerns

[36] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 1.4 (b).
[37] *Id* at 1.4(c)
[38] I compare the GRID tiers provided in the work paper to the Application of PacifiCorp, ORTAM21_Fuel Price (1912) CONF.xlsm, tab 4 GRID Coal 2019+ with my calculations based on the contract data found in the work papers to the Direct Testimony of Dana Ralston on Behalf of PacifiCorp.

with PacifiCorp's general methodology and the specific inputs it has used in my testimony below.

Q. Can you explain your general methodological concerns with PacifiCorp's tiered pricing approach in the GRID model?

A. Yes. The tiered pricing approach that PacifiCorp used to estimate incremental versus fixed fuel costs might initially seem to have some merit, but actually leads to significant distortions within the context of calculating NPC. I will explain the logical gaps in PacifiCorp's approach both in cases where contracts that have minimum take-or-pay provisions (as described in SC 1.4(b)) and also for contracts that have no such provisions (as described in SC 1.4.(d)). I am choosing not to focus on contracts that include liquidated damages provisions as those are mainly for transportation and account for a smaller percentage of the overall cost.

Q. Please explain why PacifiCorp's application of the dispatch and costing tiers is inappropriate and ultimately leads to uneconomic dispatch at the expense of its captive customers.

A. PacifiCorp appears to have relied exclusively on the "dispatch tier" price to estimate its generation units' output in the NPC forecast, to set prices in the EIM and/or bilateral transactions, and even for dispatch decisions within its own system. However, PacifiCorp's use of "incremental" fuel costs as the sole basis of its dispatch tier pricing (while excluding "non incremental" fuel costs) is highly mistaken. In principle, this approach relies on the concept of marginal pricing, i.e. the output of a unit can be sold at any price higher than the incremental cost of producing it. The notion that prices should be set equal to or greater than marginal costs is a foundational principle of economic theory and is common practice in competitive markets. However, even in economic theory, marginal pricing has a significant pre-requisite: that is, the marginal cost (i.e. dispatch tier) must be higher than the average cost (i.e. costing tier). Unless this is true, the company will consistently experience economic losses over the long term and the optimal decision would be for the plant to shut down or review its pricing. By choosing to characterize the minimum take portion of its fuel costs as "non-incremental" or fixed costs, PacifiCorp can claim artificially low marginal costs and thus make its coal units appear more competitive. When pricing its units based on this "incremental marginal" cost, PacifiCorp cannot recover the full costs of operating these units, including the "fixed" fuel costs.

Q. If PacifiCorp is not including the full cost of fuel when estimating the marginal costs for its coal units, how are these units able to continue operating?

The only reason PacifiCorp has been able to keep operating those units despite these artificially depressed prices is that it is able to recover its remaining "fixed" fuel costs from its captive customers through fuel adjusters like the TAM. In a competitive open market, PacifiCorp would have significant economic losses following this same practice. As a regulated utility, these highly inefficient expenses simply get passed to captive ratepayers.

Q. Can you further illustrate why treating minimum take provisions as a fixed cost and excluding these costs from dispatch decisions is problematic for Oregon ratepayers?

A. Yes. As a hypothetical example, assume that the price for the take or pay portion of all of the Company's CSAs doubled in 2021. Following the exact methodology described in SC 1.4., the forecasted MWh of coal generation would remain unchanged from its present

2021 forecast despite the fact the coal fuel expenses recovered through the TAM would have roughly doubled. The higher fuel costs would not trigger any additional replacement of coal-generated energy from other resources because the dispatch costs, which do not depend on the price or volume of the minimum take provision, would remain the same. Thus, PacifiCorp's approach results in a highly erroneous cost comparison of different resources and does not lead to the most economically efficient dispatch of PacifiCorp's resources. Within the TAM, PacifiCorp is not incentivized to optimize its operations and fuel supply, as it will not suffer the economic losses that its practices would generate in a truly competitive market environment.

Q. Besides excluding the fixed component of fuel costs, are there other ways that PacifiCorp is distorting the dispatch tier pricing, and subsequent generation estimates?

Yes, even in the absence of fixed costs, PacifiCorp has included very low dispatch tiers for some units following a simple technique: it adds a small supplemental quantity to be purchased on top of the base quantity at a fraction of the base (or tier 1) price. Then it models the entire unit's dispatch at this lower dispatch tier price.

Q. Can you provide a simple analogy for this erroneous practice?

A. Yes. Assume that a small business needs to buy 10 chairs for a new office. When looking at their options, one brand seems to be by far the least expensive, costing only $50 for a chair. At that point, a decision is made to buy 10 chairs of that brand (or $500 total). But when the time comes to pay and the business has already committed to buy the chairs, it is revealed that only the tenth chair is available at that price, the first nine cost $100 each (or $950 total). Another brand could have been available at $60 per chair for all 10 chairs

($600 total), but the decision was made based only on the "incremental" price of the last chair. This would be bad decision-making and bad public policy. Similarly, GRID decides which units to dispatch based on the cost of the dispatch tier which for some units is only for a supplemental quantity and significantly lower than the base price. But when calculating costs to be recovered by Oregon ratepayers, a much higher price is charged for the vast majority of the unit's output. This practice results in overgeneration from expensive units that displace lower cost generation and lead to excessive NPC. Following this methodology, PacifiCorp has been able to dispatch the Jim Bridger plant much often more than would be prudent, while at the same time buying coal [redacted] from its very own Bridger mine. I provide more details throughout this section.

Q. Are you opposing minimum take provisions?

A. Yes. The minimum take provisions have traditionally been part of CSAs and might be required from the seller; however, given the significant role these provisions play in fuel costs ultimately paid by ratepayers, and the significant distortions they can cause, I believe they require significantly increased scrutiny by the Commission and other stakeholders. This includes the ability to review these provisions before being included in any future contracts executed by PacifiCorp for which fuel costs are expected to be recovered through retail rates. Ideally, CSAs with minimum takes should only be executed after a careful examination of the optimal operation of a unit and the calculation of its fuel requirements based on the appropriate comparison of its *full* costs (including minimum quantities) with other resources.

Q. Is the TAM the appropriate venue for the Commission to review these provisions?

A. No, not in my opinion. The TAM is narrowly tailored to review fluctuations in short-term variable fuel costs from year to year, rather than multi-year contractual decisions for fixed fuel costs that have long-term implications. Currently no forum, to my knowledge, explicitly reviews fixed fuel costs over the medium to long-term that result from contractual decisions such as entering into a CSA. While this determination might be able to occur in the TAM, in my opinion, it is more appropriate for proceedings that authorize recovery of other long-term fixed costs, such as a general rate case, or make long term planning decisions, such as the IRP. Regardless of whether or not this review is provided ahead of time, the fixed fuel costs that arise from long-term contracts should be subject to prudency determination before being included in rates. As such, the fixed fuel component should be excluded from the TAM until such determination is made.

Q. Given that many of PacifiCorp's CSAs include minimum-take provisions contributing to the higher NPC costs in the long-term, what is your recommendation on cost recovery?

A. PacifiCorp considers the cost of coal in a take-or-pay volume tier to be not avoidable.[39] Whether they are avoidable or not for PacifiCorp does not render them immune to disallowance if they are imprudent. As long as cost-minimizing unit dispatch exhausts the minimum tonnage of the CSAs, then these costs can be recovered as fuel expenses. However, the least cost dispatch should be the one that leads to the lowest cost for ratepayers inclusive of all costs that they will have to cover. On the contrary, up to now, contractual minimum tonnages have been leading the units' dispatch. Ratepayers should

[39] Sierra Club/104.-ECAC Wilding Rebuttal at 8:8-10.

not be expected to cover excessive costs just because PacifiCorp has agreed to them outside of TAM.

Q. How are fuel costs treated in PacifiCorp's IRP modeling?

A. According to SC 1.3, the model used in the IRP proceeding dispatches using average prices. This contrasts with the TAM, where GRID dispatches units based on their incremental fuel costs. This leads to significantly different generation forecasts as shown in the table below:

Table 8: Projected Coal Generation in IRP and TAM

	Generation (MWh)		Capacity Factor (%)		Difference
	IRP	TAM	IRP	TAM	
Colstrip	[redacted]				
Craig					
Dave Johnston					
Hayden					
Hunter					
Huntington					
Jim Bridger					
Naughton					
Wyodak					
Total					

The difference in generation is a product of the different fuel costs used in the two proceedings. In both modeling exercises the total ratepayer cost includes all associated fuel costs, but PacifiCorp is able to justify higher generation in the TAM based on characterizing certain fuel costs as incremental and others as non-incremental. The mere fact that an agreement was signed does not change how much coal is economic to burn relative to other resources, nor should it increase the expenses ratepayers pay. The treatment of some costs as fixed and the inclusion of supplemental low-priced contact quantities make coal seem more economic and can lead to costly lock ins, but in the end, ratepayers are asked to cover its full price. The use of a dispatch tier is a construct that PacifiCorp has relied on to keep operating some units. In the long run, all costs included, this construct has led to higher costs for ratepayers.

Q. Why is the dispatch of the Naughton, Jim Bridger, and Hayden plants so significantly different in the two studies?

A. The difference in Naughton and Jim Bridger can be explained by the lower dispatch tier used in TAM compared to the average cost used in the IRP. While the difference in Naughton (even if it leads to higher ratepayer costs) can be justified based on the contractual minimum fuel requirement, there is no such requirement for Jim Bridger at that level of fuel consumption. This indicates that TAM over-dispatches Jim Bridger based on artificially low costs, in an effort to justify the plant's operations, as well as its unreasonably high-priced supply from PacifiCorp's own mine. Finally, the significantly higher generation of Hayden in TAM cannot be justified by cost inputs, and is probably the result of other constraints within GRID. Hayden has the second highest dispatch tier (as shown in Table 7), but GRID still dispatches it at the highest capacity factor. Once again, this re-enforces my opinion that GRID includes many constraints that prevent it from reaching a least cost dispatch and rather lead it to PacifiCorp's desired, almost pre-specified outcome.

Q. Since the IRP and TAM serve different purposes, how should the comparison of projected capacity factors inform this proceeding?

A. Although the two proceedings serve different purposes and have different planning timelines, they still have the same objective of minimizing cost for ratepayers. Whether the IRP recommended additions and retirements really serve to minimize cost for ratepayers in the long term depends on how those plant decisions will lead to operational changes in the short term. If the forecasted operations of the units in the two proceedings differ significantly then the energy cost for ratepayers is not minimized, as the system does not operate as planned.

Q. In addition to your overarching concerns with PacifiCorp's general approach to tiered pricing, are you also concerned with the specific inputs selected for certain plants according to PacifiCorp's methodology?

A. Yes, that's correct.

Q. Can you please elaborate?

A. Yes. I have examined the methodology PacifiCorp described in SC 1.4 for calculating the dispatch tier and costing tier prices. Using information provided in Mr. Ralston's testimony on coal contract provisions, I have attempted to reconcile this methodology with the pricing tier assumptions used in the GRID model. In performing this analysis, I noticed several discrepancies for individual plants. Specifically, I evaluated the discrepancies that occurred at the Naughton, Jim Bridger, Hunter and Huntington plants. I will explain each of these below.

Q. Has PacifiCorp provided you with its workpapers for calculating the dispatch tier prices?

A. Yes, these were provided two business day prior to the filing deadline of this testimony in response to a discovery request from Sierra Club. My preliminary review revealed that PacifiCorp's own calculations led to different dispatch tier prices than the ones that the company used in its GRID model for the 2021 NPC projections.

Q. Please describe the discrepancies identified for the Jim Bridger plant as included in TAM 2021.

A. Jim Bridger is currently fueled by two providers, BCC and Black Butte Coal Company. According to the confidential workpaper "BRIDGER. xlsx", PacifiCorp's CSA with Black Butte has a minimum take volume of [redacted] million tons at [redacted].[40] The second supplier, BCC is a jointly-owned, indirect subsidiary of the Jim Bridger plant owners, including PacifiCorp. As such, no minimum take tonnage shortfall payments are assessed by BCC. The mine can provide [redacted] tons of coal at a price of [redacted], [redacted], and a supplemental quantity of [redacted] tons at a price of [redacted] Details can be found in Exhibit Sierra Club/108.

[40] Confidential Workpaper to the Direct Testimony of Dana Ralston on Behalf of PacifiCorp,"BRIDGER.xlsx", tab Details.

Table 9: Jim Bridger Coal Supply[41]

	Jim Bridger
Mine	[redacted]
Type	
Term End	
Tons Received	
Coal Price $/Ton	
Btu's/lb	
MMBtus received	
Adjustments[42]	
Dollars/Ton Received	
Dollars/MMBtu Received	

GRID is using a costing tier of [redacted] and a dispatch tier of [redacted] Following the methodology described in SC 1.4., I calculated the costing tier for the consumed coal to be consistent with the GRID input (as a weighted average of the coal volume from the three categories). However, I found the dispatch tier used in GRID to be significantly different than the incremental cost of coal according to the contracts. Following PacifiCorp's definition for the dispatch tier, this would be:

- $0/MMBtu for volumes below Black Butte's minimum take volume ([redacted])
- [redacted] for volumes between [redacted] and below [redacted]

[41] Confidential Workpaper to the Direct Testimony of Dana Ralston on Behalf of PacifiCorp, "BRIDGER.xlsx", tab Details; Sierra Club/107, Confidential Attachment to PacifiCorp Response to Sierra Club 1.6.

[42] According to confidential workpaper "BRIDGER.xlsx", tab Details the BCC supply is subject to various adjustments that reduce the price from [redacted] to [redacted]n:

[redacted]

- [redacted] for consumption above [redacted] tons

GRID dispatched Jim Bridger based on a single dispatch tier of [redacted].

Comparing the calculated dispatch tier (based on PacifiCorp provided methodology and coal prices) and the GRID dispatch tier, I make the following findings:

a) The supplemental coal represents approximately 1% of the plant's supply. Still the entire coal supply is represented by a single dispatch tier

b) The numerical value that PacifiCorp uses is inconsistent 50with the coal price even for the supplemental coal cost. Specifically, the dispatch tier for the supplemental quantity is [redacted]. PacifiCorp uses a dispatch tier of [redacted].

c) The projected consumption is [redacted],[43] which after the consumption of the minimum tons from Black Butte leaves [redacted] to be consumed from BCC. This means that the plant would NOT require the supplemental quantity and the incremental cost of coal should in fact be [redacted]. This is equal to the Bridger Mine base contract price which is not subject to any minimum take provisions and would most accurately represent the marginal cost.

In short, PacifiCorp is modeling Jim Bridger's generation output by assuming a marginal fuel cost that is half of what its actual marginal fuel cost is. Still ratepayers are asked to pay for the full price of the fuel.

[43] Sierra Club/109, Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.7.

Q. Can you explain why using a single dispatch tier is problematic for Jim Bridger?

A. GRID only uses one tier to dispatch the units. In the case of Jim Bridger, that would be the last tier of [redacted]. However, this leads to significant overgeneration from that plant. I cannot run the GRID model myself, but I provide a hypothetical numerical example. Assume that when including a dispatch tier of [redacted] the Jim Bridger fuel requirement in GRID equals [redacted]. However, when including a dispatch tier of [redacted] (which again is a dispatch tier, but the one representing the majority of the plant's consumption), the Jim Bridger fuel requirement in GRID would be much lower – assume an approximately 40% reduction, or [redacted] consumed tons.[44] Assuming that Jim Bridger would first consume its minimum take volume from Black Butte, optimizing consumption based on the first tier of [redacted], would result in a consumption of [redacted] million from Black Butte and only [redacted] ton from BCC. Instead using the second tier (or supplemental) pricing of [redacted] results in [redacted] tons. This means that any ton consumed above [redacted] tons is a ton falsely consumed in GRID based on an erroneous input of lower dispatch tier, which would not be consumed when accounting for the right dispatch tier. Every ton above [redacted] is paid for by ratepayers at its full cost of [redacted], but displacing electricity that could have cost as low as [redacted]. Similarly, when Jim Bridger is dispatching to sell electricity off-system this electricity is sold based on a cost of [redacted]. PacifiCorp then claims that this sale is beneficial for ratepayers reducing the NPC by [redacted] for the energy sold,

[44] Although this is hypothetical, PacifiCorp has conducted a GRID run presented in the rebuttal testimony of Mr. Wilding in ECAC 2020, in which GRID used the costing tiers for Jim Bridger and Naughton and their combined output fell by [redacted]. Sierra Club/104, ECAC Wilding Rebuttal at 11:17-12:13.

but asks customers to subsidize the [redacted] cost through increased fuel consumption.

Q. Do you have other concerns regarding the Jim Bridger fuel supply?

A. Yes. Mr. Ralston presents the coal supply from BCC as adding flexibility because it can be flexed down.[45] There are a couple of observations worth noting regarding this statement. First, BCC has the [redacted] expensive coal supply among all of PacifiCorp's suppliers. Second, the stated flexibility comes at a very high cost. According to Table 3 in Mr. Ralston's testimony, deliveries from BCC fell from [redacted] tons in TAM 2020 to [redacted] tons while fuel payments for BCC fell from [redacted] million in TAM 2020 to [redacted] million in TAM 2021.[46] This means that every ton not delivered results in avoided costs of [redacted]. BCC, however, has a base price of $[redacted]. The reason is because "BCC operating costs include fixed costs that do not correlate with annual changes in coal production."[47] Thus, not only are the BCC fuel costs extremely expensive, they are only likely to rise as less fuel is consumed. Consequently, this raises general questions regarding the overall viability of the BCC mine and the prudency of keeping it operational.

Q. Please describe the coal supply for the Hunter plant as included in TAM 2021.

A. Historically, the primary coal supply for the Hunter plant has been provided through a coal supply agreement with Wolverine Fuels, LLC (Wolverine). The Hunter agreement with Wolverine ends in 2020. According to Mr. Ralston, for the 2021 TAM, the pricing

[45] PAC/300, Ralston/3:17-21.
[46] *Id.* at Ralston/7, Table 3.
[47] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 1.29(b).

for coal costs is based upon a market forward price for Utah coal, as published in Energy Ventures Analysis Fuelcast in November 2019.[48] The costing tier for Hunter is [redacted][49] which is consistent with the assumed coal cost presented in Mr. Ralston's testimony including contributions to the 1974 United Mine Workers Association pension ([redacted]).[50] However, PacifiCorp's testimony omitted the fact that Hunter is dispatched within GRID based on an unfounded dispatch tier of [redacted].[51] It is of critical importance to model Hunter's projected consumption appropriately, as this number might be used to inform contract negotiations and consequently lock the system to sub-optimal operations for years to come. Meanwhile, since there is currently no CSA in place at Hunter for 2021, it is only appropriate to use the full costing tier price of [redacted], rather than the severely discounted assumption used by PacifiCorp of [redacted].

Table 10: Hunter Coal Supply[52]

	Hunter
Mine	[redacted]
Tons Received	
Coal Price $/Ton	
Btu's/lb	
Refined Coal	
West Pension	
Transportation	
Dollars/Ton Received	
Dollars/MMBtu Received	

[48] PAC/300 at Ralston/14: 9-11.
[49] CONF ORTAM21_Fuel Price (1912), tab 4 GRID Coal 2019+.
[50] PAC/300 at Ralston /14:14, Ralston/15:20-16:3.
[51] CONF ORTAM21_Fuel Price (1912), tab 4 GRID Coal 2019+.
[52] Confidential Workpaper to the Direct Testimony of Dana Ralston on Behalf of PacifiCorp, "HUNTER.xlsx", tab Details; Sierra Club/107, Confidential Attachment to PacifiCorp Response to Sierra Club 1.6.
[53] Assumption in Confidential Workpaper to the Direct Testimony of Dana Ralston on Behalf of PacifiCorp, "HUNTER.xlsx", tab Details. Hunter currently has an open coal position for 2021.

Q. Please describe the coal supply for the Naughton plant as included in TAM 2021.

A. The Naughton plant is supplied by the adjacent Kemmerer mine under a long-term coal supply agreement through 2021. The CSA calculates tier-1 and tier-2 tonnage volumes and pricing based on a July-to-June contract year. The tier 1 price is the [redacted]. As a result of Naughton Unit 3 discontinuing as a coal-fired resource in January 2019, PacifiCorp exercised an environmental response provision to reduce the minimum annual tonnage after it ceased burning coal at Naughton Unit 3 on January, 2019 in compliance with the requirements of the Wyoming Regional Haze state implementation plan.[54] As a result, the annual minimum take-or-pay quantity was reduced from [redacted] million tons to [redacted] million tons.[55] The environmental shortfall payment equals [redacted] million for 2021[56] and is included on a per MMBtu basis in the costing tier price ultimately used by PacifiCorp to calculate the NPC. Similar to the Jim Bridger plant, the GRID costing tier reflects the weighted average cost of the two tiers [redacted].[57] The GRID dispatch tier is [redacted]/MMBtu, still slightly lower than the real contract price in tier 2.[58] Again, the significant error in modeling Naughton's operations is that a single dispatch tier is used to model the entire amount when [redacted]. Similar to Jim Bridger, Naughton generation is over-projected due to the difference of the tiers and results in higher costs for ratepayers. In addition, Naughton is also subject to an additional "minimum burn"

[54] Sierra Club/105, Redacted PacifiCorp Response to Sierra Club Data Request 1.31.
[55] Sierra Club/111, Confidential PacifiCorp Response to Sierra Club Data Request 1.31(b).
[56] Confidential Workpaper to the Direct Testimony of Dana Ralston on Behalf of PacifiCorp, "NAUGHTON.xlsx", tab Details; PAC/300 12/1.
[57] CONF ORTAM21_Fuel Price (1912), tab 4 GRID Coal 2019+.
[58] *Id.*

modeling constraint to consume all of its minimum take volume. This is covered later in my testimony.

Table 11: Naughton Coal Supply[59]

	Naughton
Mine	[redacted]
Type	[redacted]
Term End	[redacted]
Tier	[redacted]
Tons Received	[redacted]
Coal Price $/Ton	[redacted]
Btu's/Lb	[redacted]
Btu Adjustment ($/ton)	[redacted]
Iron & Calcium Premium ($/ton)	[redacted]
Environmental Provision Payment	[redacted]
Dollars/Ton Received	[redacted]
Dollars/MMbtu Received	[redacted]

Q. Please describe the coal supply for the Huntington plant as included in TAM 2021.

A. The primary coal supply to the Huntington plant is also provided under a requirements contract with Wolverine. This is a "delivered to the plant" agreement that requires Wolverine to pay the transportation costs, although PacifiCorp is responsible for limited trucking cost escalation. The Huntington plant had also received coal under a coal supply agreement with Rhino Energy, LLC's Castle Valley mine. That coal supply agreement, however, ends December 31, 2020. The Castle Valley mine has supplied [redacted] tons of coal annually to the Huntington plant. According to Mr. Ralston, "[a]s the Wolverine coal supply agreement is a requirements contract, the volume that was previously purchased

[59] Confidential Workpaper to the Direct Testimony of Dana Ralston on Behalf of PacifiCorp, "NAUGHTON.xlsx", tab Details; Sierra Club/107, Confidential Attachment to PacifiCorp Response to Sierra Club 1.6.
[60] In this table, the environmental provision payment is included in the dollars/ton received and dollars/MMBtu received of Tier 1.

under the Castle Valley contract will now come from the Wolverine coal supply agreement."[61] Coal prices increased from [redacted] in the 2020 TAM to [redacted] n in the 2021 TAM, as discussed by Mr. Ralston.[62] What Mr. Ralston failed to mention is that Huntington's supply in GRID is modeled based on a completely different price. The $[redacted] would translate to $[redacted] but GRID uses an unfounded dispatch tier of [redacted]. An unjustifiably lower dispatch tier, Huntington's projected consumption is still shy of the modeled minimum take requirement.[63] Had Huntington's coal supply been priced appropriately within GRID, the optimal fuel consumption would be even lower. It is my opinion that Oregon ratepayers stand to benefit if PacifiCorp could avoid increasing the minimum take volume from Wolverine to reflect the Castle Valley quantity.

Table 12: Huntington Coal Supply

	Huntington
Mine	[redacted]
Type	
Term End	
Tons Received	
Coal Price $/Ton	
Btu's/Lb	
Miner Act	
West Pension	
Transportation	
Dollars/Ton Received	
Dollars/MMbtu Received	

[61] PAC/300 at Ralston/15:12-15.
[62] *Id.* at Ralston/15:2-3
[63] Sierra Club/109, Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.7 (Huntington is projected to burn [redacted], while it is assumed to have a minimum take requirement of [redacted]).

Q. What is your recommendation for future use of the two tiers and resulting over-dispatch of coal units?

A. I recommend that future TAM modeling use input assumptions that are more reflective of the full cost of fuel. Going forward, the Commission should require that whenever PacifiCorp estimates future plant generation levels (MWh) when using the GRID model (or any successor tool) that it use the costing tier input values, rather than the dispatch tier values. This will ensure that generation levels are estimated based on the full and true cost to PacifiCorp customers rather than a discounted amount.

C. GRID Model Constraints and their Impact on Coal Generation Projected in the 2021 NPC

Q. Please describe your concerns regarding additional constraints on coal unit operations in GRID.

A. GRID is a production cost model, and as such it contains several technical constraints including transmission constraints or minimum operation levels for its coal units. These represent actual physical limits of the system that should be preserved during operations. However, it is my understanding that GRID contains additional constraints that do not represent necessary technical constraints, but selected choices of the modelers (i.e., PacifiCorp). These constraints lead the model output to significantly deviate from the true least cost dispatch. These constraints include:

- Must-run constraints for the coal units
- Minimum fuel burn constraints

I explain both below.

Q. Please explain must-run constraints.

A. It is my understanding that GRID includes must-run constraints for all of PacifiCorp's coal units. Those constraints dictate that coal units should be online throughout the year independent of their cost.[64] Absent these constraints, the plants would be able to perform economic cycling, i.e. GRID would only dispatch coal units when it is cost minimizing to do so. *According to OPUC 6(c)*, "[e]conomic cycling is the act of temporarily reducing a unit's output to zero because it is the cost-minimizing option, as opposed to doing so in order for maintenance work to be performed or because of system restrictions."[65]

Q. Is PacifiCorp allowing economic cycling for any of its coal units?

A. Yes. In TAM 2021, PacifiCorp models economic cycling but only for units 1 and 2 at the Hunter plant and only for the months February to May.[66]

Q. Why is PacifiCorp allowing economic cycling only for two units?

A. According to SC 1.24, economic cycling is only for coal plants that are majority-owned by PacifiCorp, "that are not participating in the Western Energy Imbalance Market (EIM), and that are not under operational constraints that would preclude an economic shutdown."[67] Regarding minority owned plants, PacifiCorp has briefly discussed economic cycling with other owners but according to OPUC 11 "due to differing system load and market dynamics no agreement on shutdowns was possible."[68] Furthermore, according to OPUC 9, "historically, coal units that participate in the energy imbalance

[64] Allowing for planned, maintenance, or other necessary shutdowns.
[65] Sierra Club/105, PacifiCorp Response to Staff Data Request 6(c)(iv).
[66] PAC/100 at Webb/17:21-23.
[67] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 1.24(a). Sierra Club/105, PacifiCorp Response to Staff Data Request 107 (defines operational constraints as "not a finite list of itemized possibilities").
[68] Sierra Club/105, PacifiCorp Response to Staff Data Request 11.

market ("EIM") generally have not been cycled off for economic purposes. Because EIM participating coal units can provide benefits to customers because of their flexibility in the EIM, non-participating coal units are typically chosen for economic cycling before EIM participating coal units."[69]

Q. Do you agree with PacifiCorp's selection of units that are allowed to cycle economically?

A. No. First, despite the existence of different owners, market dynamics are similar with the cost competitiveness of coal generation falling universally. Economic cycling could deliver benefits not only to PacifiCorp's ratepayers, but to the rest of the owners' systems. It is my opinion that the recognition of such value proposition should lead PacifiCorp to continue these conversations. Lack of communication and willingness to collaborate should not be a barrier in achieving benefits for ratepayers. Additionally, independent of other owners' decisions on economic cycling, PacifiCorp should still be able to reduce delivery of its ownership share to achieve the same benefit. Second, although EIM participation delivers benefits for ratepayers, it is not apparent to me that EIM participation and economic cycling are mutually exclusive. Based on my understanding of the EIM rules, participating entities are able to submit a day-ahead base schedule for participating resources as long as 7 days ahead of time and submit a real-time schedule as little as 75 mins ahead of time. This should provide PacifiCorp with enough flexibility to economically cycle coal resources based on its own needs, as well as participate in the EIM when coal units are being dispatched.

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[69] Sierra Club/105, PacifiCorp Response to Staff Data Request 9.

Q. Why is PacifiCorp allowing economic cycling only for the months of February to May?

A. According to OPUC 8 "[t]he cycling period used in the transition adjustment mechanism (TAM) is informed by the historical data as to when coal units have been economically cycled in the past. Historically, economic cycling of coal units has occurred in the spring because of reduced loads and hydro and solar conditions."[70]

Q. Do you agree with PacifiCorp's selection of months during which units are allowed to cycle economically?

A. No. This is one more instance in which PacifiCorp imposes its own choice to the model, distorting the model's ability to achieve a least cost dispatch. The fact that these months are the ones during which PacifiCorp decided to allow economic cycling in the past does not justify why this should remain the case, nor does it provide evidence that if allowed to cycle economically throughout the year, they would not do so. After all, if allowed, units would be forecasted to shut down only if it was cost minimizing to do so, but would be forecasted to operate otherwise. It is unreasonable for PacifiCorp to make this determination *a priori*, instead of truly evaluating the benefits that could result from such a dispatch through modeling.

Q. How do the two Hunter units' operations change when allowed to cycle economically?

A. Allowing Hunter units 1 and 2 to cycle economically for this short period leads to a reduction of [redacted] of its output for Hunter 1 and [redacted] for Hunter 2. Below is a table with the units' operations with and without economic cycling.

[70] Sierra Club/105, PacifiCorp Response to Staff Data Request -8.

Table 13: Hunter 1 & 2 Generation (MWh) under economic cycling[71]

	February	March	April	May
[redacted]				
Hunter 1	[redacted]			
Hunter 2				
Hunter 1	[redacted]			
Hunter 2				

Q. What is the impact of allowing the economic cycling of those units on NPC?

A. Economic cycling of those two units for this short period of time leads to NPC savings of $[redacted].[72]

Q. What do you conclude from observing the impact of economic cycling on NPC?

A. First, the difference in the units' operations is a clear indication of how uneconomic they are. It is worth noting that Hunter has an average generation cost below the average cost of PacifiCorp's coal units. Thus, I can confidently conclude that if economic cycling were allowed for all of the units throughout the year, coal generation would dramatically decline, and significant NPC savings could be achieved.

Q. What do you recommend based up on your observations and analysis?

A. First, I recommend that PacifiCorp allow economic cycling (rather than must-run constraints) for all plants as the default assumption when calculating NPC going forward. Second, I recommend that PacifiCorp study whether greater savings could be achieved for its customers if it were to 1) allow its plants to perform economic cycling rather than

[71] Confidential Workpaper to the Direct Testimony of David Webb on Behalf of PacifiCorp, "ORTAM21 SL04 Coal CC CONF.xlsm", tab GRID Thermal Gen by Unit (MWH).
[72] PAC/104 at Webb/1.

participate in the EIM, and 2) allow its plants to simultaneously perform economic cycle and participate in the EIM.

Q. Please explain minimum burn constraints.

A. It is my understanding that in addition to must run constraints and the misleading use of lower dispatch tiers, the operation of some units is further constrained by manually imposed minimum burn constraints, i.e. constraints that dictate that certain units should consume at least a minimum quantity of fuel. One such example is the Naughton plant. According to SC. 1.30, the minimum contractual obligation or requirement of [redacted] is modeled as a minimum requirement and any generation determined by GRID above that amount is economic.[73] Thus, generation from the Naughton plant is exogenously constrained to consume at least [redacted] independent of plant economics. Above that amount, GRID can choose whether to further dispatch the units or not based on economics. It is worth mentioning that GRID forecasts fuel consumption at Naughton exactly equal to [redacted] for the plant, which indicates that when given a choice to dispatch the plant at any amount above the minimum, GRID chooses not to do so. The minimum burn constraint is the reason that the Naughton plant has such a high capacity factor despite having the highest average cost of generation. Under a true least cost dispatch, its generation and associated ratepayer costs would be significantly lower than what the GRID model has projected.

[73] Sierra Club/111, Confidential PacifiCorp Response to Sierra Club 1.30.

Q. Are other units also subject to minimum burn constraints?

A. Yes. According to SC 3.11 there are minimum burn constraints at all plants that are subject to contractual minimum take payments including [redacted], [redacted].[74] As most of the units are forecasted to generate close to their minimum take requirement this raises the question of whether the TAM dispatch is really a product of least cost modeling, or the arise from intentional modifications to the modeling parameters to achieve a certain result.

Q. What is your recommendation on the issue of economic cycling and minimum burn constraints?

A. The Commission should seek to allow an NPC that is not artificially dictated by PacifiCorp's desired output. To achieve this, GRID modeling should allow economic cycling for all of the units throughout the year, not include minimum fuel constraints, and dispatch units based on actual costs rather than minimum burn requirements. This is because PacifiCorp's goal in determining optimal dispatch and forecasting NPC is to "minimize power costs holistically over the forecast period,"[75] and significantly costlier to ratepayers. When constraining a model by including inputs of how to operate the units and how much fuel to consume, the output reflects the modeler's choices, not the least cost dispatch. I describe the recommended model changes further in section 9.

[74] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 3.5 and 3.11.
[75] Sierra Club/104, ECAC Wilding Rebuttal at 10:16-18.

6. PacifiCorp's Business Practices for Plant Operation and Fuel Contracting Are Subject to the Same Modeling Fallacies

Q. How could the modeling issues identified above lead to excessive generation at PacifiCorp's coal units in real-world operations?

A. There are a few ways this could occur. First, just as the production cost inputs for specific coal units could be set too low in the GRID model, PacifiCorp could use bid prices that are below the plant's true costs for its wholesale market transactions. I am providing additional information on that in the next section. Second, PacifiCorp might use the overstated generation forecasts modeled in GRID as a starting point for its coal contract negotiations and for establishing minimum tonnages. PacifiCorp then in turn uses these contracted (or anticipated) minimum volumes to guide its operations.

Q. Can you further elaborate on how these modeling inputs and constraints might impact contract negotiations and result in higher minimum tonnages?

A. Yes. It is my understanding that although not clearly structured, contract negotiation for an open coal position starts with an estimation of the fuel requirement. For example, the redacted "PacifiCorp Confidential Long-Term Fuel Supply plan for the Jim Bridger Plant" states that "[t]o develop the 2018 Fuel Plan, PacifiCorp has studied, reviewed and evaluated different fueling options for the Jim Bridger plant. For the 2018 Fuel Plan, the annual generation requirements expressed in consumed tons were derived from PacifiCorp's budget which is calculated using PacifiCorp's Generation and Regulation Initiative Decision Tools (GRID) model[.]"[76] The GRID model in business planning

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[76] PacifiCorp Confidential Long-Term Fuel Supply Plan for Jim Bridger Plan (Redacted Version), Docket No. A.19-08-002 at 3 (Cal. Pub. Util. Comm'n Dec. 19, 2019) [hereinafter "Redacted Bridger Supply Plan"] (attached as Exhibit Sierra Club/112). A footnote is also included mentioning that "The GRID model used for budget purposes is

however is in large part subject to the same constraints as the one used in TAM. When asked to comment on the difference of the GRID model in TAM and the one in business planning, PacifiCorp responded that "PacifiCorp clarifies that the Generation and Regulation Initiative Decision Tool (GRID) is one software model which the Company utilizes for different purposes. The difference between regulatory purposes and business planning purposes is that GRID uses different databases with different inputs and assumptions."[77] Furthermore, PacifiCorp added:

> i. In GRID used for budget purposes, coal plants do not include must run constraints, but are subject to out of model adjustments to ensure that, at least in the near term, contractual minimum purchases are satisfied.
> ii. In GRID used for budget purposes, the minimum fuel consumption constraints are applied to the following coal plants with take-or-pay coal supply contracts – Jim Bridger, Hunter, Huntington, Naughton, Dave Johnston, Hayden, Colstrip and Wyodak.
> iii. In GRID used for budget purposes, coal plants are dispatched using incremental fuel costs. The incremental coal costs are provided from the fuel resources management team.[78]

It is thus my understanding that although a new analysis may be performed "at the time of negotiations for new coal supply agreements based on then current market conditions",[79] the same modelling choices that lead to excessive dispatch of coal units in TAM are also influencing contract negotiations. This creates a "vicious cycle" in terms of the relationship between the coal contracting process and how plant dispatch is projected. The graphic below summarizes this dynamic.

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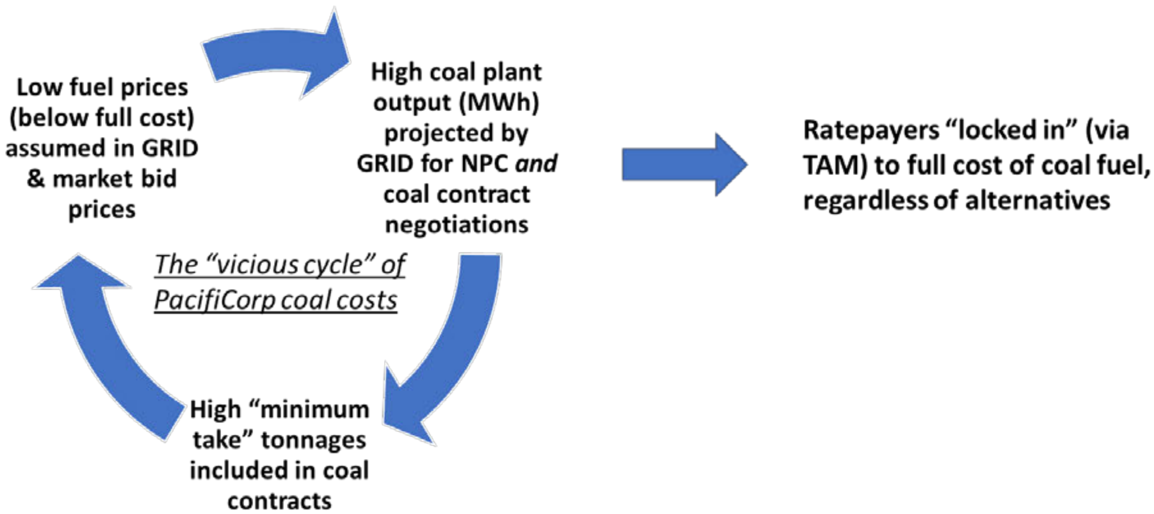
different than the GRID model used in the Oregon TAM. The budget GRID model is used to determine the net power cost budget but is not subject to the same normalizing and regulatory modeling constraints as the GRID model used in the Oregon TAM." *Id.* at 3 n.1.

[77] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 3.5.

[78] *Id.* at 3.5(g).

[79] *Id.* at 3.5(e).

Figure 1: Illustration of the relationship between PacifiCorp's coal contracts, GRID inputs, projected generation levels, and their ultimate impact on ratepayers



Q. **What recommendations do you have for the Commission regarding open coal positions and upcoming CSAs?**

A. Going forward I recommend that the Commission pay close attention to PacifiCorp's decisions regarding any new coal contracts or contract extensions for the plants identified in Table 5 where CSAs are soon expiring. I recommend that the Commission investigate whether these plants are projected to operate economically based on their full fuel costs (including any assumed minimum take quantities that are not currently in effect) and identify opportunities for PacifiCorp to replace coal generation with lower-cost resources. This is especially timely as several of PacifiCorp's contracts end within the next three years. Finally, for plants with existing minimums, I recommend the Commission reconsider how to treat recovery of fuel costs that are essentially "fixed" in nature and whether the TAM is the appropriate venue for this. I will provide some additional details on these issues in the remaining part of my testimony.

7. PacifiCorp's Off-System Sales & Wholesale Market Interactions May be Distorted by the TAM

Q. Are sales for resale a significant component of PacifiCorp's NPC calculation?

A. Yes. Over the last five years, total wholesale sales have fluctuated between $322.8 million and $486.5 million per year.[80]

Q. What are the components of PacifiCorp's sales for resale in TAM?

A. In NPC, wholesale sales represent the revenue the Company receives from various power sales activities: long-term firm sales, short-term firm sales and system balancing sales.

- Long-term firm sales are wholesale sales contracts longer than a one-year period.
- Short-term firm sales are wholesale sales contracts shorter than a one-year period.
- System balancing sales are "model driven" market transactions that economically balance load and resources on an hourly basis.

Both long-term and short-term firm sales are executed transactions during the forecast period on specific terms. Consequently, short-term firm sales included in the TAM represent a snapshot at the time of the filing of actual transactions that have been entered into for the test period, so the TAM 2021 does not currently include the entire amount. System balancing sales have historically comprised the biggest portion of PacifiCorp's wholesale sales in TAM

[80] PAC/100 at Webb/12: 8-9.

Q. Does the TAM include benefits from participating in the Energy Imbalance Market (EIM)?

A. Yes. However, EIM sales are not included within the sales for resale line item in Exhibit PAC/102. Rather, the net benefits from both imports and exports to the EIM are embedded in actual NPC through fuel and purchased power costs.

Q. How is the TAM impacted from off-system sales and EIM participation?

A. The revenues from sales reduce the overall NPC, while the costs associated with increased generation are embedded in the fuel expenses. For EIM participation, net benefits (accounting both for imports and exports) are embedded in purchased power costs and fuel costs. If the company is properly accounting for fixed and variable costs and dispatching units based on least-cost principles, the sale revenue serves to offset the amount of fuel burn expenses charged to customers through the TAM. Depending on the power prices offered to these external systems, sales revenue does not only offset the incremental fuel expense cost but would further reduce NPC, thereby providing a net benefit to PacifiCorp customers.

Q. Have you identified issues with PacifiCorp's approach in modelled and actual sales either bilateral or in EIM?

A. Yes. PacifiCorp's approach both in modeled and actual sales follows the same pricing approach as explained in the previous section with prices derived only based on the "incremental" cost of fuel rather than the total fuel costs, including any fixed components. Although EIM transactions can happen on a sub-hourly basis, planning for them in the TAM has a different timeframe which allows for all of the fuel costs to be considered as incremental. Again, in an extreme hypothetical example, following

PacifiCorp's pricing approach, PacifiCorp could sign a contract with a very high minimum take volume at a high price, then dispatch the unit for sales throughout the year based on an assumed incremental fuel cost (and corresponding bid price) of $1/MWh. This would cause the plant to be dispatched even when the market price is less than its total operating costs. Under this scenario, only a small fraction portion of the true fuel costs would be recouped through sales revenue and the remainder would be charged ratepayers through the TAM. A similar partial recovery of true cost happens when PacifiCorp calculates bid prices based solely on the cost of supplemental quantities throughout the year, while for the vast majority of it, the real cost is much higher (as in the Jim Bridger plant). In short, PacifiCorp can show a net benefit by incorrectly calculating its incremental cost; but in the end, Oregon ratepayers will subsidize any overall losses that the Company experiences through its participation in the wholesale market.

Q. Can you provide a specific example?

A. Yes. PacifiCorp has been bidding generation from Jim Bridger at prices of $[redacted] in the EIM.[81] My understanding is that system balancing sales follow the same approach. This price range is consistent with the "incremental cost" of fuel for the Jim Bridger plant. However, during 2021, after consuming the coal volume specified in the minimum take provision of its CSA with Black Butte, Jim Bridger will be consuming coal from Bridger Coal priced at $[redacted].[82] This would correspond to a cost of

[81] Confidential Attachment "Attach Sierra Club 1.27-3 CONF.xlsx" to PacifiCorp Response to Sierra Club Data Request 1.27, tab BIDS (attached as Exhibit Sierra Club/113).
[82] Full costs were calculated based on 2021 BCC prices (Ralston Workpaper "BRIDGER.xlsx"). EIM bids were calculated based on EIM 2019 data. Confidential Attachment "Attach Sierra Club 1.10-1 CONF.xlsx" to PacifiCorp

approximately $[redacted].[83] Thus an economic bid of $[redacted] during an interval with an EIM clearing price of [redacted] can result in a seemingly beneficial sale with a net profit of [redacted] when only considering the wholesale market. However, in NPC accounting this would be translated to a power purchase cost of [redacted] (i.e. a [redacted] benefit) for one MWh sold and a fuel expense of [redacted]. In short, Oregon ratepayers ultimately have to pay [redacted] to subsidize the sale of one MWh to the market.

Q. Are you opposing off-system sales or EIM participation?

A. No. EIM participation and off-system sales can be beneficial when energy is sold at prices greater than the cost to Oregon ratepayers. Moreover, increased coordination of regional operations, including EIM participation, are extremely valuable steps for adding flexibility to the grid and aiding the integration of renewable resources over the long-term. What I am opposed to is PacifiCorp's specific approach to setting prices when conducting these transactions by consistently underbidding the cost of its coal resources and subsequently charging its retail customers for the difference. If that practice is corrected, then sales can lead to significant long-term benefits for ratepayers and PacifiCorp's participation in these market transactions should be supported.

Response to Sierra Club Data Request 1.10 [hereinafter "Attach Sierra Club 1.10-1 CONF.xlsx"] (attached as Exhibit Sierra Club/114. Although, different years, the comparison remains valid for illustrative purposes. For reference the incremental fuel cost in EIM bids in December 2019 for Jim Bridger was $[redacted]. Although the 2021 incremental cost to be included in EIM bids in 2021 has not been provided, the GRID dispatch tier (which is also characterized as incremental fuel cost) is $[redacted]/MMBtu – which would result in even lower EIM prices.

[83] Sierra Club/111, Confidential PacifiCorp Response to Sierra Club Data Request 1.8 (EIM bid calculation); Attach Sierra Club 1.10-1 CONF.xlsx (EIM 2019 bid data).

8. Summary of Policy Concerns

Q. At a high level, what are the specific policy concerns related to fuel adjusters like the TAM?

A. Since fuel adjusters like the TAM often provide a true-up on a relatively frequent basis (e.g., annually), they tend to shift the risk associated with fuel and operating costs from utilities to their customers, absent rigorous commission oversight. As such, these adjuster mechanisms largely insulate the utility from exposure to fuel price risk, regardless of what may be most economic for customers. Additionally, they may dilute the incentive for utilities to pursue more economic fuel and purchase power options on a near-term basis since cost recovery of these expenses is more or less guaranteed in a timely manner. Finally, as explained throughout my testimony, the adjuster segregates long and short-term planning, which can reduce flexibility in the near term and lead to a lock-in to suboptimal fuel decisions.

Q. Do fuel adjusters like the TAM provide a good incentive to utilities like PacifiCorp that is aligned with the public interest?

A. No. Without rigorous Commission oversight, these types of adjusters could be passing on costs to customers that are not prudent or adequately justified.

Q. Are there any recent examples where uneconomic coal fuel costs are passed on to customers through mechanisms like these?

A. Yes. There have been several. Uneconomic coal dispatch has been most notably observed in relation to the "self-scheduling" practices of coal facilities owned by vertically integrated utilities that also operate in wholesale markets such as MISO and SPP. Specifically, because rate regulated utilities have the opportunity to recover costs through rate cases and fuel adjustment proceedings like the TAM, the regulated utilities have less of an incentive to operate cost effectively relative to the market. There are several ways in which this can happen: a utility might submit a bid to an energy market less than its actual cost of production at a generating unit; a utility can elect to commit a unit to operate irrespective of projected market power prices; or a utility can schedule the full dispatch of a unit irrespective of projected market power prices. In each of these cases, a generator may receive market revenue insufficient to cover its production costs, but simply passes on excess costs to captive ratepayers through rate recovery.

Three organizations recently reported on a trend that regulated utilities frequently engage in uneconomic dispatch of coal plants and pass these costs along to ratepayers. The Market Monitoring Unit of the SPP found that increased self-commitment leads to a distortion of market prices and investment signals, and leads market participants to suboptimal short- and long run decisions.[84] This practice can be contrasted with operating costs and comparatively economic dispatch of merchant coal plants, that routinely dispatch less frequently and at lower average costs.

Additionally, the Union of Concerned Scientists ("UCS") recently completed a study showing that coal self-scheduling in MISO leads to increased costs for customers and distorted wholesale market prices. UCS also compiled a list of state proceedings (primarily fuel adjustment clauses or general rate cases) that relate to the issue of uneconomic coal dispatch as follows:[85]

[84] Sierra Club/103, Self-committing in SPP markets.
[85] Union of Concerned Scientists Panel on Self-Committed Coal in Power Markets (Nov. 2019), *available at* https://ucs-documents.s3.amazonaws.com/clean-energy/Self-Committed+Coal+Presentation+San+Antonio+Nov.+19th.pdf (attached as Exhibit Sierra Club/115).

- CA: PUC Docket No. U 901-E
- IA: IUB Docket No. RPU-2019-0001 (TF-2019-0017, TF-2019-0018)
- IA: IUB Docket No. RPU-2018-0003
- KS: KCC Docket No. 18-WSEE-328-RTS
- LA: PSC Docket U-34794
- MI: PSC Case No. U-20069
- MI: PSC Case No.: U-20471
- MO: PSC Docket No. EW-2019-0370
- MN: PSC Docket Nos. E-999/AA-17-492, E-999/ AA-18-373
- MN: PSC Docket No. 19-704
- TX: SOAH Docket No. 473-17-1764 / PUC Docket No. 46449
- WI: PSC Docket No. 5-UR-109
- WI: PSC Docket No. 6690-UR-126

This indicates that this practice is not only widespread, but of growing concern to state regulatory bodies. Moreover, a recent research report from the Sierra Club estimated that: "captive ratepayers of regulated utility coal plants paid $3.5 billion more for energy from 2015-2017 due to non-economic dispatch relative to the potential procurement of energy and capacity on the market." The same report observed: "While merchant coal-burning power plants must recover all of their costs through energy and capacity markets, coal plants associated with captive ratepayers are able to pass through costs to ratepayers."[86]

Q. Does this potential for overscheduling and uneconomic dispatch depict PacifiCorp's situation?

A. Yes. While PacifiCorp is a vertically owned utility, it is a very active participant in the wholesale energy markets throughout the Western Electricity Coordinating Council ("WECC") region, including both bilateral short-term transactions, as well as

[86] Sierra Club/102, Playing With Other People's Money (Fisher).

participation in the Western EIM and CAISO day ahead markets. This is likely to be of even greater concern as Western wholesale markets evolve to include more enhanced day ahead market options.

Q. Given this context, what concerns does this raise for you regarding the TAM in this proceeding?

A. It is my opinion that the TAM—along with other fuel adjuster mechanisms outside of Oregon—may provide an opportunity for PacifiCorp to compel customers to subsidize uneconomic coal generation. Moreover, there is the potential that the TAM plays a role in distorting wholesale market transactions by favoring the dispatch of coal-fired resources over other cheaper (and often cleaner) alternatives, while suppressing wholesale market prices.

Q. Are there any considerations regarding these wholesale market issues that should be of particular concern given Oregon's existing policies regarding electricity market competition?

A. Yes. It is my understanding that Oregon currently allows for a limited form of retail competition whereby some large commercial and industrial customers can elect a competitive supplier. As such, it appears that Oregon's general policy is to support competition among generation providers. However, as explained in my testimony, the TAM essentially guarantees PacifiCorp that its fuel costs will be recovered from uneconomic coal generators. This provides an unfair advantage to PacifiCorp relative to other competitive suppliers and largely defeats the purpose of Oregon's competitive supply framework.

9. <u>Recommendations</u>

A. 2021 TAM Calculation

Q. Based on the expert opinion you provided in your testimony, do you have any recommended modifications to the 2021 NPC forecast and related TAM rates?

A. Yes. My recommended modifications for the 2021 TAM rates fall into two main categories: 1) Corrections for uneconomic generation forecasted at PacifiCorp's coal units and, 2) Elimination of certain fixed fuel costs that are inappropriately included in the 2021 TAM.

i. Correcting for uneconomic generation at PacifiCorp's coal units

Q. In your expert opinion, what has your review of PacifiCorp's modeling of its generation fleet using GRID revealed?

A. My review has revealed that the forecasted unit dispatch for the 2021 NPC does not reflect the least-cost operations of PacifiCorp's coal units. In fact, coal unit dispatch at several units appear to be overestimated, including at some of the highest cost coal units. This is largely due to artificial constraints built into PacifiCorp's modeling such as "must run" and "minimum burn" constraints. PacifiCorp further sought to influence the dispatch of its coal fleet based on a selective inclusion of costs for each plant as well as the application of "out of model adjustments."[87] This includes the use of dispatch cost assumptions that are severely discounted from the actual fuel costs charged to PacifiCorp ratepayers.

[87] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 3.5 (g).

Q. Do these incorrect estimates of generation in PacifiCorp's model occur even at plants where fuel sources are not subject to minimum tonnage provisions?

A. Yes. In my opinion, PacifiCorp has incorrectly overestimated generation at several plants without minimum take provisions in 2021 including [redacted]. The lack of a minimum take provision is especially relevant because the generation at these plants can be readily ramped down and replaced with other lower-cost generation sources without incurring any take-or-pay penalty costs.

Q. Doesn't the Huntington plant have a minimum take provision in its current CSA?

A. Yes. However, as described in Section 4 of my testimony, the Huntington CSA also contains a provision that [redacted].[88]

Q. Are each of these coal plants projected by PacifiCorp to have relatively high fuel costs in $/MWh terms?

A. Yes. As illustrated by Table 2, they all have above average fuel costs with the exception of Hunter. However, Hunter currently has no contracted fuel supply so the estimated 2021 fuel costs are solely based on forecasts provided to PacifiCorp from a consultant.[89] PacifiCorp has a pending RFP that will provide further information on the actual 2021 fuel costs at Hunter. It is possible that the estimates in the proposed 2021 TAM for Hunter are correct, however they are still unknown as of this filing. In any case, the

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[88] Sierra Club/105, Redacted PacifiCorp Response to Sierra Club 1.31.
[89] OR 2021 TAM Commission Presentation (May 12 2020) (mentioning that Energy Venture Analysis provided estimates).

remedy I propose will ensure that any inaccuracy in PacifiCorp's current estimates of 2021 fuel costs at Hunter do not adversely affect ratepayers through the TAM.

Q. What solution do you propose to correct for PacifiCorp's inaccurate estimates of economic coal generation at plants that lack minimum take provisions?

A. I propose to remove the coal fuel costs from the 2021 TAM calculation for the plants listed above, and to assume a replacement generation cost based on a benchmark value. I propose that this benchmark value be equal to the average of PacifiCorp's projected fuel costs for its natural gas resources in the proposed 2021 TAM (i.e. $20.49/MWh). If adjustments are needed due to differences in the cost of the actual replacement resources in 2021, or if PacifiCorp finds that it is economic to operate these coal units during some hours, PacifiCorp can always make this request in its PCAM filing, along with appropriate justification.

Q. Can you provide an example of how your recommendation would work for a specific plant?

A. Yes. As an example, in its 2021 TAM application PacifiCorp proposes to include [redacted] of fuel costs for [redacted] tons of coal from the Bridger Coal Company (BCC) to supply approximately [redacted]% of the Jim Bridger plant's projected generation of [redacted].[90] The coal supply from BCC is the most expensive on PacifiCorp's system, but the company modelled it as the second cheapest. Specifically, PacifiCorp modeled Jim Bridger with a dispatch cost of $[redacted], while the actual cost charged to customers is $[redacted]. In [redacted] terms, the projected average cost of supply

[90] Sierra Club/109, Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.7 (Calculations based on projected fuel burn, not on delivered fuel tons.).

from BCC is [redacted] and from Black Butte is [redacted], resulting in an average cost of [redacted] for the plant's generation, significantly higher than several alternatives. However, the fuel supplied from the Bridger Coal Company to the Jim Bridger plant is not subject to any minimum take provisions so it can readily be replaced without any penalty. Using the benchmark replacement value of [redacted], replacing [redacted] of generation at Jim Bridger would yield a reduction in the 2021 NPC of [redacted], which translates to corresponding reduction in the TAM rates for PacifiCorp customers.

Q. Under this scenario, could PacifiCorp still choose to supply its customers with electricity from the Jim Bridger plant that was fueled by coal from the Bridger Coal Company if necessary and cost-effective?

A. Yes. However, PacifiCorp would need to justify any coal fuel costs that were in excess of the benchmark rate in its PCAM adjustment filing. I believe this provides an appropriate incentive for PacifiCorp to pursue lower cost, clean energy options while still providing flexibility if there are other extenuating circumstances on PacifiCorp's system that require it to burn coal that is more expensive than other resources, or it is economic to do so in certain circumstances.

Q. Are you proposing any similar modifications to plants with minimum takes?

A. Yes. Hayden's costing and dispatch tier prices in the GRID model do not differ significantly. However, Hayden has the second highest dispatch tier price while it is still forecasted to have the highest capacity factor. This implies the existence of a modeling constraint dictating its dispatch above what would be economic. Recognizing that Hayden has a minimum tonnage associated with a pre-existing CSA, I narrow my recommendation to the costly dispatch above its minimum tonnage and recommend a reduction in the NPC of $0.7 million.

Q. Can you provide a similar estimate of your recommended change to the NPC for the other plants?

A. Yes. I have provided a summary of these changes in Table 14, below.

ii. Elimination of certain fixed costs that are inappropriately included in the 2021 TAM

Q. What has your review of the coal fuel costs PacifiCorp has included in the 2021 TAM revealed?

A. For several coal plants, PacifiCorp treats coal fuel as a non-incremental or "fixed" fuel cost in the calculation of the NPC. This means that PacifiCorp has assumed these costs cannot be reduced even if less coal is consumed.

Q. In your expert opinion, is it appropriate to include fixed costs such as these in an annual fuel adjustment rate like the TAM?

A. No. As a general rule, I believe long-term fixed costs (such as multi-year coal contracts with minimum take provisions) should not be recovered through annual fuel adjusters like the TAM and should be reviewed in proceedings that focus on long-term fixed costs where these contracts can be subject to additional scrutiny and prudency review.

Q. What is your general recommendation regarding these types of long-term fixed fuel costs as it relates to the TAM?

A. I recommend that these types fixed fuel costs be excluded from the TAM for accounting purposes and instead allow PacifiCorp to request their recovery through a more appropriate venue, such as a General Rate Case, if it chooses to do so.

Q. What costs in the proposed 2021 TAM would this exclusion potentially apply to?

A. It would apply to the minimum take fuel costs at Colstrip, Dave Johnston, Jim Bridger (Black Butte mine), Naughton, Hayden, and Wyodak.

Q. Are there any potential exceptions to your general recommendation that might be considered reasonable?

A. Yes. I recognize that some of the coal supply agreements with minimum take provisions have been in effect for many years (e.g. Naughton), and that while those contractual decisions may not have been thoroughly reviewed by the Commission at the time they were executed, it may be difficult to evaluate those contractual decisions for prudency at this late stage.

Q. Given those exceptions, which fixed costs should be considered for exclusion in the 2021 TAM?

A. There are some contracts containing minimum take provisions that have been executed by PacifiCorp very recently and that I believe should be subject to this exclusion. This includes the Colstrip and Jim Bridger (Black Butte) coal supply agreements which were executed in 2019 and 2018, respectively.

Q. What would be the impact if the fixed fuel costs for Colstrip and Jim Bridger (Black Butte) were excluded from the 2021 TAM?

A. Excluding these costs would reduce the 2021 NPC by $97.4 million.

Q. Does this mean that PacifiCorp would be unable to recover these costs?

A. No. However, PacifiCorp would need to seek authorization to recover these fixed costs through an appropriate venue such as a General Rate Case.

Q. Does this mean that PacifiCorp would need to include replacement resources in the TAM?

A. No. This modification does not mean that coal fuel associated with the minimum take provisions cannot be consumed, it simply means the cost recovery of those fuel costs should be treated differently. Thus, no replacement resources need to be considered for the TAM.

iii. Summary of recommended 2021 TAM modifications

Q. Can you provide a summary of your recommended modifications to PacifiCorp's proposed NPC for the 2021 TAM as described above?

A. Yes. The table below provides a summary of these recommended changes.

Table 14: Recommended Changes to 2021 TAM

Plant	Fuel Source	Recommended Change to 2021 NPC Forecast	Rationale	Replacement Assumptions[91]	Change to NPC for 2021 (millions)
Jim Bridger	BCC Mine	[redacted]	[redacted]	Replacement generation costs based on benchmark value	[redacted]
Huntington	Wolverine	[redacted]	[redacted]	Replacement generation costs based on benchmark value	[redacted]
Hunter	TBD	[redacted]	[redacted]	Replacement generation costs based on benchmark value	[redacted]
Craig	Trapper Mine	[redacted]	[redacted]	Replacement generation costs based on benchmark value	[redacted]
Hayden	Twentymile	[redacted]	[redacted]	Replacement generation costs based on benchmark value	[redacted]
Colstrip	Rosebud Mine	[redacted]	[redacted]	No replacement assumed; min take excluded from TAM for accounting purposes	[redacted]
Jim Bridger	Black Butte Mine	[redacted]	[redacted]	No replacement assumed; min take excluded from TAM for accounting purposes	[redacted]
Total					[redacted]
Oregon Portion					[redacted]

[91] Gas benchmark value based on TAM average of $20.49/MWh, ("price to beat"). If adjustment upward needs to be made due to different cost of replacement resources, PacifiCorp can always make a case for this in its PCAM filing.

Q. Did you estimate the total change to the NPC and subsequent TAM rates if these adjustments were made?

A. Yes. I estimate that the 2021 NPC will be reduced by approximately [redacted] in total, or approximately [redacted] for the Oregon portion. I recommend that the corresponding 2021 TAM rates be reduced accordingly.

Q. Are there any other benefits of excluding these costs?

A. Yes. This will help ensure that the TAM/PCAM is not used to subsidize excessive coal plant dispatch, whether for serving its own customers or for wholesale sales. It will also help to align PacifiCorp's wholesale pricing with costs charged to retail customers through the TAM/PCAM. The proposed disallowance can also serve as an incentive for PacifiCorp to reoptimize its operations and achieve a unit dispatch schedule with significantly lower cost than the one presented in TAM 2021. Regarding minimum tonnage requirements that cannot be reconfigured in the short term, the disallowance should serve as an incentive for PacifiCorp to seek reductions in the minimum tonnage and more carefully examine its commitment to any such provisions in future CSAs. Additionally, it should give the Commission the opportunity to apply more scrutiny to CSA provisions that have historically dictated unit operations without having been subject to regulatory oversight.

B. Future TAM Oversight

Q. Do you have any recommendations that could improve the Commission's oversight of future TAM applications beyond 2021?

A. Yes. My recommendations pertain two key issues going forward: 1) Adjustments to PacifiCorp's modeling methodology for forecasting NPC in future years, and 2)

Commission review of future Coal Supply Agreements or modifications to existing agreements, and 3) Commission oversight of wholesale market participation that may be impacted by the TAM.

Q. What recommendations do you have regarding PacifiCorp's modeling methodology for forecasting NPC in future years?

A. There are three primary methodological changes that I would recommend the Commission require of PacifiCorp in future NPC forecasts that include production cost modeling efforts (e.g. via GRID). Specifically, I would recommend the following: 1) set the dispatch tier fuel prices equal to the costing tier prices, 2) remove arbitrary must run constraints at all plants and in all hours, 3) remove all minimum fuel burn constraints.

Q. Can you elaborate on each of these, starting with the dispatch tier and costing tier price assumptions?

A. Yes. First, the cost that GRID uses to dispatch the units should reflect the full price. If the CSA has multiple tiers, then the price of the first tier should be used (or a weighted average). Only in the case that optimal consumption under first tier pricing is higher than the first-tier volume, should GRID use second tier prices. If there are no multiple tiers, there is no reason for the costing tier to be different than the dispatch tier. This update should apply to all plants including ones with pre-existing CSAs.

Q. Going forward (i.e. for new or extended CSAs modeled in GRID), if the use of dispatch tier prices reflecting the full fuel cost leads to projected consumption below the minimum tonnage levels, should the OPUC allow the full recovery of those take or pay costs?

A. No, it should not. Without minimum tonnage considerations, the true least cost dispatch of PacifiCorp's fleet would lead to much lower generation from plants with these provisions. However, PacifiCorp itself negotiated these contracts and the minimum tonnage requirements based on an assumed level of dispatch that may have been too high when the CSA was signed. For this reason, these costs should not be immune to disallowance. They should be denied because PacifiCorp's decisions resulted in higher costs for its customers than would otherwise have occurred.

Q. Please elaborate on your recommendation to remove minimum burn constraints.

A. For new CSAs, including the recent Colstrip agreement, minimum burn constraints should be removed, and units should be dispatched based on contract prices for their full range of consumption (including levels below minimum tonnage). If the minimum take contract has been prudently designed, GRID will still dispatch the unit to consume it. If GRID does not dispatch the unit to fully consume the minimum tonnage, then the cost should simply be disallowed. It is upon PacifiCorp to only enter CSAs with economic and prudent minimum tonnage, and it should be held accountable if it fails to do so.

Q. Please elaborate on your recommendation to remove must run constraints.

A. When conducting production cost modeling for the NPC, PacifiCorp should allow economic cycling for all its units throughout the year. The updated GRID modeling, rid of all inappropriate constraints and input adjustments, should not only apply to the NPC forecast calculations, but also inform PacifiCorp's business plans and contract negotiations.

Q. What are some of the key factors that have led to PacifiCorp's expenditures on fuel (and subsequent requests for cost recovery through the TAM) which may be higher than other alternatives?

A. The most significant factor is the establishment of minimum tonnage requirements on coal contracts. Related factors include operating constraints such as minimum burn requirements or must-run requirements that may be imposed to ensure minimum take requirements are met.

Q. What is your recommendation for future TAM filings related PacifiCorp's "take or pay" or minimum tonnage contract provisions?

A. I recommend that in future these provisions be subject to Commission oversight if PacifiCorp intends to seek cost recovery for associated fuel costs from ratepayers. At a minimum, PacifiCorp should be required to inform the Commission any time that it executes a new CSA and what the key provisions of that agreement are. I recommend that the Commission direct PacifiCorp to provide information about the key provisions (including minimum take quantities) of any new, modified, or updated coal supply agreements within 30 days of executing the agreement.

Q. Are you recommending that the Commission preapprove any of PacifiCorp's CSAs?

A. No. I recognize that it is the Commission's general practice not to preapprove rate recovery of costs. As such I recommend that CSA terms be provided only as information as they are executed. Any prudency determinations to authorize cost recovery can be made at a later date. However, in addition to the CSA terms, the Commission should require PacifiCorp to provide a detailed justification for any minimum tonnage thresholds.

Q. Your testimony has revealed some inconsistencies between the planning and operations of PacifiCorp's system. How can the Commission improve the linkage between PacifiCorp's planning activities and its operations?

A. I recommend that the Commission direct PacifiCorp to include for review in the Integrated Resource Plan ("IRP") process the review of any new, modified, or updated coal supply agreements with minimum tonnage requirements if PacifiCorp intends to seek cost recovery from Oregon ratepayers.

Q. Do you have any recommendations regarding PacifiCorp's existing CSAs?

A. Yes. I recommend that the Commission direct PacifiCorp to review its coal contracts with renegotiation provisions and provide the Commission with a report analyzing whether such renegotiations would be in the best interest of Oregon ratepayers.

Q. What other oversight should the Commission consider regarding PacifiCorp's wholesale market activities?

A. I recommend that the Commission consider further investigation regarding PacifiCorp's wholesale market activities that depend upon generation resources where fuel costs are recovered through retail rates (e.g. TAM). This investigation should explore PacifiCorp's bidding practices to ensure that retail customers are not overly subsidizing wholesale sales through artificially low bid prices as described in my testimony.

Q. What other guidance could the Commission provide to ensure that PacifiCorp's wholesale market practices are in the best interest of Oregon ratepayers?

A. The Commission could provide direction that, if the Company seeks to recover any TAM costs that include an off-system sales component, then the company must report the following information for each hour of the sales period: market bid price ($/MWh), generation units in operation, generation unit production costs ($/MWh), total sales revenue ($), and total energy delivered (MWh). The Commission should then only allow PacifiCorp to recover fuel-related costs for generation during these hours if the market bid price was greater than or approximately equal to the production cost of the highest-cost unit.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

SIERRA CLUB EXHIBIT 101

Exhibit Accompanying the Opening Testimony of Ed Burgess

Curriculum Vitae of Ed Burgess

Edward Burgess

eburgess@strategen.com
941-266-0017

Overview

Ed Burgess is Senior Director of Strategen Consulting's Government and Utility Consulting Practice. His core expertise is in policy and regulation of the electric power sector at the state level, with a specialized focus on economic analysis, technical regulatory support, resource planning and procurement, utility rates, and policy & program design. Ed has served clients in the renewable energy, energy storage, electric vehicle, and energy efficiency industries, including several private companies, energy project developers, trade associations, utilities, government agencies, and foundations. His technical analysis has helped to shape state regulations and policies related to energy portfolio standards, distributed energy resources, rate design, resource planning and transmission/distribution system planning. Prior to joining Strategen, Ed played a lead role in two major initiatives at Arizona State University: The Utility of the Future Center and the Energy Policy Innovation Council where he conducted research and policy analysis for the Governor's Office of Energy Policy, the Department of Environmental Quality, and other major stakeholders in Arizona. Ed also worked as an independent consultant for Schlegel & Associates, providing technical analysis on demand-side management policies, and for Kris Mayes Law Firm providing regulatory support to the solar industry in the Southwest U.S.

Senior Director
AUG 2019 – Present
Director
JAN 2018 – AUG 2019
Senior Manager
JUL 2016 – DEC 2017
Manager
JUL 2015 – JUN 2016
Strategen Consulting – Berkeley, CA

Independent Consultant
NOV 2012 – JUL 2015
Schlegel & Associates – Phoenix, AZ
JUN 2012 – JUL 2015
Kris Mayes Law Firm – Phoenix, AZ

Project Manager & Researcher
JUN 2012 – JUL 2015
Arizona State University – Tempe, AZ

Instructor
JUN 2011 – MAY 2012
Arizona State University School of Sustainability – Tempe, AZ

Research Fellow
JUL 2007 – JUL 2009
Environmental Defense Fund – New York, NY

EDUCATION

PSM, Solar Energy Engineering and Commercialization
Arizona State University, 2012

MS, Sustainability
Arizona State University, 2011

BA, Chemistry
Princeton University, 2007

EXPERIENCE – 11 YEARS

Energy Resource Planning & Procurement
Utility Rates and Regulation
Cost Benefit Analysis
Avoided Cost and Cost Effectiveness
Energy Policy & Markets
Energy Product Development & Market Strategy
Stakeholder Engagement
Management Consulting

Selection of Relevant Projects at Strategen Consulting

Massachusetts Attorney General's Office

- Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years.
- Served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of the Consumer Advocate

- Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources.
- Developed a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

District of Columbia, Office of the People's Counsel

- Provided technical support and analysis on a utility proposed electric vehicle charging program
- Supported drafting comments on the Counsel's position in favor of a more customer-friendly approach to electric vehicle program implementation

North Carolina, Office of the Attorney General

- Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.

Maryland, Office of People's Counsel

- Provided technical support to the state's consumer advocate topics associated with the large PC44 grid modernization effort.
- Topics included electric vehicles, energy storage, distribution grid planning, and interconnection.

Arizona, Residential Utility Consumer Office (RUCO)

- Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
- Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
- Lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Portland General Electric

- Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
- Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
- Supported development of a competitive solicitation process for potential storage technology solution providers.

Xcel Energy

- Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

City and County of San Francisco

- Aided in evaluation of solar PV with battery storage as a solution for resilience of critical infrastructure.
- Provided technical economic assessment of opportunities for wholesale market participation as an added value for facilities installed.

University of California, San Diego

- Conducted economic analysis to help guide a multi-year research project on the use of advanced solar forecasting technology to improve integrated solar and energy storage.

University of Minnesota

- Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.

- Conducted study on the use of storage as an alternative to natural gas peaker.
- Presented workshop and study findings before the Minnesota Public Utilities Commission.

Arizona State University (ASU)/Arizona Department of Environmental Quality (ADEQ)

- Project manager for partnership between ASU/ADEQ to study compliance options for the state of Arizona to meet requirements of the EPA's Clean Power Plan (CPP).
- Completed a comprehensive study on the impact of CPP scenarios on the operation of the southwest power grid and cost to Arizona and Navajo Nation electricity customers.

Recent Publications

Edward Burgess, Ellen Zuckerman, and Jeff Schlegel, "Is the Duck Curve Eroding the Value of Energy Efficiency" Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2018 Summer Study on Energy Efficiency in Buildings, (pending).

Lon Huber, Ed Burgess, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future," (November 2016), Arizona Residential Utility Consumer Office, Arizona Corporation Commission, Docket No. E-00000Q-16-0289, https://www.strategen.com/s/Evolving-the-RPS-Whitepaper.pdf

Mark Higgins, Ed Burgess, and Bill Ehrlich, "Energy Storage Likely to Increase in Utility Resource Planning" Natural Gas and Electricity, Volume 32, Number 10 (May 2016).

Ellen Zuckerman, Edward Burgess, and Jeff Schlegel, "Are Recent Forays into Restructuring a Threat to Energy Efficiency?" Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2014 Summer Study on Energy Efficiency in Buildings, (August 2014) http://aceee.org/files/proceedings/2014/data/papers/6-1135.pdf#page=1.

Sonia Aggarwal and Edward Burgess, "Performance Based Models to Address Regulatory Challenges" The Electricity Journal (July 2014) http://www.sciencedirect.com/science/article/pii/S1040619014001389.

"Transmission and Renewable Energy Planning in California," prepared for the Western Governors Association, (November 2012) http://www.westgov.org/wieb/wrez/11-28-2012WREZca.pdf.

Edward Burgess and Petra Todorovich, "High-Speed Rail and Reducing Oil Dependence" in Transport Beyond Oil, Island Press (March 2013).

"On the nature of the dirty ice at the bottom of the GISP2 ice core," Earth & Planetary Science Letters (October 2010). http://www.sciencedirect.com/science/article/pii/S0012821X10006084

Selected Speaking Engagements

- California Energy Storage Alliance, Market Development Forum (February 2019)
- Rutgers University, Rutgers Energy Institute 2018 Annual Symposium (May 2018)
- Energy Storage North America (August 2017)
- MN Energy Storage Workshop (Sept 2016 & Jan 2017);
- Arizona Corporation Commission Peak Demand Workshop, (August 2016);
- Arizona Department of Environmental Quality, Clean Power Plan Technical Working Group, (May 2016);
- Energy Storage North America (2015);
- ASU Clean Power Workshop (February 2015);
- Western Interstate Energy Board Meeting (March 2014).

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

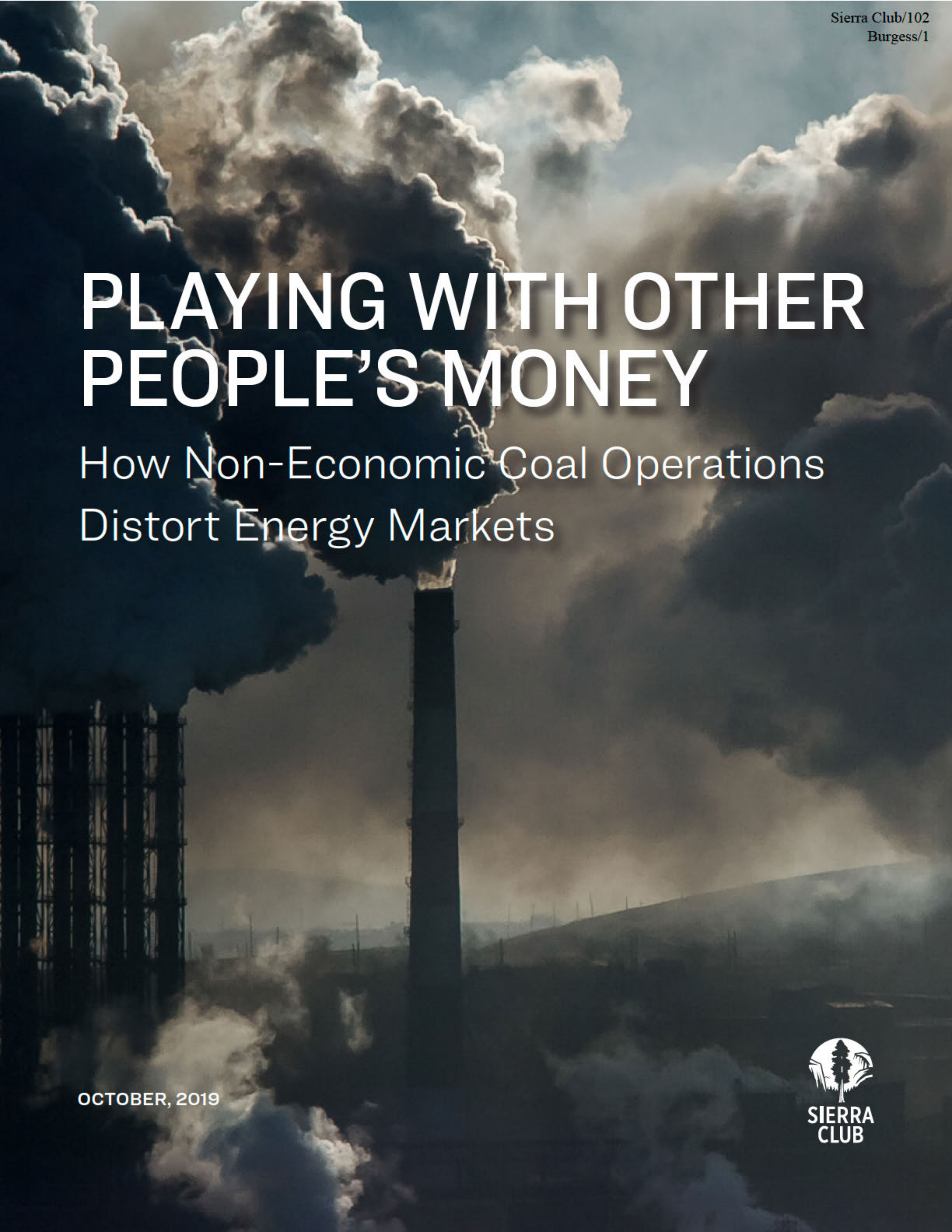
UE 375

SIERRA CLUB EXHIBIT 102

Exhibit Accompanying the Opening Testimony of Ed Burgess

Jeremy Fisher et al., *Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets*

Sierra Club/102
Burgess/1



PLAYING WITH OTHER PEOPLE'S MONEY

How Non-Economic Coal Operations Distort Energy Markets

OCTOBER, 2019

SIERRA CLUB

AUTHORS & ACKNOWLEDGEMENTS

Authors
Jeremy Fisher, *jeremy.fisher@sierraclub.org*
Al Armendariz
Matthew Miller
Brendan Pierpont
Casey Roberts
Josh Smith
Greg Wannier

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EXECUTIVE SUMMARY

Regional energy markets in the U.S. were designed to foster competition amongst power plants, in order to save electricity consumers money through efficient operation. There is growing evidence, however, that in several of these markets rate-regulated utilities are operating coal units out of merit for extended periods, rather than allowing the markets to determine when these units are competitive. The objective of this research was to examine the extent to which electric utilities operate coal units out of merit, and to quantify the impact of non-economic dispatch on consumers and merchant power generators.

We conducted several analyses examining the extent and consumer impacts of "self-scheduling" coal plants in the electric markets regions of MISO, SPP, ERCOT, and PJM from 2014 to 2017. Our analyses demonstrated that, in periods when energy market prices are low, coal plants owned by regulated, vertically integrated utilities are systematically operating coal plants out of merit, to an extent not seen in merchant-owned coal plants. The insensitivity of regulated coal plants to non-economic dispatch through extended periods of low market prices, and the clear actions by merchant coal plants to avoid non-economic dispatch was apparent in each of the market regions we examined. For example, within PJM, where most power units are merchants (i.e. unregulated), coal units generally operate in accordance with market prices. The few regulated coal units, owned by Dominion or American Electric Power (AEP), demonstrated a markedly different behavior, operating in far more hours than warranted by market prices.

Overall, we estimate that captive ratepayers of regulated utility coal plants paid $3.5 billion more for energy from 2015-2017 due to non-economic dispatch relative to the potential procurement of energy and capacity on the market. Accounting for the costs of fixed operations and maintenance (O&M) and revenues from capacity markets in MISO and PJM, **we estimate that coal plants with negative net revenue lost over $3.8 billion in 2015-2017, losses that are likely being made whole via state ratemaking.** The vast majority of the losses (79-87%, by year) were incurred at coal plants owned by regulated utilities.

The non-economic operation of a large number of units renders it difficult to determine what an alternative outcome could have looked like if all units had operated in merit order. Specifically, when units start to operate economically, it may change market prices and have interactive effects with other displaceable generators. To assess the practicality of units achieving economic dispatch, and the impact on both other dispatchable resources and market prices, Sierra Club retained Synapse Energy Economics to conduct intensive system modeling. Synapse ran unit-specific chronological dispatch modeling of MISO with transmission and operational constraints. The purpose was to compare actual MISO operations in 2017 to what would have happened had units dispatched economically.

The results of our modeling demonstrated that economic dispatch of MISO's coal units in 2017 was feasible, and would have resulted in less coal generation, lower system costs, and higher market revenues. If coal units had dispatched economically in 2017, rather than self-scheduling, generation from coal units would have fallen by about 10 percent, from about 324 TWh in our base case (representing actual 2017 conditions) to 293 TWh under economic dispatch, a reduction of 31 TWh. Consistent with our non-modeled findings, the reduction in coal **generation from economic dispatch is almost entirely (93%) attributable to coal units owned by regulated utilities.**

Operating out of merit, or dispatching more often than is dictated by market conditions, increases production costs; and economically dispatching coal drives down total production costs. When non-economic units are no longer forced online, they are replaced by more efficient and lower-marginal-cost resources. Our modeling indicates that the total production cost of coal-burning generators in MISO would have dropped from $10.07 billion to $8.78 billion in 2017, a savings of $1.29 billion in that year alone. The benefit of this production cost savings would likely be allocated almost entirely to the customers of regulated utilities who today pay for the operations of non-economically operated coal via state ratemaking processes.

Finally, **our modeling shows that operating out of merit likely suppresses market prices.** In contrast, economic dispatch lifts market prices, and increases revenues for efficient generators. We assess that across all nine modeled MISO regions, the median hourly market price would have increased by about $7.7/MWh, or around 30%, if coal units had economically dispatched in 2017. The increase in market prices is consistent across both low- and high-cost hours.

Utilities have sought to explain that they operate out of merit due to constraints faced by coal units, including slow ramp rates, large fixed-price fuel contracts, and thermal stresses incurred during startup. Nonetheless, the substantially different behavior of regulated merchant coal plants suggests that the decision to operate consistently out of merit order is not operational, but rather is related to the way that regulated coal plants make revenue. In particular, regulated coal units recoup fuel and operational costs directly from ratepayers, rather than through market revenues. This decoupling makes it harder for regulators to assess if a coal unit has operated competitively. In many states, fuel and operations costs are passed through *pro-forma* "adjustment" dockets, which further decouple the full costs of operation from dispatch decisions.

Captive customers of vertically integrated utilities that are part of multi-state energy markets may be paying more for electricity generated by coal units owned by their utility than could reasonably be obtained through market energy and capacity, particularly during periods of sustained low market energy prices. Those utility customers pay for expenses incurred when the coal plants were uneconomic and less-expensive power was available but not obtained by the utility.

There are concrete steps that could be taken by state commissions and others to better protect electric consumers from the uneconomic consequences of generation out of merit and excessive self-scheduling:

- **Commissions and consumer advocates** should examine the self-commitment and self-scheduling practices of regulated utility coal-burning power plants in market regions through investigations, expanded fuel or rate case dockets, or during resource planning reviews;
- **Commissions** should examine the current real and implied incentives driving non-economic dispatch, and consider alternative positive and negative incentive structures to ensure regulated coal plant operators dispatch competitively, including the potential disallowance of operational costs in excess of market necessity;
- **Utilities,** in the absence of a rigorous multi-day market, should develop a consistent and transparent set of practices for avoiding operations and commitment during periods of persistently low market prices;
- **Market monitors** should rigorously examine the behavior and bids of slow-ramping, coal-burning units to ensure that market costs are not being inappropriately depressed through the non-economic actions; and
- **ISOs and RTOs** should consider more advanced forward markets that send a clear commitment-relevant market signal to better inform utilities' decision making, and raise the barrier to self-commitment.

Improved dispatch practice would reduce customer costs, improve market revenues for efficient generators and renewable energy operators, and substantially reduce emissions. Centralized energy markets in the US have been designed — and touted for — their ability to ensure energy is used efficiently and competitively, but most market assessments seek to review if participants are inappropriately gaming the market for increased revenues. In this case, the markets should also work to ensure that regulated thermal plants aren't seeking to increase revenues from captive ratepayers at the expense of market prices and ratepayer costs.

1 INTRODUCTION

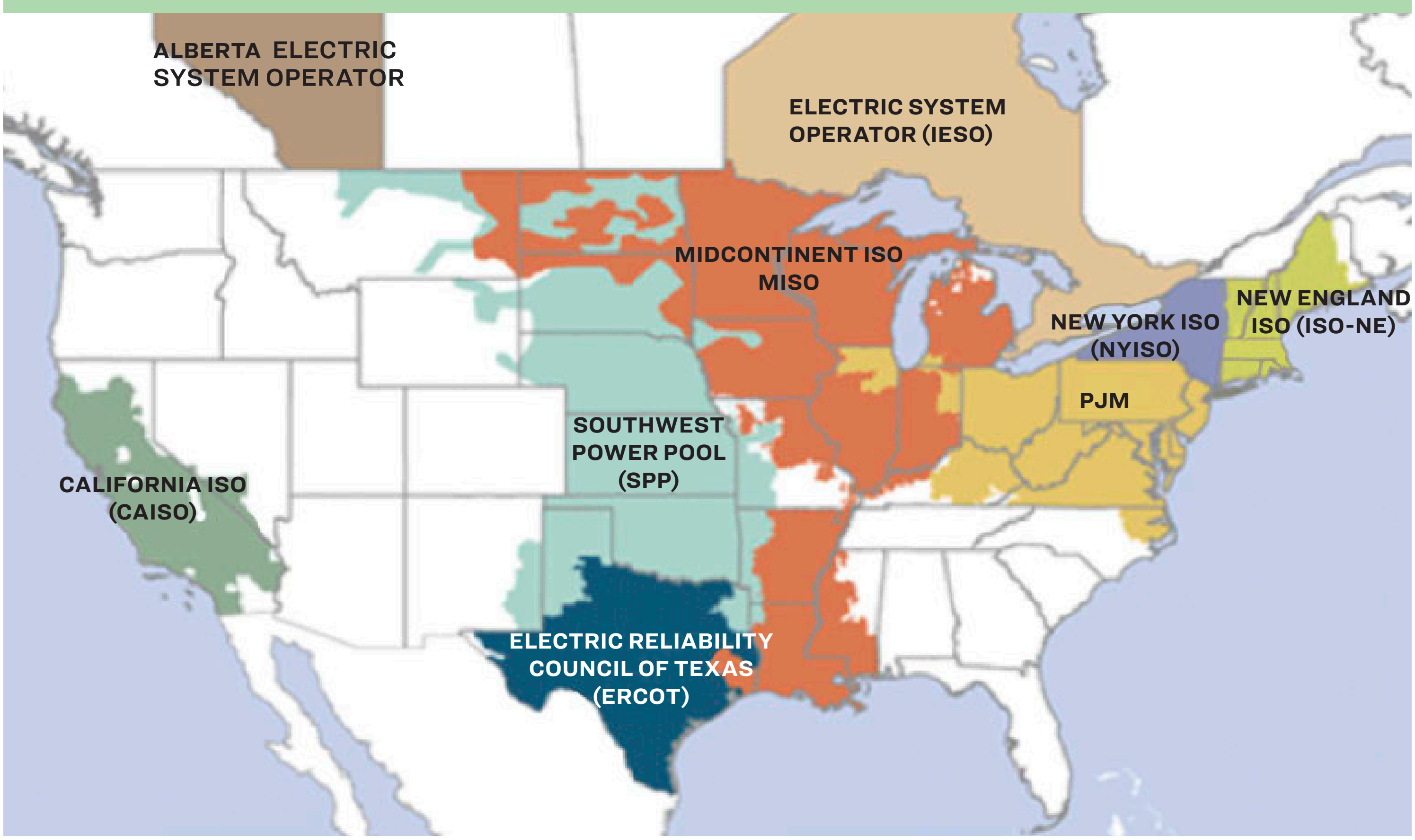
Almost two-thirds of all electricity generation, and just over two-thirds of coal-fired generation, in the United States is dispatched through one of seven centralized energy markets.[1] These markets are designed to provide customers with the lowest-cost reliable mix of generation, capacity, and other services. At its simplest level, the market structure is intended to minimize the short-run production costs needed to meet demand: the markets are designed to allow low-cost generators to compete, while coordinating the efficient operation of generators. There are seven energy market regions in the United States (Figure 1), called Independent System Operators ("ISO") or Regional Transmission Organizations ("RTO"). Each ISO/RTO (hereinafter simply "RTO") coordinates transmission, short-term reliability, and the operation of the grid.

Today, each RTO in the United States operates a centralized energy market, serving essentially as a clearinghouse for generation bids to meet demand requirements. Load-serving utilities submit their demand requirements on a day-ahead basis, and the generators competing to serve that energy demand bid their generation into the market, typically at the individual generator's cost of production. The RTO aggregates the bids and determines, in conjunction with operational constraints, which generators should operate the next day, when, and at what levels. The RTOs also operate a real-time balancing market to respond to real-time demand changes and generating unit availability. In general, RTOs select bids on the basis of production cost—which is to say, at short-term variable cost, typically comprised of fuel costs as well as variable operations and maintenance ("O&M") costs. The RTO then creates a "merit order" supply curve of least-cost to highest-cost generators, and generally first calls upon the lesser-cost generators to satisfy energy needs. There are important exceptions, however, to that economically efficient order of dispatch.

In 2017, Sierra Club conducted preliminary research finding that coal-burning power plants in the central United States were likely operating more often than was warranted economically, and were acting outside of reasonable expectations for generators in a centralized energy market.

Here we build on that research to further examine the impact of non-economic coal-fired generation on cost and market prices. The objective of this research was to examine the extent of the over-dispatching problem by electric utilities and to quantify the impact of over-dispatching on consumers and merchant power generators.

Figure 1 Map of North American ISOs and RTOs.[2]



2 REGULATED UTILITIES AND THE SELF-SCHEDULING LOOPHOLE

Vertically integrated utilities are generally rate-regulated utilities that own, and charge their customers for, generation, transmission, and distribution services, rather than paying a wholesale cost for transmission or generation services. If a "regulated" utility[3] owns a power plant, the customers of that regulated utility pay for the fuel and O&M costs of that power plant.

In contrast, in regions of the country that have undergone "restructuring," utilities purchase energy from a centralized market. In these regions, the vast majority of generation is owned by independent power producers, or merchant generators. This is the case in The Electric Reliability Council of Texas ("ERCOT"), PJM Interconnection ("PJM"), New York ISO ("NYISO"), and ISO New England ("ISO-NE"). In those regions, utilities generally do not own generation stations.

However, some generators in these regions, and the majority of the generators in the market regions of Midcontinent ISO ("MISO") and the Southwest Power Pool ("SPP") are owned by regulated utilities. In these cases, the generators still bid into the market, but the costs of operation are paid for by ratepayers.

What is the connection between a regulated generator that bids into a competitive energy market, and yet has its production costs paid for by ratepayers?

In many circumstances, the generator still is expected to act as a market participant, but one backed by ratepayers rather than a private owner: the ratepayers pay for the costs of the generator, and in return are credited market revenues received by the generator. In such a set-up, the regulated generation owner is effectively participating in these regional RTO markets on behalf of its ratepayers.

If it costs a regulated generator less to produce electricity than to purchase energy at the market price, and the generator is economically dispatched, the retail customers that pay for the generator's operations could see a net benefit in the form of reduced rates relative to customers of utilities that purchase market energy to serve customers' energy demand.

On the other hand, **if it costs a regulated generator more to produce energy than the market, or if the generator is not economically** dispatched (*i.e.*, operates substantially out of merit order), **ratepayers can end up paying substantially more than the cost of market energy and capacity** — clearly an inefficient outcome**.**

How and why does a generator operate out of merit order in a competitive market?

RTOs almost always provide opportunities for generators to provide generation "out of merit," — or out of accordance with strictly competitive behavior— and there are reasons that a generator should be allowed to do so. In the simplest example, a generator may need to test equipment. In such a case, a unit might alert the RTO that it intends to operate, regardless of cost relative to alternatives.

As a general matter, there are three ways that a generator can operate out of merit order. It can indicate to the RTO that it will "self-schedule," it can indicate that it will "self-commit," or it can submit a bid below its cost of production.

- ***Self-scheduling:*** In self-scheduling, a generator identifies the hours in which it will operate, and the level at which it will provide generation. When a generator announces that it will self-schedule, it is included in the supply curve as a zero-cost bid, but (as occurs with every other generation that clears) it will receive prevailing market prices.
- ***Self-commitment:*** When a generator elects to self-commit, it guarantees that it will operate at its "minimum loading," *i.e.*, the lowest level of generation it can provide, often 25 to 50 percent of its nameplate capacity.[4] A unit might self-commit to ensure that it is online, and allow the RTO to dispatch its remaining capacity economically. As in self-scheduling, the minimum loading of the power plant is included in the supply curve as a zero-cost bid.
- ***Bid below production cost:*** A generator can theoretically provide a bid to provide energy well below its actual cost of production. Such a low bid may effectively guarantee that the unit will clear the market.

Theoretically, regulated generators should seek to dispatch economically, based on their cost of production, in order to reduce costs to ratepayers, subject to reliability considerations. This principle applies regardless of whether a generator resides in a wholesale energy market, or not. Our research shows, however, that regulated generators in market regions operate far more than warranted by during extended periods of lower market prices—*i.e.*, they operate regularly out of merit order. Moreover, this pattern cannot be explained entirely by operational constraints.

Why would a regulated coal generator seek to operate out of merit and more often than dictated by operational necessity?

In general, a perverse outcome is made possible because regulated generators are able to recover production costs through captive ratepayers, in contrast to merchant generators that must recover all costs through their revenues from a competitive marketplace. And since regulated utilities do not generally report the net market gains or losses of individual generators (or even their whole generation system relative to market prices) to regulators, it is difficult for regulators to discern whether this inefficient, ratepayer-harming phenomenon is in fact occurring.

One hypothesis is that it is difficult to justify continued investment in a plant which, originally built for "baseload" output, now operates only as a seasonal "peaker". In general, regulators assume that generators operating in market regions are dispatched economically, follow market signals, and consume only as much fuel as necessary. In fact, in many states, fuel costs are accepted into rates on a *pro forma* basis in fuel-adjustment proceedings.

This lack of scrutiny enables regulated generators to operate more than economically warranted, and at substantial cost to captive ratepayers. In effect, those retail customers are effectively subsidizing the generator's unnecessary uneconomic operations in the wholesale market. That is, the ratepayers are essentially paying, through mandated retail rates to their regulated utility, a cost above that which they would paid if the utility had instead chosen not to self-commit, and simply procured power for its customers from the wholesale market.

Here, we explore evidence that regulated coal plant operators in all market regions have operated coal plants out of merit, without apparent justification or detailed review, for years. This behavior becomes most apparent when market prices fall: merchant generators curtail operations while regulated generators continue operations. We show that these non-economic decisions have unnecessarily driven up costs to captive ratepayers of non-economic coal plants, increased emissions from non-economic coal plants, and driven down revenues to independent generators, renewable energy producers, and more economically efficient regulated generators. We also delve into the reasons given by utilities for operating coal units out of merit order, and propose a series of solutions to drive a more efficient market with better transparency.

3 COAL-BURNING UNITS IN MARKET REGIONS OPERATE NON-ECONOMICALLY

Prior research conducted independently by Sierra Club[5] and Union of Concerned Scientists (UCS)[6] demonstrated that units in SPP operate outside of merit order — meaning, again, that they dispatch more often than would be indicated by market prices, and would therefore likely lose substantial net revenue if they were merchant operators. In early 2018, the SPP Market Monitor, an independent entity charged with ensuring efficient and fair operation of the energy market, suggested that persistent negative pricing in the market could be attributed both to a large penetration of must-take wind and to excessive self-scheduling by existing coal units.[7] And in mid-2018, the Greater Springfield Chamber of Commerce released a report assessing that the City of Springfield's City Water, Light and Power ("CWLP") "operated generation resources in a non-economical manner." Specifically, this report found that "the full Marginal Cost of Generation for CWLP's generation resources was higher than the clearing market price for electricity in *all but 1.9% of the hours in 2016*."[8]

Here, we confirm that hypothesis and demonstrate that numerous coal-burning power plants in market regions operate non-economically, primarily by committing to operate during extended periods of low market prices—to a degree that is not justified or overcome by revenues earned during periods of high market prices.

Case Study: Gibson 5 (Indiana)

An example of dispatch behavior and market prices is shown in Figure 2 (2014) and Figure 3 (2016) for Gibson 5, a 665 MW coal unit owned by Duke Indiana.

The figure shows market energy prices by month (2nd and 3rd quartile, or the 25th to 75th percentile range of energy prices) compared against an estimated production cost from public data sources. Above the price comparison, we show the capacity factor of the plant during the same months.

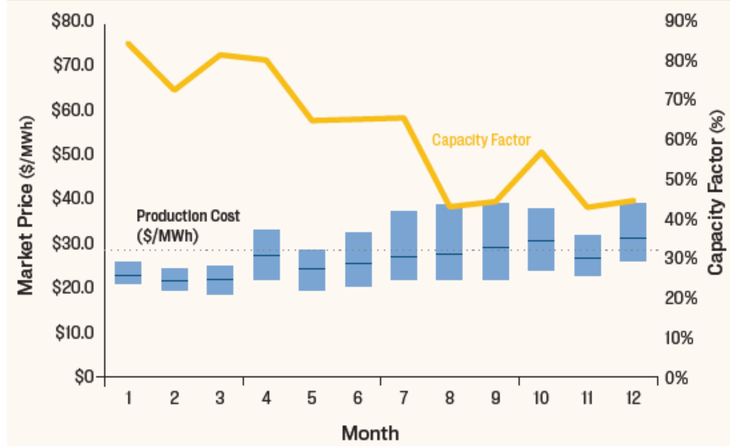
In early 2014, market energy prices in Indiana were high — from \$38 to \$64/MWh between January and May,[9] comfortably above the coal plant's estimated production cost of \$32/MWh.[10] However, after June 2014, median energy market prices fell to the plant's production cost of \$32/MWh and stayed near that level.

As a consequence, the unit began ramping on nearly a daily basis, seeking to avoid lower cost hours through cycling, but it didn't actually come offline — in other words, it operated nearly every day, even when market prices were substantially below the cost of operation. Despite brief market price increases late in the year, we estimate that Gibson 5 generated almost no net energy market revenue in the second half of 2014. And while Gibson 5 cleared $42 million in net market energy revenues in 2014, 70% of that was in the first three months of the year. Coal plant cycling (i.e. seeking to generate less energy during off-peak hours) is discussed in more depth in **Appendix A.**

Figure 2 Range of market prices and production cost (left axis) and capacity factor (right axis) for Gibson 5 (Indiana) in 2014.[11] Range of market prices represents monthly 25th to 75th percentiles, median shown in solid line.

In 2016, market prices in MISO's Indiana hub were much lower than the estimated production cost of Gibson 5 — even the highest quartile of market prices didn't exceed Gibson 5's $28.4/MWh production costs in January, February, March, or May (see Figure 3, below). And yet Gibson 5 dispatched at an average 75% capacity factor for the first half of the year, and thus operated at a net energy market loss in those months. We estimate that from January through March, Gibson 5 lost $5.3 million on an operational margin or net energy revenue. And while energy market prices climbed modestly in late spring (April through June), they still remained below Gibson's production cost. So while Gibson held a 70% capacity factor through the late spring, it made zero net energy market revenue. The profitability of Gibson 5 only improved in the second half of the year, due to two separate factors: (a) market prices increased to just above the unit's production cost, and (b) the unit began turning off for long stretches of time.

Figure 3 Range of market prices and production cost (left axis) and capacity factor (right axis) for Gibson 5 (Indiana) in 2016.[12] Range of market prices represents monthly 25th to 75th percentiles, median shown in solid line.



We estimate that Gibson 5 cleared about $8.6 million in net energy revenue in the second half of 2016, and just barely cleared $2.8 million in net energy revenues for the year, or $4.6/kW-yr.

Is $4.6/kW-yr in net energy revenues a reasonable revenue stream for a competitive coal plant? In addition to the variable costs of operation, plants also incur fixed costs, such as labor, maintenance, and taxes. And plants in MISO have the opportunity to sell capacity on a voluntary market as a "fixed" revenue stream. The Energy Information Administration ("EIA") estimates that conventional coal plants incur on the order of $42/kW-yr in fixed operations and maintenance ("O&M"). Accounting for MISO's capacity market and the prevailing price of capacity in 2016, we assess that if the utility were operating instead as a merchant, this coal unit would have *lost* about $8.5 million in 2016, after accounting for fixed O&M and market capacity value. Gibson 5 therefore likely cost ratepayers far more to operate in 2016 than if Duke Indiana had purchased energy and capacity from the wholesale market.

Why would a coal operator, legally obligated to provide least-cost service to ratepayers (in the case of a regulated utility), elect to dispatch a coal plant non-economically?

In a recent investigation into non-economic commitment and dispatch in Missouri,[13] utilities described four fundamental reasons that they commit units beyond a market-competitive level of dispatch:

- ***Fixed fuel contracts:*** Fuel contract with a "must take" provision may drive a unit to operate out of merit order to consume a contractual fuel obligation and avoid accumulating an unmanageable inventory on-site. A coal plant which has contracted for more fuel than warranted by energy market prices will incur net market losses.

- ***Preventing thermal cycles:*** Many coal plants, in particular older and less efficient models, require substantial ramp times from a cold start to a minimum operational level, and can incur substantial thermal wear during startup and shutdown periods.[14] Preventing a thermal cycle (*i.e.*, shutting down for a short period of time) is only warranted if the cost of the incremental cycle exceeds the revenues lost by operating through a low market price period. Continuously operating without such an explicit calculation may result in substantial net market losses.
- ***Compliance and equipment testing:*** Coal plant operators occasionally test systems during times of otherwise non-economic dispatch.
- ***Lack of a multi-day market signal:*** Today, no centralized market operates longer than a day-ahead market for energy, meaning that a plant is only provided a 24-hour signal that it is required or not. A plant with a slow ramp, long minimum downtime or uptime, or high cycling cost may require a multi-day signal to capture its runtime constraints.

A private or merchant coal plant owner cannot afford to incur ongoing market losses — except in rare circumstances, the vast majority of revenue for a merchant coal plant is derived from energy (and capacity) market sales,[15] and incurring ongoing losses is not a pathway to profitability.[16] Merchant coal plant owners are compelled to cover all costs (including fuel, variable and fixed O&M, emissions costs, and ongoing capital) with market-based revenues, regulated coal owners are not held to the same requirements. Instead, the fuel and O&M costs of regulated coal plants are passed through to ratepayers, and it is often up to a regulator (or other oversight entity) to assess if a coal plant has provided a net benefit to ratepayers.

There are, however, other reasons that a regulated coal plant might seek to operate non-economically or self-schedule that are not fundamental operational considerations:

- ***Perception of use and usefulness:*** A coal plant operating at a high capacity factor, irrespective of economics, can lend a perception that the plant is a meaningful contributor to customer demands, and is therefore providing useful service. By contrast, it is difficult to justify continued investment in coal plants that, although built as "baseload" facilities, now operate as peakers on a seasonal basis. This distinction is critical for investor-owned utilities, who in many cases hold substantial remaining debt in coal plants, and who rely on public utility commissions to continue to authorize generous rates of return, as well as any undepreciated initial capital investment on existing coal plant. A utility commission faced with a coal plant operating at very low capacity factors might legitimately challenge the value of a low-dispatch coal plant. By maintaining a high capacity factor for a non-economic unit, a utility can create an illusion of economic value, even if it is unwarranted. For example, a recent rate recovery case in Virginia touted the high capacity factors, rather than the fundamental economics, of a utility's coal units as justification for the value of the units.[17]
- ***Perception of need to self-supply:*** Centralized energy markets (RTOs) in the United States also take on the roles and responsibilities of reliability coordinators and balancing authorities. However, some regulated utilities still self-schedule with a claim that a plant might be needed for reliability, even if the RTO has not identified a near-term need for that plant.[18]
- ***Revenue tied to off-system sales:*** While these agreements are increasingly rare, some utilities are authorized to retain (for shareholders) a fraction of revenue from off-system sales. A utility may have a strong incentive to operate a plant out of merit order with the expectation of passing through excess fuel and O&M costs while collecting excess off-system sales revenue. A profit-seeking utility could seek, for example, to allocate as much cost to a fixed category (*i.e.* a long-term coal fuel contract) as feasible to ensure substantial off-system sales at a low variable cost, and collect for excess revenues for shareholders, while allocating the fixed costs to ratepayers.
- ***Contracts tied to certain plant operations:*** Some utilities and generation and transmission companies ("G&Ts") serve generation to smaller cooperative or municipal utilities through "full requirements" contracts. In some cases, these contracts may specify that the generation be provided by a certain plant (rather than by market energy procurement), or allow the serving utility to specify the plant which provides generation. In such cases, a utility might be incentivized to run their own plant to serve a full requirements contract rather than procuring market energy on behalf of their wholesale customer.

If it were the case that all coal operators — both regulated and merchant — were observing purely operational reasons for self-scheduling, we would expect both regulated and merchant plants to act equally optimally, or sub-optimally. If, in fact, regulated coal plants observe a different set of rules or reasons to operate out of merit order, we would expect to observe separable behavior.

4 MERCHANT OPERATORS OF COAL-BURNING UNITS DISPLAY BETTER MARKET BEHAVIOR THAN REGULATED UTILITIES

In 2018, Bloomberg New Energy Finance ("BNEF") published research finding that about half of US coal generators had negative long-run operating margins from 2012-2017 relative to market prices, with the vast majority (130 GW of 135 GW) of coal units with negative margins owned by regulated utilities.[19] They further point out that "half of these 'uneconomic' coal plants are located in vertically integrated, regulated balancing authorities; [but] the other half exist within liberalized markets"—*i.e.*, ISO/RTOs with centralized energy markets.[20] BNEF notes that "throughout the U.S., regulated plants are much more likely than IPPs [independent power producers] to enjoy . . . protection against power market signals."[21]

We compared the dispatch of coal plants against market prices for regulated and merchant plants in four market regions (PJM, MISO, SPP, and ERCOT[22]) and found that, as a general matter, merchant coal plant operators hew closer to market-based paradigms than regulated utilities. Later in our paper, we seek to observe how one market region, MISO, would have looked if units dispatched closer to optimal in a historic year. However, for the purposes of assessing historic behavior across a wider swath of units, we can compare actual operations against "perfect," or optimal, dispatch.[23]

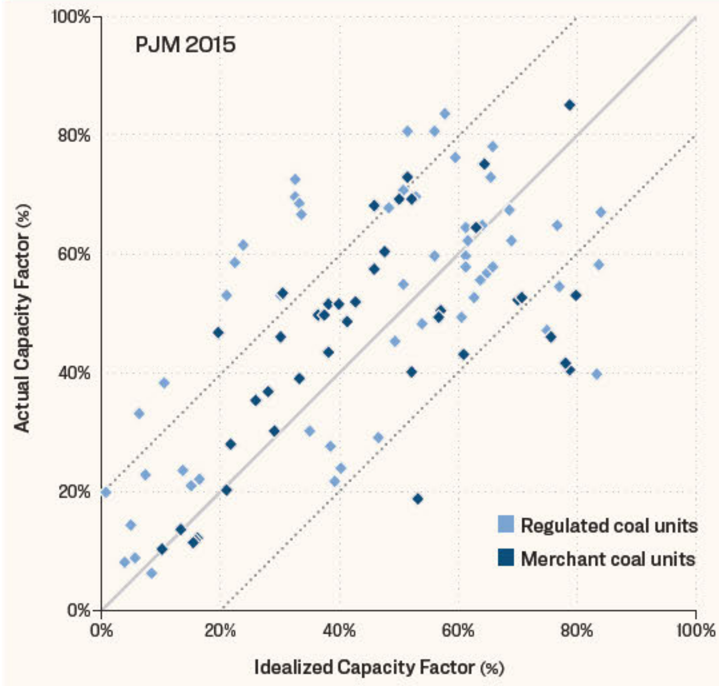
Using optimal, or "perfect," economic dispatch as a benchmark, we observed that merchant coal units in market regions are generally better aligned with market prices than regulated coal units in those same regions. In addition, under falling market prices, merchant generators dispatch downward (rationally), while regulated coal units do not, or dispatch downward far less.

Figure 4, below, compares the dispatch behavior of both merchant (shaded gray) and regulated coal units (shaded black) in PJM relative to optimal dispatch.[24] For illustrative purposes, a zone is defined around the 1:1 line representing dispatch within ±20% of the 1:1 line.[25]

A marker on or near the 1:1 line (*i.e.* within the ±20% zone) indicates that a unit should have had a certain capacity factor during the year, and hewed relatively closely to its expected outcome. Units that fall closer to the 1:1 line have generally preserved more market value in that year (or lost less relative to market prices).

A marker above the line indicates that a unit was operated more often than indicated by market prices (*i.e.* out of merit order more often than expected, relative to the ideal). A marker below the line indicates that a unit under-dispatched in 2015, relative to the optimal or idealized case.

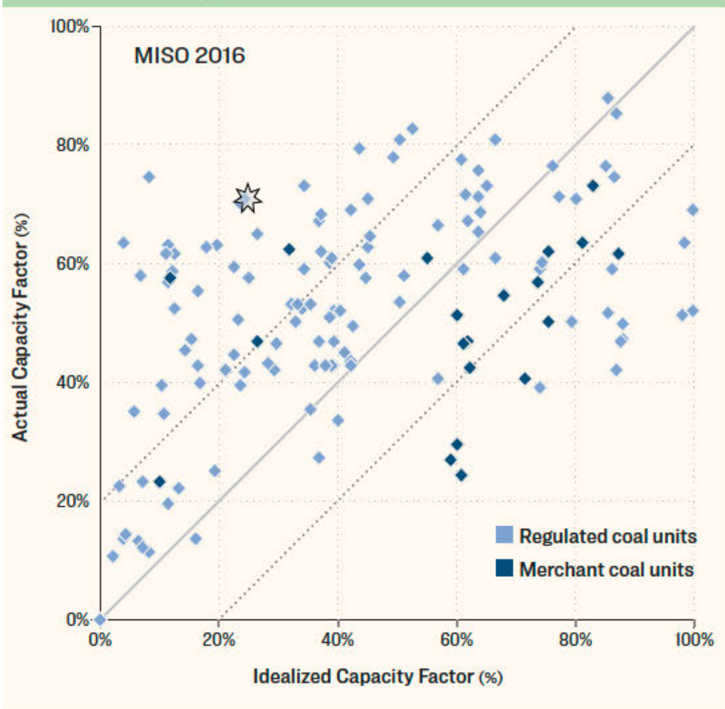
Figure 4 Actual capacity factor for PJM coal units in 2015 plotted against market-based "ideal" capacity factor. Regulated coal units shaded light blue, merchant units shaded dark blue.



We see here that the majority of coal-burning units in PJM in 2015 fell within ±20% of their optimal dispatch on a capacity factor basis. There are a few notable exceptions, however, almost all of which are regulated utilities (*i.e.* shaded black). Almost every unit that operated more than expected based on market prices is a regulated plant, the majority of which are owned by either Dominion or American Electric Power ("AEP").

The pattern of regulated utilities acting outside of market conditions is even more apparent in MISO, as shown in Figure 5, below. As a whole, many coal-burning units in MISO do not demonstrate economic dispatch. In fact, a large fraction of MISO coal units fall in the upper quadrant, indicating substantially more generation than merited by market prices. For example, there is a large cohort of units that would be predicted to have an idealized capacity factor of 20% or below which ran at capacity factors of 40-80%. Like PJM, regulated utilities are shaded black in this representation. Almost all of the coal-burning plants which operated out of merit in MISO in 2016 belong to regulated utilities.

Figure 5 Actual capacity factor for MISO coal units in 2016 plotted against market-based "ideal" capacity factor. Regulated coal units shaded light blue, merchant units shaded dark blue. Star identifies Edgewater Unit 5 in Wisconsin.

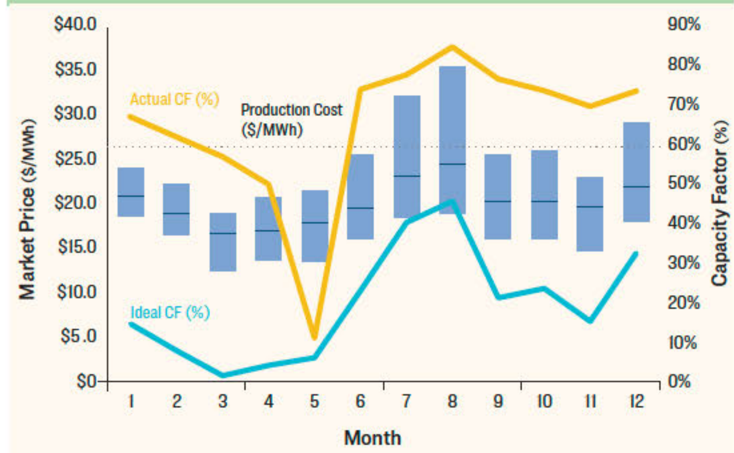


Case Example: Edgewater Unit 5 (Wisconsin)

Let us consider what is actually happening with individual units that operated more than could be justified by market prices in MISO in 2016. The star in Figure 5 identifies an example plant, Edgewater Unit 5, owned by Wisconsin Energy and Light. According to this assessment, it should have had a capacity factor in 2016 around 18%. Instead, it operated at a 63% capacity factor.

Figure 6 below shows the actual operations of Edgewater 5 against its idealized capacity factor on a month-by-month basis, superimposed on market prices (2nd and 3rd quartile, and median). It is notable that the $26.2/MWh production

Figure 6 Production cost and market price at Edgewater Unit 5 (Wisconsin) in 2016, and actual and idealized capacity factors for the unit.

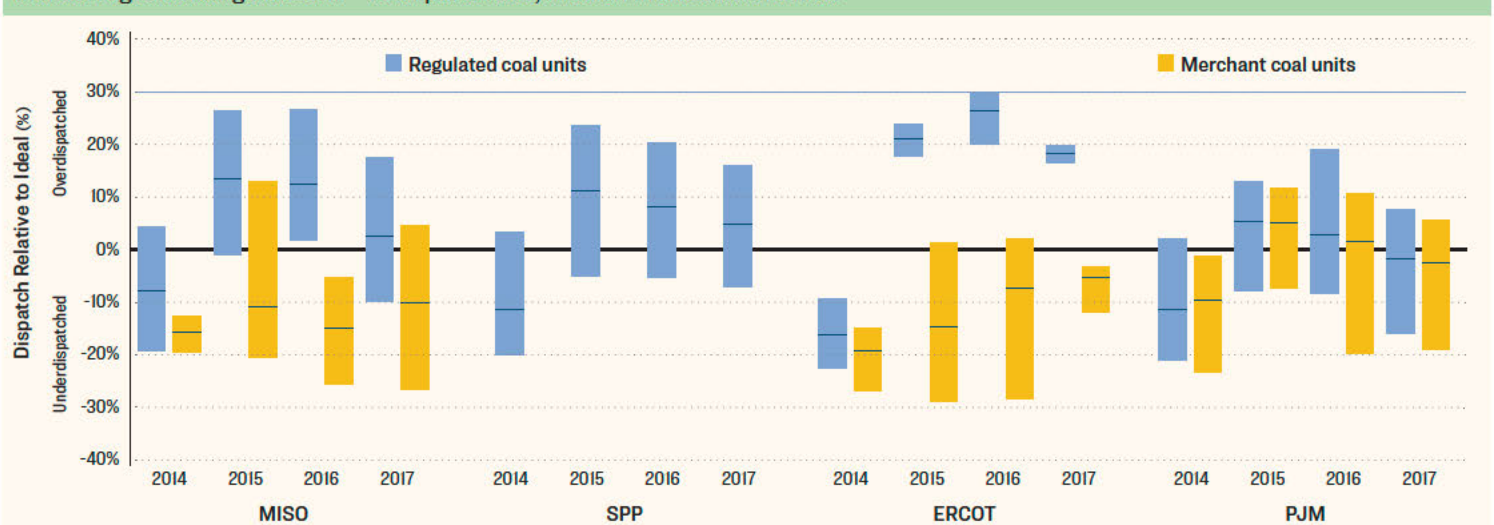


cost of Edgewater 5 remains above even the 75th percentile of market prices in every month but July, August and December. Consequently, the model predicts a dispatch of less than 30% in all but those three peak months. Idealized dispatch never rises above 50% in any given month.

In contrast, Edgewater 5 had above a 50% capacity factor in every month but April and May, when the unit was taken offline to tie in a new scrubber.[26] As a consequence, we assess that Edgewater 5 lost on the order of $8.3 million in net energy market revenues alone in 2016. That loss, together with fixed O&M charges, was covered by captured utility ratepayers, on top of what all ratepayers across the multistate region were normally charged for electricity.

If we look across regions and years, a few patterns emerge that suggest substantially different behavior between regulated and merchant coal. Figure 7, below, shows the range of the deviation of dispatch of coal units relative to the economic case from 2014 to 2017 in MISO, SPP, ERCOT and PJM. The size of each bar represents the range of dispatch

Figure 7 Range of dispatch of regulated (blue) and merchant coal units (yellow) relative to ideal, 2014-2017 in various US energy market regions. Range is 25th – 75th percentile, median marked with a line.



relative to the economic case: bars with medians near zero indicate that the median coal unit had dispatch near the economically optimal case. Conversely, bars that are entirely above or below the line suggest systematic over or under dispatch.

In 2014, most coal units in MISO, SPP, ERCOT and PJM dispatched *less* than expected, given market prices. A closer inspection of the data, however, shows that energy market prices in 2014 were relatively high, calling for a median optimal output of 75% capacity factor in MISO and up to a 96% capacity factor in ERCOT. Units with extended outages (possibly to tie in environmental controls), maintenance outages or faults, or simply an inability to ramp quickly enough to hit peak market prices, systemically dispatched less than might have been warranted by market prices.

In 2015, market prices fell substantially. In all of the regions analyzed here, the average all-hours price fell by about 30% (from $39.7 to $28.6/MWh in MISO, and from $51.0 to $35.8/MWh in PJM). In many cases, the average market price of energy fell below the production cost of coal generation, which should have driven down the economic dispatch of these units. Notably, in MISO in 2015, merchant coal generators were able to generally maintain a dispatch at or below optimal levels, while regulated coal units did not. In MISO, SPP, and ERCOT, regulated coal units operated out of merit in 2015, 2016, and 2017.

In PJM, both merchant and regulated coal units hewed to expected market behavior as a whole, with the exception of specific utilities discussed earlier.

5 MANY REGULATED UTILITY COAL PLANTS ARE UNECONOMIC IN MARKET REGIONS

We estimate that in the four market regions studied here (MISO, SPP, ERCOT, and PJM), regulated coal plants with negative net energy margins performed worse than the energy market by $1.5 billion from 2015 to 2017 (see Table 1). In total, between 28 and 33 GW of coal capacity incurred net energy market losses in those three years, the vast majority of which (77-84%) were regulated plants. MISO accounted for the single highest number of non-economically dispatched coal-burning power plants, with plants losing nearly $750 million in the energy market in MISO alone.

Table 1 Net energy market losses[27] across market regions, 2014-2017[28]

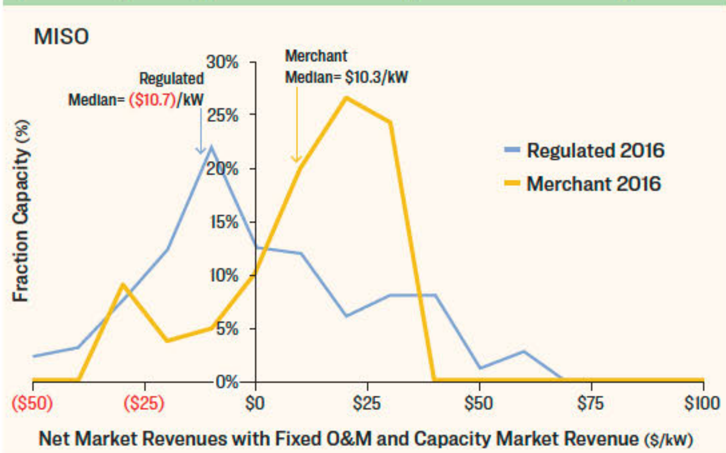
		2014	2015	2016	2017
MISO	Energy Market Losses (M$)	($10.9)	($216.3)	($316.4)	($211.6)
	Capacity w/ Energy Market Losses (MW)	884	18,498	15,445	13,754
	% Capacity Regulated	23%	82%	81%	81%
SPP	Energy Market Losses (M$)	$0.0	($172.5)	($139.0)	($136.0)
	Capacity w/ Energy Market Losses (MW)	–	5,279	4,435	5,141
	% Capacity Regulated	–	99%	99%	100%
ERCOT	Energy Market Losses (M$)	$0.0	($15.4)	($35.8)	($22.2)
	Capacity w/ Energy Market Losses (MW)	–	410	2,628	1,130
	% Capacity Regulated	–	0%	84%	64%
PJM	Energy Market Losses (M$)	$0.0	($42.2)	($134.8)	($87.1)
	Capacity w/ Energy Market Losses (MW)	–	3,332	10,401	7,752
	% Capacity Regulated	–	79%	60%	63%
All Regions	Energy Market Losses (M$)	($10.9)	($446.5)	($626.0)	($456.9)
	Capacity w/ Energy Market Losses (MW)	884	27,519	32,909	27,777
	% Capacity Regulated	23%	84%	77%	79%

However, losses in the energy market alone do not necessarily suggest net revenue loss, accounting for capacity market revenues and other incurred costs. Units in PJM depend on capacity market revenues to cover fixed, and potentially variable, costs. Accounting for the costs of fixed O&M and revenues from capacity markets in MISO[29] and PJM, coal plants with negative net revenue lost over $3.8 billion in 2015-2017 (see Table 2, below). Again, the vast majority of the losses (79-87%) was incurred at regulated power plants. **Overall, we estimate that captive ratepayers of regulated utility coal plants lost $3.5 billion from 2015-2017 relative to the procurement of energy and capacity on the market, due to non-economic dispatch.**

Table 2 Net market losses[30] across market regions, including fixed O&M and capacity market revenues, 2014-2017[31]

		2014	2015	2016	2017
MISO	Net Market Losses (M$)	($86.6)	($952.1)	($692.2)	($473.7)
	Capacity w/ Net Market Losses (MW)	4,500	38,311	32,014	22,265
	% Capacity Regulated	65%	84%	87%	80%
SPP	Net Market Losses (M$)	$0.0	($468.6)	($424.3)	($390.7)
	Capacity w/ Net Market Losses (MW)	–	16,129	16,061	15,256
	% Capacity Regulated	–	84%	88%	84%
ERCOT	Net Market Losses (M$)	$0.0	($75.5)	($154.5)	($110.4)
	Capacity w/ Net Market Losses (MW)	–	4,015	6,938	5,356
	% Capacity Regulated	–	90%	69%	58%
PJM	Net Market Losses (M$)	$0.0	$0.0	($63.3)	($31.2)
	Capacity w/ Net Market Losses (MW)	–	–	7,383	4,785
	% Capacity Regulated	–	–	88%	65%
All Regions	Net Market Losses (M$)	($86.6)	($1,496)	($1,334)	($1,006)
	Capacity w/ Net Market Losses (MW)	4,500	58,455	62,396	47,662
	% Capacity Regulated	77%	87%	87%	79%

Figure 8 Histogram of net market revenue in MISO (includes fixed O&M and capacity market revenue) in 2016, by capacity (% of MW) for regulated and non-regulated coal-burning units.



Some units that incurred marginal net energy market gains had high estimated fixed O&M costs, driving a net annual gain into an overall loss. In MISO, this pattern is particularly pronounced. In 2015, 18.5 GW of coal incurred negative net energy margins (see Table 1, above). Accounting for fixed O&M costs[32] and capacity revenues,[33] some 38 GW of coal capacity incurred costs greater than earned market revenues (Table 2). Again, the vast majority (87%) of the coal-burning units failing to cover costs through market revenues were regulated.

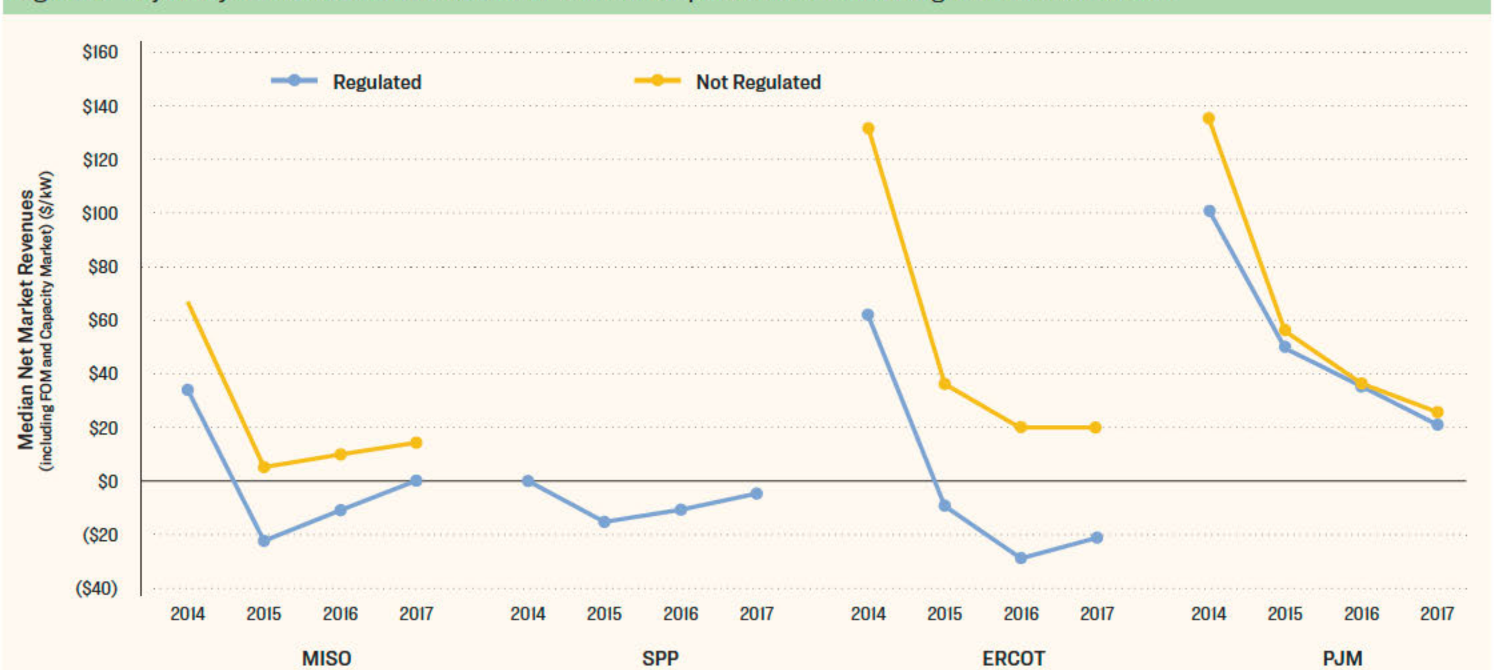
In PJM, prevailing capacity prices have generally been above the estimated fixed O&M cost of coal, and thus the pattern is reversed: some plants that are non-economic on a net energy market basis alone become economic (*i.e.*, receive revenues in excess of their costs) after they receive capacity revenues, despite fixed O&M costs. While we estimate that 10.4 GW of coal in PJM incurred net energy market losses in 2016, that number shrinks to 7.4 GW when we account for fixed O&M costs and capacity market revenues. Even in PJM, the units which incurred market losses were largely rate based (88%).

In every region, there is a separation between the net market revenues received by regulated and non-regulated coal plants. Figure 8, below, shows the separation between the net market revenues of coal-burning units in MISO in 2016 that are regulated and those that are not, weighted by capacity. The median merchant (*i.e.*, not regulated) had net market revenues of $10.3/kW, while the median regulated unit had losses of -$10.7/kW.

Over time, each of the market regions maintains a substantial separation between the median net market revenue for regulated and non-regulated coal units (Figure 7). It is particularly notable that in MISO, SPP, and ERCOT, from 2015-2017 the median coal-burning unit lost net market revenue.

Overall, it is clear that regulated coal units have a substantially different pattern of dispatch in market regions compared to merchant coal units. Namely, over-commitment and/or out-of-merit operation, and the subsequent loss of net market revenue, is almost exclusively constrained to coal units owned by regulated utilities. In contrast, merchant coal-burning plants reduce dispatch and commitment in response to low energy prices, thereby preserving net positive market revenue.

Figure 9 Trajectory of the net market revenue for the median plant in four market regions from 2014-2017



6 SELF-COMMITMENT DRIVES UP COSTS AND DRIVES DOWN MARKET ENERGY PRICES

Plants that dispatch in more hours than is economically optimal can incur substantial losses relative to the market, which are passed on to captive ratepayers if a unit is operated by a regulated utility. While we cannot readily determine if it is the practice of self-scheduling or self-commitment that has resulted in non-economic operation of coal plants, we can examine the impact the practices have had on market energy prices, and ultimately the revenues of other generators who sell on the market.

To determine the impact of self-commitment on generation and market prices, we employed an in-depth unit-specific electric sector model. First, we re-created MISO conditions in 2017; we then tested to see if different dispatch decisions were possible, and how prices, emissions, and costs would have changed if MISO had required economic dispatch from all coal-fired generators, regardless of regulatory status.

Sierra Club retained Synapse Energy Economics to use EnCompass, a unit-specific chronological dispatch model with transmission and operational constraints on coal units, to compare modeled baseline conditions in MISO in 2017 against modeled optimal dispatch in that same year. The methodology employed is described in more detail in **Appendix C.**

The analysis, run using the EnCompass model, was designed to observe the differences between a case calibrated to 2017 actual dispatch and prices (called the "Base Case" here), and a case in which units are operated optimally (the "Economic Dispatch Case"). The primary difference between these cases was that a "must-run" constraint imposed on most coal units in the Base Case was released in the Economic Dispatch Case. The "must-run" constraint is described in more detail below.

- ***Base Case**:* The Base Case was designed to replicate, as nearly as possible, actual operations and costs in 2017 in MISO. The baseline model[34] was calibrated with coal unit-specific production costs from 2017.[35] The variable O&M costs of individual coal units were adjusted such that monthly coal generation on a unit-by-unit basis and energy market prices on a zonal basis replicated, as nearly as possible, actual 2017 generation and prices. We retained operational constraints, including "must run" parameters as assessed by a markets intelligence group, Horizons Energy.
- ***Economic Dispatch Case:*** The Economic Dispatch Case was designed to test how MISO would be dispatched if all units were dispatched as if called upon by the market with a 72-hour look-ahead period. This run released the must-run constraint, but maintained all other parameters of the Base Case. The Economic Dispatch Case retained the composition of the fleet as it existed in 2017; we made no incremental retirements or additions.

Our model runs were designed to test if MISO's coal units, as they exist today, could be dispatched effectively and economically by a market signal and modest look-ahead period without self-committing,[36] and without imposing operational problems or incurring an undue number of startups and shutdowns. To ensure that we were capturing the operational constraints of coal plants, we employed a modeling construct that observed chronological dispatch (*i.e.*, sequential time matters), and which was bound by individual unit ramp rates, minimum runtime constraints (*i.e.*, the minimum number of hours online or offline), and startup costs. In other words, the Economic Dispatch Case would reflect the inflexibility of coal plants, rather than assuming perfectly dispatchable resources, consistent with the limitations system operators face when managing a generation fleet including coal.

- ***Production and fixed costs**:* Data on individual coal unit production and fixed costs were extracted from the S&P Global database, which in turn relies on reporting to EIA's Form 923 for fuel costs and average heat rates, and FERC Form 1 for variable and fixed O&M costs. S&P Global uses a model to gap fill non-reporting entities. Synapse adjusted variable O&M costs of individual coal units seeking to match approximate 2017 generation and regional market prices on a monthly basis. See **Appendix C** for details of the calibration.
- ***Must-run constraints:*** The "must-run" constraint requires that a plant at least operate at minimum load37 if not out on maintenance, effectively requiring the unit to be self-committed at all times. The Horizons Energy database (underlying the EnCompass model) assesses which units act, from a modeling perspective, as if they have a must-run constraint, and imposes such a constraint on those units for the purposes of modeling. This "must-run" constraint does not correspond to MISO-designated requirements to operate for reliability purposes, called a System Support Resource ("SSR"), but rather represents a modeling constraint designed to replicate historic behavior in the Base Case. No units were identified with a MISO-designated SSR designation, and thus every coal unit was released from this modeling constraint in the Economic Dispatch Case.

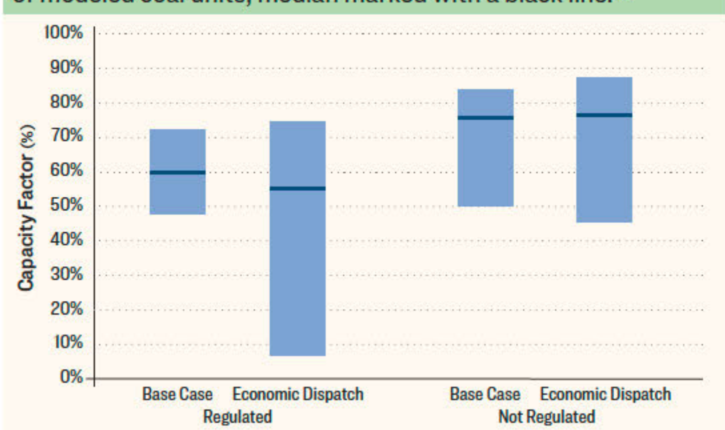
- ***Historic outages:*** Matching historic operations of a large fleet is complicated and is made more difficult by unpredictable forced outage schedules. In particular, without plant records, which are typically confidential, it is nearly impossible to distinguish forced outages, scheduled outages, and economic outages. We erred on the conservative side by assuming that any outage in 2017 lasting a day or longer was equivalent to a forced outage — in other words, it would occur in both the calibrated run (as it did in 2017) and in the economic model run. This effectively means that units which observed economic dispatch and thus, de-committed for a long period of time would see no adjustment from the baseline run to the Economic Dispatch Case; similarly, units which had extended maintenance outages in 2017 would also not see an adjustment between the two runs.

Our modeling demonstrates that the economic dispatch of MISO's coal units in 2017 was feasible, and would have resulted in less coal generation, lower system costs, and higher market prices. Under economic dispatch, coal generation in 2017 fell by about 10%, from about 324 TWh in the Base Case scenario to 293 TWh in the Economic Dispatch Case, a reduction of 30.8 TWh. **The reduction in coal generation when MISO is economically dispatched is almost entirely (93%) attributable to coal units owned by regulated utilities.[38]**

Because this is a historical analysis looking only at re-dispatch of existing units, the generation gap is largely taken up by existing gas-burning units that were already operational in 2017. While not tested here, we expect that on a going-forward, a larger share of the energy gap would be filled by new build renewable energy due to higher market prices.

As in the observed historic behavior, regulated coal units decline in their modeled capacity factor from the Base Case to the Economic Dispatch Case, while merchant units do not (see Figure 10, below).

Figure 10 Capacity factor of regulated and not regulated coal units in MISO in calibrated 2017 model (Base Case) and the Economic Dispatch Case. Bars represent 25th-75th percentile of modeled coal units; median marked with a black line.[39]



Rather than a gradational change, the model predicts that less non-economic units would effectively ramp down to a peaker capacity factor (*i.e.*, <10%) or off; in contrast, relatively economic units do not change dispatch substantially. In reality, we might expect that marginally economic units reduce their dispatch modestly, while uneconomic units are reduced to minimal, peaking capacity factors, or retired altogether if their fixed costs routinely exceed net market revenues.[40]

Economic dispatch increases market prices and revenues paid to all generators, including renewable energy.

When non-economic coal plants shift from self-commitment mode to economic dispatch, it results in an increase in the wholesale market price of energy.[41] Specifically, the supply curve is made somewhat steeper including the minimum operations segments of coal plants that were previously excluded from the bidding process. The dynamic underlying this increase in market prices due to market-based dispatch is discussed in more depth in **Appendix B.**

We assess that across all nine modeled MISO regions, the median hourly market price increases by $7.7/MWh, or around a 30% increase. According to the model results, market prices increase by 30% relatively consistently across both low and high cost hours if coal generators are modeled as operating under economic dispatch.

All units that participate in the energy market, including renewable energy generators, would be privy to higher market prices, and hence greater market revenues. These findings suggest that the practical effect of non-economic self-commitment by regulated coal units is that captive ratepayers pay more for their generation, and thereby subsidize ratepayers of utilities that buy energy from the market. The operation of non-economic coal plants also deprives independent power producers, including renewable energy producers, of critical market revenues — in this case, to the tune of a nearly a quarter of potential revenues. Our modeling suggests, for example, that a 100 MW wind farm could have been deprived of about $2 million[42] in 2017 due to the subsidization of market prices by non-economic coal.

Economic dispatch decreases total system costs.

Despite the increase in the marginal market price of energy, economic dispatch drives down total production costs. Total system costs decrease because non-economic units are no longer forced online, and they are replaced by more efficient and lower marginal cost resources. In reality, the benefit of this production cost decrease would be allocated to customers of regulated utilities who today are subsidizing the operations of out-of-merit coal via state ratemaking processes. **Our modeling indicates that the total production cost of coal-burning generators in MISO would have dropped, from an estimated $10.1 billion to $8.8 billion in 2017, or a savings of $1.3 billion in that year alone.[43] The increase in output of non-coal generators reduces the total savings to $682 million.**

Table 3. Core results from dispatch modeling for MISO, 2017

	Base Case	Economic Dispatch	Difference
Coal generation (GWh)	324,137	293,307	(30,830)
Median market price ($/MWh)	$21.80	$28.28	$7.68
Coal production cost[44] (million $)	$10,069	$8,782	($1,287)
System production cost[45] (million $)	$12,112	$11,430	($682)

These findings confirm that economic dispatch of coal units is both likely occurring, and can be remedied through improved dispatch practice. While our modeling effort does not purport to do a detailed examination of the reliability impacts of market-based dispatch, the model obeys basic reliability and operational constraints, and successfully dispatches MISO without self-scheduling coal-burning units.

One of the most substantial findings here is that the non-economic dispatch of coal units in market regions is likely depressing regional wholesale market prices.[45] This practice disadvantages independent power producers, qualified facilities under the federal Public Utility Regulatory Policies Act ("PURPA"), new renewable energy entrants, energy efficiency programs, net metering customers, and the customers of regulated units that are economically dispatching.

- ***Independent power producers:*** Independent power producers, both fossil-burning and renewable, rely on market revenues to support continued operation and new investments. Competitive providers may be losing substantial market revenue due to non-economic dispatch from regulated coal-burning facilities.
- ***Qualified facilities ("QF"):*** In some states, the contractual price provided to small renewable and combined heat and power producers is based on the prevailing market price, or predictions of market prices. In cases where those predictions are pegged to current prices, QF providers may be substantially undercompensated.
- ***New renewable energy entrants:*** Renewable energy projects are often financed on the basis of a power purchase agreement ("PPA"), which may be accepted (or rejected) in comparison to a market price index. To the extent that market prices are lower than reasonable, new PPAs may be rejected, even if they would otherwise be cost effective. Similarly, merchant renewable providers realize higher risks and lower revenues, discouraging new entrants.
- ***Energy efficiency providers:*** Energy efficiency programs are often assessed against, in part, the avoided cost of energy. When the prevailing market price of energy is higher, a wider array of energy efficiency programs can be employed cost-effectively. If market prices are suppressed, fewer efficiency programs may be deployed, and competitive efficiency providers may be undercompensated.
- ***Customers of economically dispatched regulated plants:*** Customers of regulated utilities that own economically-dispatched generation may be disadvantaged if their power plant is unable to collect due revenue, or have cost-effective generation driven offline by low market prices.

7 DISCUSSION

In recent years, central energy market observers and stakeholders have given substantial — and appropriate — focus to capacity market structures, debating if the market constructs overpay fossil generators or provide appropriate compensation to renewable energy, demand-side management, and storage. And while resolving these questions will be crucial to the development of an energy system that meets ratepayer needs — and that also can meet climate and public health goals — we should not make the assumption that energy markets in RTOs are perfectly competitive, let alone that they are reasonably aligned with climate or health goals.

Our research shows that as market energy prices decline, regulated coal-burning generators seek to preserve operations, at a substantial cost to customers and competitive generators. While regulated coal units in centralized market regions do not appear to be gaming the market, as might be signaled through withholding or seeking to drive up market compensation, they do appear to exploit the disconnect between market operations and fuel recovery before regulators. That gap in oversight — reviewed neither by market monitors nor by most state regulatory commissions—allows regulated coal plants to operate more than would be reasonable under market conditions. And because such behavior is not typically subject to oversight, it is a low risk to utilities but a high economic cost to customers (and on emissions).

Many plants owned by regulated, vertically integrated utilities operate far more often than is warranted by market prices.

This behavior is pronounced when market prices fall, driven either by low prices for pipeline gas or increasing penetrations of renewable energy. The non-economic dispatch of regulated coal plants stands in stark contrast to the generally economic, or at least risk averse dispatch of merchant coal-burning generators. We conclude that such non-economic dispatch (*i.e.*, operating out of merit order) is not fundamentally an operational constraint by coal plants, but rather a difference between operational decisions made by regulated utilities and merchant coal plants.

This systematic non-economic dispatch, whether through self-commitment or extended dispatch out of merit order (*i.e.* without response to market signals) has cost ratepayers of regulated coal units over $3.5 billion from 2015-2017. In other words, we estimate that regulated utility ratepayers, primarily in MISO, but also SPP, PJM, and ERCOT, could have saved more than $3.5 billion in those three years alone by purchasing market-based energy rather than dispatching existing coal-burning units out of merit.

The *pro forma* pass-through of fuel costs allows regulated owners to operate coal units out of merit, or with little respect to market revenue.

While merchant coal-burning power plants must recover all of their costs through energy and capacity markets, coal plants associated with captive ratepayers are able to pass through costs to ratepayers. In many states, the costs of coal are passed through via “fuel adjustment” proceedings, which are, in general, rapid, *pro forma* proceedings in which utilities report the incurred cost of fuel, and request adjustments to rates. These proceedings are often uncontested, and considered relatively low impact, despite the magnitude of costs that are considered during these proceedings. In some states, utilities have expressed an intent that fuel costs only be handled through adjustment proceedings, while other costs are handled through rate cases, or even other *pro forma* adjustment proceedings, such as purchased power adjustment proceedings. The decoupling of these proceedings, and their abbreviated nature, make it difficult for regulators or stakeholders to assess if units have dispatched economically with respect to market prices, and the magnitude of loss.

Regulated coal plant owners have traditionally had relatively little transparency to state utility commissions or customers on self-commitment and dispatch practices.

The operations of generation units in a market region, including commitment and dispatch practice, are complex issues that have traditionally had relatively little transparency before state utility commissions. Specifically, commissions often simply assume that if a market exists, then operators within that market will seek to dispatch economically within that market. Utilities are not generally required to disclose bidding behavior, self-scheduling, or self-commitment behavior, or to reconcile their costs with market revenues. In fact, as of the publication of this paper only two commissions, the Minnesota Public Utilities Commission and the Missouri Public Service Commission, had opened investigations to determine if units owned by regulated utilities were operating economically.[46]

Regulated coal plant owners may see an incentive in operating out of merit.

While utilities are charged with providing reliable, least-cost service to customers, utilities continue to have an incentive to support the operation of existing generation units. In particular, generation units that still have unrecovered plant balance pose a risk to regulated utilities,[47] and showing that those units still operate at high capacity factors — even if those high capacity factors are not merited — is often seen as an implicit demonstration that a generator continues to provide value. Conversely, a unit operated at a low capacity factor may attract unwelcome attention from regulators concerned about continued spending at a clearly non-economic plant. A company that is seeking, at the forefront, to protect shareholder value, and which perceives a lack of oversight in the matter, might see an incentive in operating existing coal units out of merit — even if the practice results in ratepayer losses.

Economic dispatch and economic commitment reduces total production costs, increases market prices, and reduces electric sector emissions.

When coal plants respond to market signals for dispatch and commitment, it reduces total production costs, because power is provided by less expensive generation during more hours. At the same time, market prices increase because those self-scheduled or self-committed high-cost coal units were compelled to operate—effectively pushing them to the bottom of the supply curve. By taking those units out of the bottom of the supply curve, we shift the supply curve to the left, and up, increasing the clearing price of energy. That increased price of energy benefits every generator that was acting competitively. And by decreasing the generation of non-cost effective coal-burning generation, we reduce emissions substantially.

Our research indicated that market prices may have been suppressed to 30% below expected priced due to excessive self-commitment in MISO in 2017.

By paying for excess energy out of merit, ratepayers of regulated coal generators are subsidizing the market price of energy for other consumers within market regions.

The reduced market prices resulting from systemic non-economic dispatch mean that the ratepayers of regulated coal units which operate out-of-merit are effectively paying to reduce market prices for other consumers in the market region. This cross-subsidization means that utilities in market regions that do not own generation and that exclusively purchase market-based energy were provided lower prices at the expense of vertically integrated coal-owning utilities.

Regulated coal operators, through non-competitive operation, may have suppressed clean energy uptake.

New renewable energy projects in market-based regions rely either directly on market prices or on PPAs, which in turn are accepted or rejected on the basis of avoided market energy prices. When market energy prices are suppressed, renewable energy projects realize lower revenues (or lower PPA prices), which restricts the number of projects that may come online. In addition, self-scheduled coal units may generate too much energy during off-peak hours, driving up the curtailment of renewable energy projects. On a going forward basis, we may see lower market energy prices with increasing penetrations of near-zero marginal cost renewable energy, but those market prices will be a result of competitive behavior, rather than market price suppression.

8 RECOMMENDATIONS

How we can remedy the non-economic dispatch of existing coal-burning facilities?

Regulated utilities have argued that the dispatch of existing coal units is premised entirely on operational constraints, and that the lack of a multi-day market inhibits any form of reasonable market-based commitment. Yet co-located merchant generators have successfully avoided taking excessive losses in the market, or have cut their losses through retirement. Even in the absence of a multi-day market, it is clear that there are actions that could be taken by regulated utilities today to more closely hew to market signals when market prices are low.

Commissions and consumer advocates should examine the self-commitment and self-scheduling practices of regulated utility coal-burning power plants in market regions. Such examinations should examine the assessed production cost of existing coal, the bids offered by the utility into the market, how often units are self-committed or self-scheduled, the net losses incurred from these practices, and the process — if any — used by the utility to assess market prices and minimize commitment during low market priced periods.

Commissions should consider alternative incentives to ensure regulated coal plant operators align operations with market prices. Such incentives could include allowing utilities to recover the market price of energy from customers (plus or minus a deadband if required), rather than the production cost of coal generators. Under this kind of structure, a regulated coal plant owner would be incentivized to only run below market costs in order to increase recovery and avoid a penalty. On a near-term basis, Commissions may consider disallowing the recovery of excessive fuel costs if a utility cannot demonstrate that it has dispatched competitively.

Utilities, in the absence of a rigorous multi-day market, should develop a consistent and transparent set of practices for avoiding operations and commitment during periods of persistent low market prices. Such practices include rigorously assessing near-term market price forecasts to inform commitment decisions, and setting internal operating standards that define when a unit should be committed out of market or follow market signals. Rather than simply seeking to avoid startup/shutdown, these standards should rigorously assess the costs associated with full unit cycling, and clearly seek to minimize both short and long-term costs.

Market monitors should rigorously examine the behavior and bids of slow-ramping, coal-burning units to ensure that market costs are not being inappropriately depressed through the non-economic actions. In addition, market monitors should ensure that excessive commitment from coal-burning generators does not displace opportunities for renewable energy, and does force excessive curtailment of renewable generators during low-demand hours.

ISOs and RTOs should consider more advanced forward markets that send a clear commitment-relevant market signal to better inform utilities' decision making, and raise the barrier to self-commitment.

Today, utility regulators rely on market oversight to ensure competitive dispatch by their regulated utilities, while ISOs and RTOs have generally relied on utility regulators to ensure that regulated generators are providing competitive bid information, and have generally assumed that utilities are not incentivized to act non-competitively. The decoupled responsibility of utility regulators and RTOs has had the consequence of allowing non-economic dispatch by regulated utilities to go relatively unchecked, at the expense of captive ratepayers and competitive independent generators. The behavior of merchant coal-fired generators suggests that economic dispatch is achievable. Improved market behavior by regulated coal generators will not only have benefits to the market; it will also have significant climate benefits, and reveal if certain generators effectively serve customer interests in a paradigm of falling market costs and increasing penetrations of clean energy.

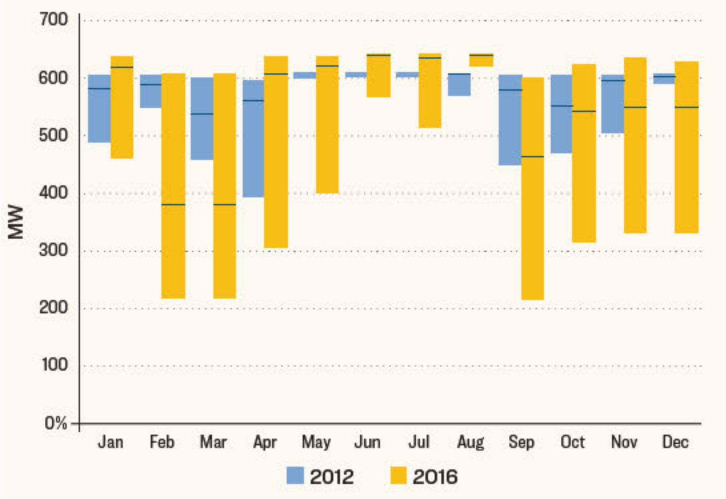
APPENDIX A: CYCLING IN COAL-BURNING POWER PLANTS

Most coal-burning power plants in operation today were built to provide what has been characterized as "baseload" power — *i.e.* continuous power at all hours of the day. Up until the mid-2000s, that was a fair characterization. Indeed, the variable cost of operation at coal plants was often low enough to warrant very high capacity factors. As a consequence, coal plant operators, and then market designers and stakeholders, generally assumed that coal units would operate cost effectively under most conditions.

However, as gas prices and, as a corollary, energy market prices dropped over the last decade, coal-burning plant operators increasingly saw a need for cycling in order to avoid operations during low-cost market prices, and to capture higher cost hours.

By way of illustration, Figure 11 (below) shows the output of Nebraska Public Power District ("NPPD's") Gerald Gentleman Station in 2012 — just prior to the onset of low market prices — as well as in 2016 — one of the lowest market price years experienced to date. The height of the bars indicates the range from the 25th to the 75th percentile, with the median marked between. Taller bars indicate that a unit cycled more during that month, in this case between a minimum operational level of 220 MW and a maximum gross output of about 630 MW. [48]

Figure 11 Output of Gerald Gentleman Station (Nebraska) by month, 2nd and 3rd quartile, 2012 & 2016



Cycling is a function of prevailing market prices. Gerald Gentleman ramped substantially during the shoulder seasons (spring and fall) of 2012, but it had a nearly continuous output of 600 MW during the summer. In 2016, this changed: Gerald Gentleman had to contend with low market prices not just in the shoulder seasons, but also through the winter and early summer. In 2016, the unit ramped on nearly a daily basis, seeking to avoid operation during lower-cost hours.

Many utilities seek to avoid operating coal-burning units during relatively low-cost hours by ramping, and falling market prices have required that ramping occur with greater frequency. However, despite the fact that Gerald Gentleman unit ramped on a daily basis in 2016, it only turned off five times, the longest span of which was less than 3.5 days (81 hours). In total, the unit did not operate for only 8.4 days in 2016.

APPENDIX B: WHY OUT-OF-MERIT OPERATION DRIVES DOWN MARKET PRICES

In an open energy market, the price in any given hour is set as the marginal cost of energy.[49] This pricing structure is meant to minimize incentives for gaming; it helps ensure that generators bid no more than they require, while also ensuring that they receive the clearing price of energy. When a generator provides an "economic" bid to a central marketplace, it is bidding its cost of operation. If that generator has lower variable costs of operation than other resources, and — along with resources that are lower-cost than it is — will meet demands, it will be dispatched by the central operator. The clearing price of generation is set at the highest marginal cost unit (*i.e.*, unit that provided the highest-cost bid) that was still required to meet demand. The bids from generation units, ordered from least cost to highest cost is referred to as the bid stack, and forms a supply curve (*i.e.*, the cost to provide supply ordered by lowest to highest cost generator).

A unit that bids too high risks not being selected by the market operator, but a unit that bids too low risks taking a loss if market prices aren't sufficient to cover its costs. A unit that bids its cost of operation and is selected by the market operator can be assured — under most circumstances — that it will at least recover its costs of operation and potentially more if it is a very low cost unit at high cost hours.

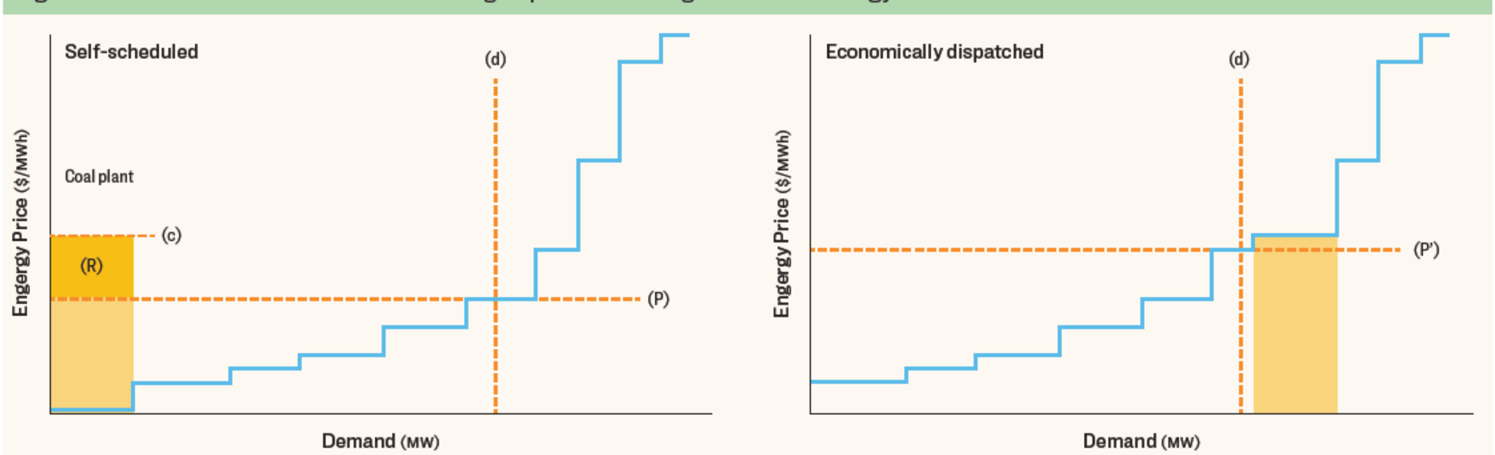
When a generator "self-commits," it guarantees that it will run at its minimum operational level irrespective of its cost or market prices; a "self-scheduling" signal means that the unit will select its own output above its minimum operational level irrespective of cost or market price. When a market operator receives these signals, it pushes the generator into the bottom of the bid stack — *i.e.* at a cost of zero. While a self-committing generator receives market revenues, it has no guarantee that those revenues will be sufficient to cover its costs. And by inserting itself at a cost of zero at the bottom of the bid stack, a self-committing generator pushes the supply curve to the right, lowering the clearing price of energy.

Figure 12 below is a schematic supply curve, demonstrating how self-scheduling impacts the market price of energy. In the left-side schematic, the coal plant (cost *c*) is self-scheduled, and is put into the supply curve at a zero cost. The level of demand (*d*) in this hour determines the marginal resource and the price of energy (*P*). In this case, the price of energy is less than the cost of the coal plant, and thus the coal plant takes a net operating loss, indicated by (*R*). The coal plant is called upon and operates, but can't recoup its costs of that hour through market revenues.

In the right-hand graph, the system is economically dispatched. The coal plant still has the same cost (*c*) but because it bids its cost, it is shifted up in the same supply curve. In this case, the same level of demand does not require the coal plant to be dispatched. However, because the coal plant is no longer at the bottom of the supply curve, the whole curve shifts, and the marginal cost of energy is higher, at P'. All of the generators with costs less than or equal to P' see an increase in revenue.

In the self-scheduled schematic, the losses (*R*) are realized by the plant. But if that plant is owned by a regulated utility, those losses are passed onto ratepayers. As a result, the ratepayers of a regulated, but non-economically dispatched coal plant are charged above-market prices and, by suppressing market energy prices, subsidize the costs of market energy for other consumers. In addition, because

Figure 12 Schematic of how self-scheduling impacts the marginal cost of energy



market prices are suppressed, independent power producers realize a loss of revenue — or don't operate at all if relatively higher cost.

Ratepayers of utilities with self-scheduled generators may not realize that they've incurred the losses shown here. [50] In fact, without an examination of a coal plant's operations relative to market prices, it can be very difficult to assess these losses. Regulated utilities typically pass their costs of generation through to ratepayers as a bulk cost and the revenues from market operations as an offset to those costs. But since most regulated utilities own more than one generator, it may not be obvious to a casual observer that market revenues haven't covered the operational costs of a plant.

APPENDIX C: MODELING ECONOMIC DISPATCH IN MISO, 2017

Sierra Club retained Synapse Energy Economics ("Synapse") to conduct unit-specific economic dispatch modeling in MISO, assessing the impact of economic dispatch against conditions and operations in 2017. The following study was conducted by Synapse, and provided to Sierra Club in June, 2019.

Background

Coal retirements across the MISO region, and downward pressure on energy market prices from increasing energy efficiency (lower demand), increased wind quantities, and natural gas ("gas") prices have spurred questions around the economic dispatch of the existing fleet. In its most recent market roadmap the Midcontinent System Operator (MISO) renewed its commitment to enhancing unit commitment and economic dispatch processes.[51] Accordingly, the Sierra Club tasked Synapse with an exploration of whether regulated coal units in the MISO market region are systematically, uneconomically committed and dispatched. Such a widespread commitment/dispatch inefficiency would represent an effective subsidy of coal units through state-level cost recovery of fuel and operational costs which have not, economically speaking, been reasonably incurred.

The Synapse team utilized the EnCompass model to run two scenarios for the MISO region:

- **The Base Case** simulates unit-specific operational conditions at a monthly time-step granularity, to reflect actual 2017 energy production as reported to the U.S. Environmental Protection Agency (EPA, Air Markets Program data). It includes "must run" designations for coal units.[52]
- **The Optimized Dispatch Case** simulates a purer economic commitment and dispatch. It holds all operational parameters from the Base Case constant and eliminates the must run designations, thereby allowing for a different (i.e., more economically optimal) commitment and dispatch result.

Synapse performed a detailed calibration of the Base Case by aligning monthly coal unit generation, external energy transfers, and market prices to actual 2017 data. The EnCompass model optimizes unit commitment and dispatch to simulate economic operation at the hourly level. Both scenarios are run for all hours of 2017, and are required to meet energy balance, regulation, and operating reserve constraints, along with zonal transmission constraints broadly across and into/out of MISO.

The following memorandum outlines our analysis, presents the results from both scenarios, and summarizes the impact on MISO's generation mix, total system costs (inclusive of fixed O&M), and production costs (exclusive of fixed O&M).

Base Case

Base Case Calibration Process

Synapse calibrated the Base Case to historical U.S. Energy Information Administration (EIA) generation data prior to running the Optimized Dispatch scenario. Our preliminary calibration included checking coal unit capacity levels, simplifying the external regional topology, and calibrating annual generation and net import flows. More specifically:

- **Capacity Check:** Synapse cross-checked the capacity (MW) and retirement dates of coal units included in the EnCompass National Database against data provided by EIA. Where the capacity discrepancy between databases was greater than 25 MW, we performed an additional unit-specific check using publicly available data.[53] We updated retirement dates for six coal units based on EIA data.
- **Topology:** Synapse developed a simplified topology for all regions abutting MISO to streamline the model setup and expedite model run-times. We represented each area within each abutting region (MRO-Manitoba Hydro, NPCC-Ontario, PJM, SERC-North, SERC-Southeast, and SPP) as a single resource with a single capacity and energy value, and priced imports into MISO to approximate the cost of a marginal gas-fired unit.
- ***Annual Operation:*** Synapse calibrated total annual MISO generation by fuel type and net import flows to historical MISO market data.

Our calibration included a careful iteration of coal plant parameters. The Synapse team effectively aligned monthly modeled coal plant output to actual coal plant output levels in 2017 by incrementally adjusting heat rate, operating cost, and outage parameters at the unit level. Based on guidance from the Sierra Club, this calibration focused on four major areas of alignment:

1. **Individual Unit Output:** Synapse calibrated individual coal unit output to actual 2017 monthly generation, as reported by EPA. We also fixed outages to daily reported outages in 2017 at the unit-level.
2. **Must Run Designations:** Synapse found no evidence of any existing MISO system support resource (SSR) agreements for modeled coal units. We maintained effective must run designations determined by Horizons Energy to replicate actual 2017 operation, as described below.
3. **External Transfers:** Synapse aligned our modeling with actual monthly 2017 transfers between MISO and external regions, based on MISO market reports.

4. **Market Prices:** Synapse calibrated to average monthly on- and off-peak 2017 LMPs, for one pricing node in each MISO zone, as reported by MISO.

Synapse utilized unit-level data provided by Sierra Club from S&P Global to align actual variable and fixed operating costs, delivered fuel costs, and heat rates. We also utilized hourly data from the EPA Clean Air Markets division to mirror exact daily unit outage patterns in the MISO region.

Detailed Calibration Results

Individual Unit Output

The Synapse team began by aligning model unit dispatch to historical monthly generation, as reported by EPA. We prioritized alignment for units larger than 150 MW. Figure 13 shows the average monthly delta at the individual unit level by month and MISO region for all units. Figure 14 shows the same calibration data by percent delta. They demonstrate that we met our goal of calibration within an average monthly delta by region of 50 GWh (75 GWh stretch) and 50 percent (100 percent stretch), with few exceptions.[54] The 2017 EPA monthly historical coal generation, modeled monthly coal generation, and the resulting delta are displayed by region in Table 4 below. While we calibrated within our target, the final iteration of modeling saw Base Case generation higher than reported EIA data by an average of 2.1 TWh each month.

Figure 13. Average Monthly Delta, EIA Historical Generation to Modeled Base Case by MISO region

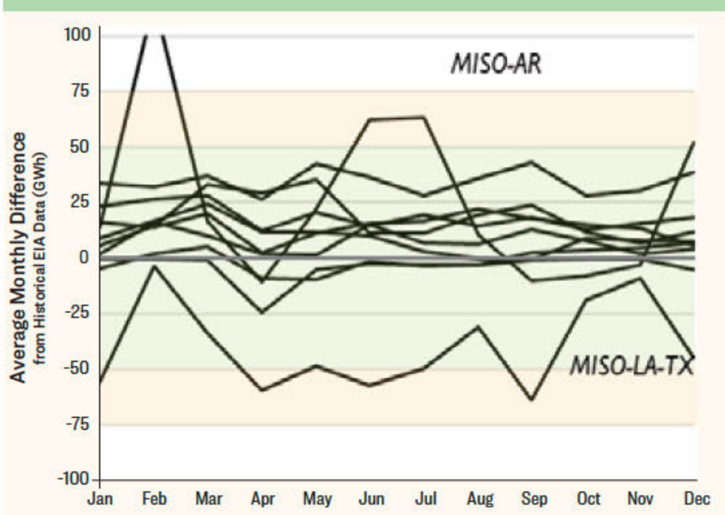
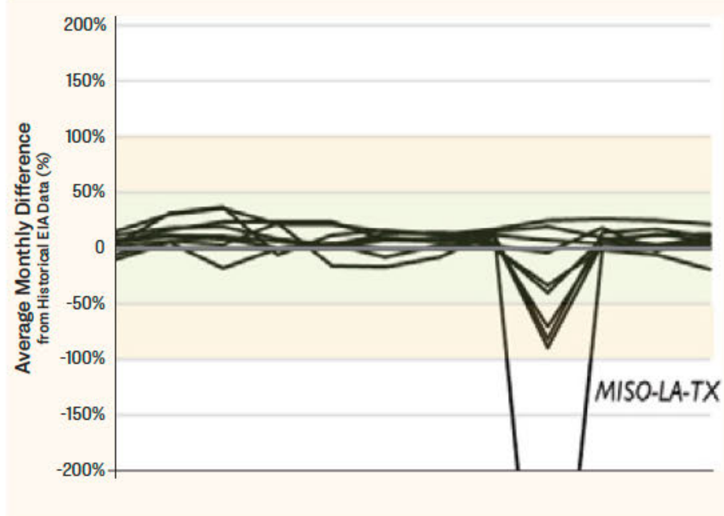


Figure 14. Average Monthly % Delta, EIA Historical Generation to Modeled Base Case by MISO region



Must Run Designations

Synapse determined that there are no active SSR agreements for the slate of modeled coal units in MISO. We rely on the must run designations as defined in the Horizons Energy National Database. These are mostly determined based on Horizons' historical operation calibration to Continuous Emission Monitoring System (CEMS) and EIA data. They are also designed to replicate historical regional stress situations for any period of time. In Encompass, the must run designation requires units to generate at their set minimum capacity level (MW).

External Transfers

Synapse aligned transfers between MISO and external balancing authorities first to historical annual levels and then to monthly levels. On an annual basis, we were able to calibrate net imports to within 15% of historical data without unduly influencing market prices. Monthly net imports reflected in MISO market data and as Base Case modeled outputs are included in Table 5.

Table 5. Monthly Net Imports to the MISO region as reported by MISO and modeled in the EnCompass Base Case

	NET IMPORTS (TWh)		
MONTH	Actual	Modeled	% Diff. Modeled vs. Actual
JAN	3.5	2.9	-16%
FEB	3.4	2.8	-19%
MAR	4.5	3.3	-27%
APR	5.0	4.5	-11%
MAY	5.4	4.3	-21%
JUN	5.1	4.0	-22%
JUL	5.1	4.0	-21%
AUG	5.1	4.6	-9%
SEP	5.1	4.4	-15%
OCT	3.6	4.5	26%
NOV	2.9	2.3	-22%
DEC	2.8	2.5	-13%
TOTAL	51.6	44.0	-15%

Table 4. Coal Generation by Month and MISO region, Historical EIA data, Modeled Base Case, Delta

AREA	GWh	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
MISO-AR	EIA	2,309	1,243	520	964	1,300	1,749	2,065	2,230	1,777	1,127	1,387	1,880
	BASE	2,379	1,822	604	910	1,410	2,059	2,381	2,284	1,727	1,087	1,370	2,140
	DELTA	69	579	84	-53	110	310	316	54	-50	-40	-16	260
MISO-IA	EIA	2,653	1,058	1,159	1,541	2,049	2,568	2,825	2,709	1,971	1,208	1,631	1,899
	BASE	3,183	1,560	1,732	1,952	2,731	3,152	3,285	3,284	2,660	1,655	2,103	2,506
	DELTA	529	501	573	411	683	584	460	575	689	447	471	608
MISO-IL	EIA	3,779	2,886	3,045	2,829	3,123	3,768	3,927	3,580	3,512	3,221	3,751	3,959
	BASE	4,023	3,331	3,728	3,183	3,482	4,053	4,020	3,591	3,498	3,486	3,960	4,160
	DELTA	244	445	682	354	359	285	93	10	-14	264	208	201
MISO-IN-KY	EIA	5,678	4,045	4,147	4,151	4,083	4,803	5,681	5,204	4,153	4,511	4,452	5,048
	BASE	5,462	4,084	4,379	3,770	3,703	4,736	5,482	5,029	4,253	4,610	4,593	5,259
	DELTA	-217	39	232	-381	-379	-67	-198	-176	100	100	141	211
MISO-LA-TX	EIA	1,180	860	525	464	970	1,140	1,121	945	1,096	797	685	954
	BASE	902	842	356	166	728	853	873	790	776	703	640	730
	DELTA	-278	-18	-169	-298	-241	-287	-248	-155	-320	-94	-45	-223
MISO-MI	EIA	3,424	2,906	3,377	3,607	3,659	3,845	4,171	3,354	3,150	3,165	3,324	3,161
	BASE	4,174	3,752	4,259	4,016	4,327	4,328	4,800	3,848	3,731	3,619	3,831	3,788
	DELTA	750	846	881	409	668	483	629	494	581	453	507	628
MISO-MO	EIA	2,704	2,334	2,296	2,335	2,524	2,427	2,840	2,609	2,194	2,562	2,507	2,736
	BASE	2,910	2,515	2,552	2,367	2,672	2,627	3,063	2,899	2,425	2,757	2,682	2,811
	DELTA	207	181	256	32	148	200	223	291	232	195	175	75
MISO-MS	EIA	0	0	1	49	10	4	6	6	8	0	0	10
	BASE	0	0	0	0	0	0	0	0	6	0	0	0
	DELTA	0	0	-1	-49	-10	-4	-6	-6	-2	0	0	-10
MISO-ND-MN	EIA	3,466	2,964	2,629	1,903	2,521	2,755	3,650	3,465	3,084	3,009	3,485	3,482
	BASE	3,541	3,314	2,874	1,971	2,565	3,095	3,828	3,609	3,360	3,204	3,567	3,608
	DELTA	75	350	245	68	44	340	178	144	276	195	82	126
MISO-WI-UM	EIA	3,090	2,680	2,081	1,834	1,963	2,918	3,439	2,936	2,608	2,649	2,877	3,151
	BASE	3,202	3,022	2,848	2,509	2,788	3,171	3,677	3,360	3,147	2,895	3,039	3,398
	DELTA	112	341	767	674	825	253	238	424	539	246	163	247
MISO-ALL	EIA	28,283	20,976	19,780	19,678	22,202	25,978	29,726	27,040	23,552	22,250	24,099	26,280
	BASE	29,775	24,241	23,331	20,844	24,408	28,073	31,410	28,695	25,584	24,017	25,786	28,401
	DELTA	1,492	3,265	3,550	1,166	2,206	2,095	1,684	1,655	2,031	1,767	1,687	2,121

Market Prices

Synapse aligned regional market prices to monthly historical levels. The resulting annual on- and off-peak 2017 prices are shown in Table 6. We calibrated both on- and off-peak prices within 25 percent of actual monthly 2017 LMPs in nearly every area.

Table 6. Historical EIA and Modeled Base Case On- and Off-peak prices by MISO region

	ON-PEAK PRICE (NOM$/MWh)			OFF-PEAK PRICE (NOM$/MWh)		
AREA	EIA	Base	%	EIA	Base	%
MISO-AR	30.53	32.23	6%	23.90	22.61	-5%
MISO-IA	26.10	32.23	23%	19.09	22.61	18%
MISO-IL	31.05	32.23	4%	23.17	22.61	-2%
MISO-IN-KY	34.03	32.23	-5%	25.15	22.61	-10%
MISO-LA-TX	37.27	33.28	-11%	27.31	23.24	-15%
MISO-MI	33.94	32.15	-5%	25.60	22.58	-12%
MISO-MO	28.58	32.23	13%	21.48	22.61	5%
MISO-MS	33.98	33.28	-2%	25.30	23.24	-8%
MISO-ND-MN	27.14	32.23	19%	19.72	22.61	15%
MISO-WI-UM	32.08	32.17	0%	24.28	22.59	-7%
AVERAGE	31.47	32.43	3%	23.50	22.73	-3%

Optimized Dispatch

Optimized Dispatch Set-up

For the Optimized Dispatch Scenario, Synapse used the Base Case as a starting point and removed must run designations from all coal units. The model maintained constraints on energy balance, regulation, operating reserves, and transmission across all time periods. Around 80% of the units representing 95% of the capacity had must run designations (see Table 7). This includes all coal units larger than 200 MW and over half of the units smaller than 200 MW.

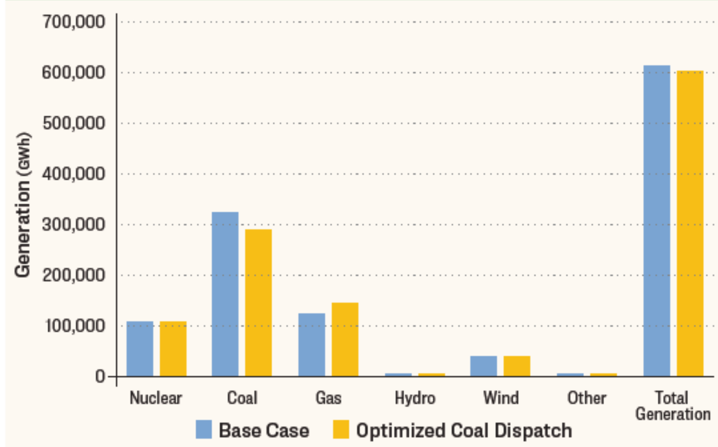
Table 7. MISO Coal Units with Must Run Status

STATUS	# UNITS	CAPACITY (MW)
Must run	154	57,820
% of total	82%	95%
Total	188	60,627

Optimized Dispatch Results

When Synapse removed the coal must run designations, coal generation dropped 10%, largely replaced by existing gas-fired generation.[55] In addition, total production costs within MISO dropped by 5.6% compared to the baseline scenario, driven by decreased generation from relatively high marginal cost coal plants. While total system costs decreased, on-peak wholesale power prices increased by 42%.

Figure 15 Comparison of 2017 Generation by Scenario by Fuel Type



The switch from coal to gas-fired generation was driven primarily by relatively low gas costs, and headroom in existing gas infrastructure. When the must run requirements were relaxed, approximately MISO coal generation dropped by 30.8 TWh and natural gas generation increased by 19.8 TWh.

Under the optimized dispatch scenario, gross production costs in 2017 fell by about 5.6% relative to base costs, a decrease of $683 million, as shown in Table 8. Production costs are comprised of fuel costs, non-fuel variable costs, commitment, and environmental program costs, and do not include fixed operating and maintenance costs. System-wide production costs fall in the optimized dispatch scenario because coal units are no longer forced to generate when the cost of operating a gas unit is more competitive.

Table 8. Production Cost by Scenario and Region

	PRODUCTION COST (MILLION NOM$)	
AREA	Base	Economic
MISO-AR	1,014	1,105
MISO-IA	399	388
MISO-IL	1,176	1,221
MISO-IN-KY	1,824	1,564
MISO-LA-TX	1,904	1,918
MISO-MI	1,909	1,686
MISO-MO	1,023	784
MISO-MS	318	347
MISO-ND-MN	1,119	1,165
MISO-WI-UM	1,428	1,252
TOTAL	12,112	11,430

Gross production cost savings do not include possible increases in O&M costs that could arise through increased cycling of the coal plants. Of the total of roughly 60 GW of coal plant in MISO, 12.1 GW of this amount experienced increased starts per year exceeding one per month. It is possible that these plants, generally smaller-sized units, would incur increased maintenance costs associated with increased cycling. The magnitude of those costs is uncertain; we have no specific data to estimate what the increase might be.[56]

Table 9 provides a high-level summary of scenario energy price deltas. In the Economic Dispatch Scenario, on-peak energy market prices (marginal energy costs) are 42% higher than the Base Case on average. Although energy prices, which represent marginal market prices, are higher in the Economic Dispatch Scenario, total system production costs (Table 8) are lower than Base Case costs. Must run designations commit coal units that would otherwise not run. EnCompass uses a supply stack to determine the price at which there is enough energy to meet demand (the marginal price point). The committed coal units provide energy to meet demand that would otherwise be met further along the supply stack, at a higher price. Thus, when must run designations are removed, the market clears at a higher marginal price.

Table 9. On- and Off-Peak Prices by Scenario and Region

	ON-PEAK PRICE (NOM$/MWh)		OFF-PEAK PRICE (NOM$/MWh)	
AREA	Base	Economic	Base	Economic
MISO-AR	32.23	46.03	22.61	28.05
MISO-IA	32.23	46.02	22.61	28.05
MISO-IL	32.23	46.02	22.61	28.05
MISO-IN-KY	32.23	46.03	22.61	28.05
MISO-LA-TX	33.28	46.63	23.24	28.37
MISO-MI	32.15	46.32	22.58	28.13
MISO-MO	32.23	46.03	22.61	28.05
MISO-MS	33.28	46.63	23.24	28.37
MISO-ND-MN	32.23	46.03	22.61	28.05
MISO-WI-UM	32.17	46.03	22.59	28.13
AVERAGE	32.43	46.18	22.73	28.13

ENDNOTES

1 Data from S&P Global, 2018.

2 Federal Energy Regulatory Commission, 2019. https://www.ferc.gov/industries/electric/indus-act/rto.asp.

3 In this paper, "regulated" will be used as a shorthand for utilities that are vertically integrated — *i.e.*, own both generation and distribution infrastructure—and have captive ratepayers. The term "regulated generators" will be used as shorthand for generation units that are majority-owned by regulated utilities. In this context, the term "regulated" does not specifically mean oversight by a state utility regulatory commission, but includes investor-owned utilities, municipal utilities, and member-owned cooperatives. It is used to draw a contrast with independent power producers, or "merchant" generators. We define if a coal plant is regulated by the status of its majority owner, or first listed operator if evenly divided, according to EIA Form 860 (2017). We identify "regulated" owners as investor-owned, municipally-owned, owned by a cooperative, a state, or other political subdivision. Merchant generators are restricted, in this analysis, to generation units majority-owned by independent power producers.

4 Coal and other steam turbines often have a minimum loading level. A slow-ramping generator, like a coal unit, may elect to self-commit to ensure that it is available to capture anticipated higher priced hours at a future time, rather than being required to go offline during low priced hours.

5 Daniel, J., 2017. *Backdoor Subsidies for Coal in the Southwest Power Pool*. Sierra Club. https://www.sierraclub.org/sites/www.sierraclub.org/files/Backdoor-Coal-Subsidies.pdf.

6 Daniel, J., 2018. *The Coal Bailout Nobody is Talking About*. NASUCA Annual Conference, 2018. Orlando, Florida. Union of Concerned Scientists. https://www.nasuca.org/nwp/wp-content/uploads/2018/01/NASUCA-Coal-bailout-nobody-is-talking-about.pdf.

7 Southwest Power Pool Market Monitor Report, 2017. May 2018. *E.g.*, Page 6 ("Self-commitment of generation continues to be a concern because it does not allow the market software to determine the most economic market solution. Furthermore, it can contribute to market uplifts and low prices. Some of the reasons for self-committing may include contract terms for coal plants, low gas prices that reduce the opportunity for coal units to be economically cleared in the day-ahead market, long startup times, and a risk averse business practice approach."). https://www.spp.org/documents/57928/spp_mmu_asom_2017.pdf.

8 The Power Bureau. 2018/ Analysis of Market Impact for Proposed EmberClear Generation Facility in Pawnee Illinois. http://files.sj-r.com/media/news/Chamber_Report_on_EmberClear.CWLP.pdf

9 MISO Indiana Hub, flat average of hourly day-ahead energy prices. Data from S&P Global.

10 Estimates compiled from data in S&P Global supply curve.

11 Source: EPA Clean Air Markets Data (CAMD) Air Markets Program Data (AMPD), hourly data for 2012 and 2016. Author's calculations.

12 Source: EPA Clean Air Markets Data (CAMD) Air Markets Program Data (AMPD), hourly data for 2012 and 2016. Author's calculations.

13 Refer to In the Matter of an Investigation of Missouri Jurisdictional Generator Self-Commitments into SPP and MISO Day-Ahead Energy Markets, File No. EW-2019-0370 (Aug. 23, 2019).

14 National Renewable Energy Laboratory. April 2012. Power Plant Cycling Costs. https://www.nrel.gov/docs/fy12osti/55433.pdf.

15 There may be circumstances in which a coal unit seeks to primarily capture capacity market revenues (rather than energy and capacity market revenues). However, even in these cases, a coal unit will attempt to avoid market prices below its production cost.

16 We note that in most market regions, generators are provided "uplift" payments when they are committed or dispatched as part of the optimal solution but energy market revenues are not sufficient (on a daily basis) to cover production and commitment costs. For any coal units that are somehow relatively low-cost overall but entail high start costs and long start times, uplift payments may be substantial. We do not expect large differences between uplift payments at merchant and regulated utilities.

17 Virginia Docket PUR-2018-00195, Dominion Rate Adjustment Clause (RAC) for coal ash retrofits at various coal units. Rebuttal testimony of Glenn Kelly, page 18 at 3-5 ("The forecasted capacity factors [for Chesterfield Units 5 & 6], in conjunction with the historical capacity factors, are indicative of units that are providing significant fuel savings and effectively serving customer load"). In contrast, we estimate that Chesterfield 5-6 operated more than expected by increasing capacity factors more than 37% above ideal (more than double the ideal output in 2016), and subsequently lost more than -$22 million in net energy market revenues, or -$19 million when accounting for capacity market revenue and fixed O&M costs.

18 We distinguish here the need for short-term reliability as scheduled by the RTO against a utility's legitimate longer-term need for capacity in market regions where capacity is primarily self-supplied (i.e MISO and SPP). For long-term purposes, a utility might identify a capacity need, but that capacity need almost certainly does not justify ongoing non-economic dispatch, and may be more readily served by lower cost resources.

19 Nelson, W., Liu, S. March 26, 2018. "Half of U.S. Coal Fleet on Shaky Economic Footing: Coal Plant Operating Margins Nationwide." Bloomberg New Energy Finance.

20 *Id*. Page 46

21 *Id*. Page 46

22 "Regulated" generation units, for the purposes of this paper, are units owned by municipal utilities (like Austin and San Antonio's municipal utility districts) and rural electric cooperatives (such as San Miguel). It does not include any state commission-regulated investor-owned utilities.

23 For a slow-ramping coal unit, or any unit with operational constraints, optimal dispatch is effectively impossible. It entails capturing 100% of every hour in which market prices are above production costs, and rejecting every hour in which market prices are below production costs. And while that theoretical optimal level of dispatch is not fully achievable in practice, it is a useful benchmark for the operations of units on a statistical basis — and substantial improvement in the real world towards theoretical optimality can in fact be made. Over a year-long period, we would expect units to fall slightly above or below the optimal dispatch behavior — slightly above if risk tolerant, or slightly below if risk averse or incurring extended maintenance outages.

24 This analysis excludes co-generation facilities, which produce both process steam and power as revenue sources, and may be de-linked from energy market pricing.

25 Because units have operational constraints and may have scheduled or forced outages, we would not expect even the most efficiently dispatched units to necessarily fall along the 1:1 line.

26 "Construction kicks off for Edgewater Unit 5 scrubber." Transmission Hub. April 25, 2014. Accessed August 2019. https://www.transmissionhub.com/articles/2014/04/construction-kicks-off-for-edgewater-unit-5-scrubber.html. The scrubber cost $230 million. Power Magazine, October 2017. Accessed August 2019. https://www.powermag.com/a-breath-of-cleaner-air-on-the-lake-michigan-shore/.

27 "Net Energy Market" loss refers to the differential between total revenues received on the energy market (only) and production costs (*i.e.* fuel and variable O&M).

28 Regions and years with zero values indicate that no plants incurred losses relative to market prices.

29 MISO's capacity market is a voluntary residual market. We assume that the resulting capacity price reflects the opportunity cost of acquiring or selling excess capacity in that year.

30 "Net market" loss refers to the differential between total revenues from both the energy and capacity markets, less production costs and fixed O&M costs. We do not estimate incremental losses due to ongoing capital expenditures.

31 Regions and years with zero values indicate that no plants incurred losses relative to market prices.

32 Estimated by S&P Global from FERC Form 1 filings and modeled.

33 Weighted average capacity price of $11.2/MW-day in most zones.

34 Based on a topology and default unit costs and operational constraints from Horizons Energy database, acquired as part of the model licensure.

35 Derived from S&P Global, 2017

36 While we can capture self-commitment practice (i.e. staying on at minimum loading), neither the calibration run nor the optimal run can capture self-scheduling practices without internal information about decisions made by plant operators.

37 Coal units and other steam-based power plants have a minimum output (in MW), below which the unit is unable to operate effectively. A decision to operate is a "commitment" to generate at least at the minimum load.

38 The remainder of the reduction is attributable to units identified as owned by industrials, a type excluded from this analysis otherwise because industrial users often have other criteria for the use of on-site energy, such as steam generation.

39 Assessment restricted to units which operated in 2017 according to data reported to EIA Form 923.

40 The model characterizes the number of unit starts (i.e., the number of times a unit is started from zero generation) during the year. Operators try to prevent numerous unit starts at coal units to reduce wear and maintenance costs. In both modeled cases, the median number of unit starts remained the same between at approximately five (5) unit starts per year. However, the model predicts that, even with substantial startup costs, less economic units might be subject to more unit starts. In the economic dispatch case, twenty-six units are subjected to more than 15 unit starts per year in the economic dispatch case. In reality, a unit might simply elect not to run rather than be subject to this many starts per year.

41 Note that an increase in wholesale rates does not necessarily translate to an increase in retail rates.

42 Assuming a 30% capacity factor and all-hours increase of $7.7/MWh.

43 This value accounts for the fixed O&M cost of coal generators in the analysis.

44 The cost of production in this table reflects total fuel, variable O&M, and fixed O&M, although only fuel and variable O&M are used to determine the short-term variable cost of production for dispatch purposes. The change in production cost from the base case to the economic dispatch case reflects only change in fuel and variable O&M. Fixed costs remain fixed.

45 It is important to note that depressed wholesale prices do not necessarily imply that retail costs have been suppressed or reduced. In fact, captive ratepayers of utilities with non-economically dispatched coal units likely have paid higher retail rates.

46 Minnesota Public Utilities Commission, Docket Nos. E-999/AA-17-492, E-999/AA-18-373, In the Matter of the Review of Automatic Adjustment Reports for All Electric Utilities; Missouri Public Service Commission, Docket No. EW-2019-0370, In the Matter of an Investigation of Missouri Jurisdictional Generator Self-Commitments into SPP and MISO Day-Ahead Energy Markets.

47 Sierra Club, 2018. Harnessing Financial Tools to Transform the Electric Sector. Available online at www.sc.org/financial

48 Source: EPA Clean Air Markets Data (CAMD) Air Markets Program Data (AMPD), hourly data for 2012 and 2016. Author's calculations.

49 Marginal cost of energy: the cost of the last megawatt to come online, or the first megawatt that would get turned off if that energy was not required.

50 Ratepayers who pay for an out-of-market coal unit (*i.e.*, above market price) also have a slight offset from lower energy market prices for the portion of their energy usage purchased off the market and not attributable to plants owned by their utility.

51 Also, notably, ongoing annual technical conferences at FERC address the inefficiencies associated with RTO-based unit commitment and dispatch operations, and software utilization to aid those processes. The issues are numerous, and highly complex. See, e.g., https://www.ferc.gov/industries/electric/indus-act/market-planning.asp.

52 Must run designations represent minimum run time or operational levels for coal units coded into the database of unit parameters.

53 Units with joint ownership shares outside of MISO were excluded from this process.

54 The two large coal plant in the MISO-AR region, Independence Steam and White Bluff, see consistently higher modeled output than historical generation, on average 40 MWh more per month. The Synapse team was unable to replicate the high output of these units using cost parameters without unduly impacting regional market prices. Similarly, in the MISO-LA-TX region, the Synapse team was unable to incent operation for Big Cajun unit 2:1 without affecting regional price and generation patterns, which caused the divergent percent deltas shown.

55 Imports also increased by nearly 23%. Imports were priced as marginal natural gas units, and thus imply an even greater shift toward natural gas.

56 An increase on the order of $10/kW-year of fixed O&M for 12.1 GW of coal plant would translate to $121 million/year, or roughly 17.7% of the gross production cost savings seen.

Sierra Club National
2101 Webster Street, Suite 1300
Oakland, CA 94612
(415) 977-5500

Sierra Club Legislative
50 F Street, NW, Eighth Floor
Washington, DC 20001
(202) 547-1141

facebook.com/SierraClub
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Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

SIERRA CLUB EXHIBIT 103

Exhibit Accompanying the Opening Testimony of Ed Burgess

Southwest Power Pool, *Self-committing in SPP markets: Overview, impacts, and recommendations*

SPP Southwest Power Pool
MARKET MONITORING UNIT

Self-committing in SPP markets: Overview, impacts, and recommendations

Published December 2019

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1 OVERVIEW AND RECOMMENDATIONS

In this report, we examine self-commitment offer behavior in SPP's Integrated Marketplace, and describe how self-commitment can affect market participants and market outcomes.

Towards that end, we conducted an empirical study analyzing offer behavior over the period of March 2014 to August 2019, and ran two simulation series of a week per month from September 2018 to August 2019 where we re-solved past market cases. The simulations included the following assumptions: (1) all generation is offered in market status, and (2) all generation offered in market status can be started economically by the day-ahead market.

Key takeaways from our analysis include:

- The volume of self-committed megawatts has declined over time, but remains nearly half of the total megawatt volume generated from March 2014 through August 2019.
- Prices and production costs were systematically lower when at least one self-committed unit was marginal.
- In almost all cases, self-committed generators had lower revenues because of negative congestion prices; whereas, market-committed generators typically had a more balanced congestion profile.
- Resources with long lead times and/or high start-up costs tend to be self-committed instead of market-committed.
- Units that are self-committed generally have much higher capacity factors than those that are market-committed. However, these results differ substantially by fuel type.

Key takeaways from the simulations include:

- When the market made unit commitment decisions, and lead times remained unchanged, both market-wide production costs and market clearing prices for energy increased.

- When the market made unit commitment decisions and lead times were modified to allow the day-ahead market to commit the resources with long lead times, market-wide production costs were essentially unchanged and market clearing prices for energy increased.
  - System prices increased by about $2/MWh (seven percent) on average.
  - Congestion prices changed by about –$1/MWh to $1/MWh on average.
- To optimize long-lead time resources' participation in the market, the economic commitment process would need to solve over a longer market window (e.g., over a two-day period rather than just one day).

1.1 RECOMMENDATIONS

- In order to improve price formation and market efficiency, we recommend SPP and stakeholders work to reduce the incidence of self-commitments.
- We recommend modifying SPP's market design by adding one additional day to the market optimization period.[1]

1.2 OUTLINE

The paper is organized as follows. In chapter 2, we cover the mechanics of self-commitment in the SPP market, how this impacts the supply curve, and identify reasons participants may choose to self-commit their generation. Chapter 3 covers the theoretical underpinnings of the market and efficient price formation. Chapter 4 presents empirical observations over the study period comparing market and self-commitment behavior. Chapter 5 covers self-commitment behavior and price formation. Chapter 6 presents two simulation scenarios estimating how market results

[1] SPP has found in its multi-day forecasting study, the accuracy of forecasts (load and wind) remain at acceptable levels for a second day but decline sharply afterwards.

would change if participants market-committed versus self-committed. Chapter 7 highlights our conclusions.

The empirical study period spans from March 2014 through August 2019 and covers all resources and fuel types. However, in our presentation of offer and generation related metrics, we exclude nuclear resources because of the limited number of resources with this fuel type.[2]

Readers of this report may note that the analysis of self-commitment differs from what we have presented in our previous reports. In our annual and quarterly state of the markets reports, we have presented self-commitment information in the form of offers and unit starts. In this report, we focus instead on the megawatts produced from self-committed units.

The re-run (simulations) study period covers the first week of each month from September 2018 through August 2019.[3] We believe that this provides a significant enough sample of re-runs to capture seasonality in the market.

[2] Many of the charts and analysis that follows presents offer behavior by fuel type. As there are a limited number of nuclear resources, any charts that show this as a fuel type could potentially expose specific market offer data. All other resources have a sufficient number of resources to mask any specific offer behavior.

[3] Additional information regarding the sample set can be found in chapter 6.

2 SELF-COMMITMENT MECHANICS

In the broadest terms, and similar to other auction-based electricity markets, the Integrated Marketplace attempts to minimize the cost to serve load[4] subject to transmission and generator constraints. The day-ahead market does this by using two main tools: centralized unit commitment[5] and economic dispatch.[6]

Centralized unit commitment sorts the available generators from least expensive to most expensive and then selects the least expensive units that can achieve the objective without violating the constraints of the optimization.

Economic dispatch then uses the results of the unit commitment process as inputs to its own separate optimization. The results of which produce two key, time-based outputs: the megawatts each generator should produce at the corresponding locational prices.

Centralized unit commitment and economic dispatch processes are designed to work together to make the market more efficient. For instance, FERC stated that "…the unit commitment process an essential part of least-cost operation" when discussing price formation in organized wholesale electricity markets.[7]

The idea behind centralized unit commitment is essentially this: In the same way a team will likely realize better outcomes when the coach selects both the players and plays, the Integrated

[4] The cost to serve load is also referred to as production cost.

[5] The Integrated Marketplace Protocols define Security Constrained Unit Commitment as an algorithm capable of committing Resources to supply Energy and/or Operating Reserve on a co-optimized basis that minimizes commitment costs while enforcing multiple security constraints. Integrated Marketplace Protocols, Section 1 Glossary

[6] The Integrated Marketplace Protocols define Security Constrained Economic Dispatch as an algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve on a co-optimized basis that minimizes overall cost while enforcing multiple security constraints. Integrated Marketplace Protocols, Section 1 Glossary

[7] Price Formation in Organized Wholesale Electricity Markets, Docket No. AD14-14-000

Marketplace will also probably realize better outcomes, for the collective, when it commits units in addition to dispatching them. While the team's record might be the same regardless of who is on the field, it is unlikely that the plays called, points scored, or yards gained would be the same.

Much like players choosing when to play, the SPP market allows participants to self-commit resources rather than have the market choose which units to run. While there may be good reasons for this (see Section 2.2 below), the practice can distort prices and investment signals.

2.1 TYPES OF COMMITMENT STATUS

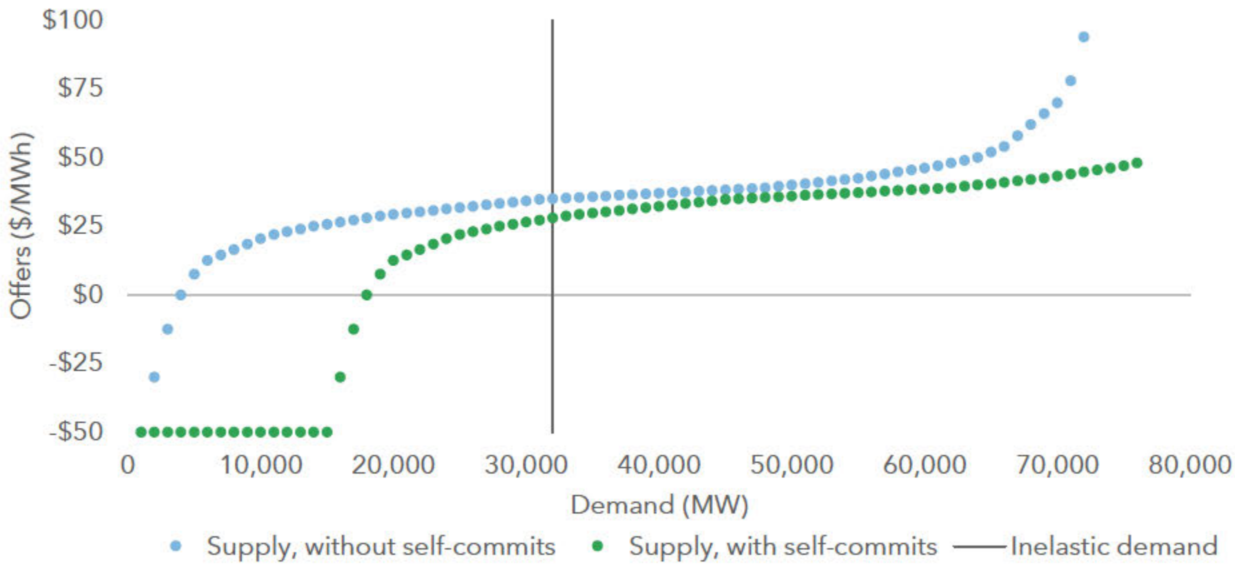
Including self-commitment, the Integrated Marketplace permits five different commitment statuses. The statuses convey information to the centralized unit commitment process. Each status and its accompanying description can be found below:

1. Market – the resource is available for centralized unit commitment through its price sensitive (merit-based) price quantity offers.
2. Self – the market participant is committing the resource through price insensitive offers outside of centralized unit commitment.
3. Reliability – the resource is off-line and is only available for centralized unit commitment if there is an anticipated reliability issue.
4. Outage – the resource is unavailable due to a planned, forced, maintenance, or other approved outage.
5. Not participating – the resource is otherwise available but has elected not to participate in the day-ahead market.

Because the day-ahead market cannot dispatch resources with commitment statuses of outage and not participating, we included market, self, and reliability commitment statuses in our empirical study. However, due to the extremely low megawatt volumes[8] dispatched from reliability-committed units, we present and discuss only market and self statuses in the report.

Mechanically, self-commitment can affect the construction of supply curves by altering the generators selected to serve the demand. Self-commitment shifts the merit order of the supply curve by treating the self-committed generators as price insensitive, which shifts the supply curve to the right.[9] This relationship is shown in Figure 2—1.

Figure 2—1 Rightward shift in market supply curve



The blue supply curve represents supply without self-committed megawatts, whereas the green supply curve represents supply including self-committed megawatts. When participants self-commit resources, the commitment algorithm does not make the decision to commit those units based on their cost. Participants make their own commitment decisions without regard to the optimization of total costs. Said another way, these resources effectively move themselves to the bottom of the cost curve. The result of a rightward shift in supply, all else equal, likely

[8] Over the study period, less than 0.004 percent of dispatched megawatts sourced from units committed in reliability status.

[9] Moreover, the supply curve itself can be reordered as resources whose commitment costs are high can also change the order of dispatch of incremental energy.

reduces the market's marginal clearing price.[10] In addition to shifting the supply curve to the right, the slope of the supply curve also changes when generators self-commit. The change in slope reflects the re-ordering of suppliers in least cost merit order for market dispatch based on the set of resources from the commitment process.[11]

Along with shifting and reordering the supply curve, when participants self-commit resources, their economic minimums essentially create a resource specific dispatch megawatt floor. These floors in turn, create additional constraints to which the economic dispatch optimization must solve around. Self-committed resources also carry the lowest curtailment priority, which means they are generally the last producers instructed to reduce output.[12] Because these self-committed units are deemed "must run", the dispatch engine cannot take them off-line for economic reasons.[13]

2.2 REASONS FOR SELF-COMMITMENT

We have worked with market participants to understand the reasons that participants self-commit generators. Market participants have stated the following reasons for self-commitment:

- Testing – NERC requirement
- Public Utilities Regulatory Policy Act (PURPA)
- Federal service exemptions
- Started by a different market
- Weather
- Long lead times

[10] This is also known as the system marginal price.

[11] Under certain circumstances, this type of reordering could cause a price increase, but this has not been observed. Typically, the reordering has resulted in price declines.

[12] Integrated Marketplace Protocols, Section 4.3.2.2 Day-Ahead RUC Execution

[13] Integrated Marketplace Protocols, Section 4.4.2.5 Out-of-Merit Energy (OOME) Dispatch

- Fuel contracts
- Other contracts
- Long minimum run times
- Commitment bridging
- Desire to reduce thermal damage to the unit due to starts and stops
- High startup costs

Some of these reasons are unavoidable and can require the resource to be offered in self-status. Testing the output of a plant, as periodically required by regulatory agencies, is a frequent justification. A few generators in SPP are classified as qualifying facilities under the Public Utilities Regulatory Policy Act, and the commitment of those resources cannot be separated from other uses, such as cogeneration processes. Additionally, a small group of SPP resources qualifies for Federal service exemptions. Finally, a participant may need to self-commit a resource during very cold weather for reliability reasons.

Some of the reasons, such as high start-up costs, fuel contracts, or commitment bridging are economic in nature and can be handled within the market offer through dollar-based offer parameters. Thermal damage due to start-ups and shut-downs and resulting major maintenance could be included in mitigated offers starting in April 2019.[14] As we show later in the report, we have seen a general decline in self-committed generation over time and it is possible that perceptions of economic justifications have changed over time.

To the extent that a long lead time[15] is reflective of operating or environmental limitations, there may be a software limitation. To the extent that there are limitations to the software, these can be addressed through market design changes.

[14] Revision Request 245.

[15] Based on August 2019 offers, 7 percent of resources (or MWs) had lead times longer than 32 hours and 10 percent had between 24 and 32 hours.

3 MARKET FEEDBACK LOOP

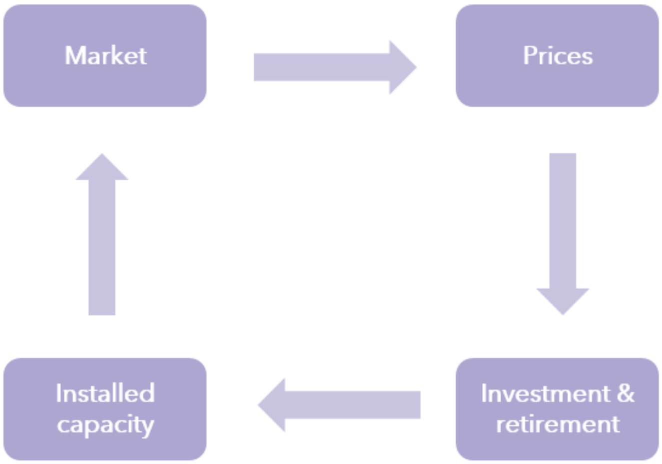
As we showed in the previous section, self-commitment of generation can put downward pressure on the marginal clearing price of energy. In this section, we discuss how the marginal clearing price drives the market feedback loop to bring about equilibrium and efficiency.

A central theory in economics is that competition leads to efficiency.[16] If the market design effectively fosters competition, a competitive equilibrium is possible, and by extension, efficiency may be gained. In electricity markets, a primary source of efficiency gain stems from the minimization of system production cost through centralized clearing. When this occurs, resulting prices are based on marginal costs and the level of production and consumption is optimal – the result is an efficient market at competitive equilibrium.

Market equilibrium generally has two time dimensions: the short-run and the long-run. In the short-run, market participants profit maximize by asking themselves, "What is the best we can do with our current set of resources?" They submit their best answers in the form of market offers. The market provides feedback in the form of commitment, dispatch, and prices. Market participants then use this information to adjust their short-run profit maximizing behavior. Concurrently, participants ask themselves, "What is the best we could do if we had something different?" This question relates to long-run market equilibrium and decision-making to include investment (or retirement) in installed capacity. The search for short-run and long-run equilibriums creates the market feedback loop. In the following sections, we will examine how self-commitment can affect this process and, by extension, market efficiency.

[16] Perfectly competitive markets attain both *productive efficiency*—where output is produced at the least possible cost—and *allocative efficiency*—where output produced is the one that consumers value most.

Figure 3—2 The market feedback loop



3.1 THE MARKET

For competition to flourish, several conditions must exist including having the lack of market power by market participants,[17] the necessary cost information,[18] and non-convex operating costs.[19] Good market design, along with effective regulation and monitoring, helps bring about the first two requirements. The third requirement, however, is unlike the first two. Convexity or lack thereof, is inherent to the characteristics of the resources that participate in the market. Non-convex costs occur when it is cheaper to produce two units than to produce one. Generator start-up and no-load operating costs have this property and are non-convex. As such, when non-convex cost elements exist, designing a competitive market with an efficient pricing mechanism is difficult. However, when suppliers lack market power and have necessary cost information, the improved, if not perfect, level of competition can still bring about efficiency improvements.

[17] A lack of market power implies being a price taker.

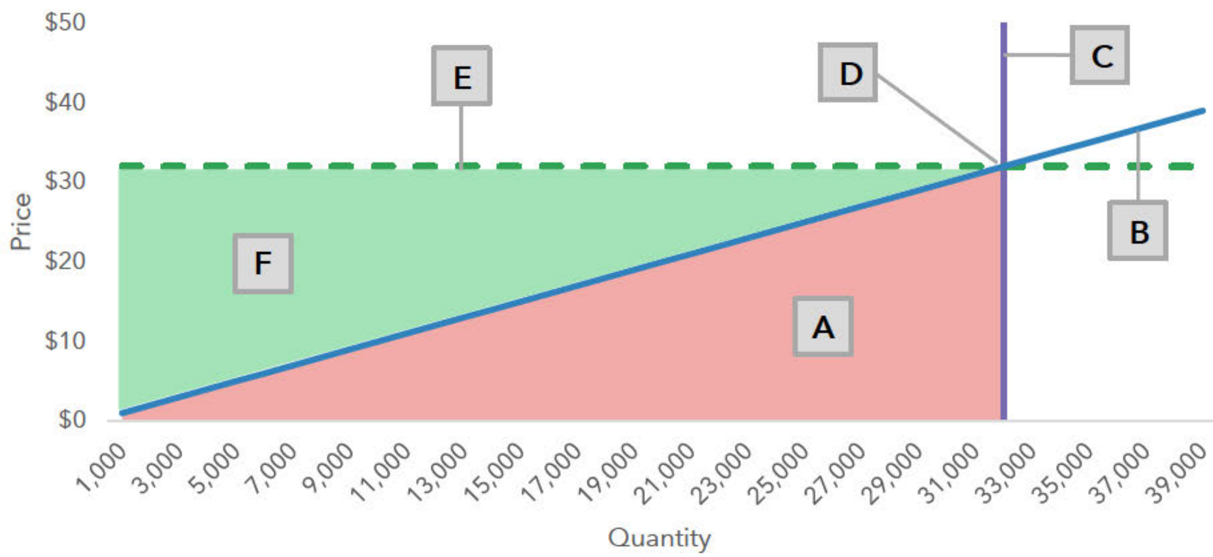
[18] All production costs are known.

[19] The shape of the cost curve is a critical input to the supply function. Classical economics assumes that costs are convex. In practice, some costs are nonconvex.

3.2 LINKING THE MARKET TO PRICES

Economics has concepts that are very precise and have specific meanings. For example, accountants and economists both use the term profit. However, the idea each intends to convey can differ materially.[20] For this reason, we provide the following simplified figure[21] and associated terms to help convey the appropriate intention.

Figure 3—3 Market supply and demand



A. The red shaded region is the production cost,[22] more specifically the energy portion of total production cost.[23] This region is also referred to as the area under the supply (or marginal cost) curve, which gives *total* variable cost, or *total* marginal cost.

B. The supply curve is the blue line. In electricity markets, the supply curve is created by summing the offers of market participants. These offers are submitted in price/quantity

[20] For instance, the IRS expects income tax even when economic profit is zero.

[21] In order to facilitate illustration we use a linearized approximation (of a stepwise line) under a continuous function assumption.

[22] Corresponding to "mitigated offers" in SPP tariff terms.

[23] Production cost is generally presented as the sum of energy, start-up, no-load, and ancillary service costs.

pairs each indicating minimum price levels the supplier is willing to offer for the corresponding quantity. The price the supplier wants to be paid is plotted on the y-axis, and the quantity the supplier is willing to produce for that price is plotted on the x-axis.

C. The demand curve is the purple vertical line.[24] The demand curve shows price/quantity pairs each indicating maximum price levels the consumer is willing to demand for the corresponding quantity. Electricity is mostly a non-storable product and must be supplied instantly upon demand. Further, when there is no competition at the retail end, price elasticity is very low. As such, we represent demand as a vertical line.

D. The market-clearing price is the point where the supply meets the demand. When this occurs, all buyer orders have been filled and the market is said to have cleared. In an organized wholesale electricity market setting, the market clearing price is also called the spot price.

E. The dark green dotted line reflects the price each supplier is paid and is equivalent to the market-clearing price. This equilibrium price multiplied by the total quantity produced is the revenue received by all suppliers.

F. The light green shaded region is the producer surplus. Generally, when economists refer to profit, they are referring to the producer surplus. Short-run profits for individual producers can be calculated by subtracting variable costs from revenue where revenue equals market clearing price multiplied by the quantity produced.[25]

[24] This represents perfectly inelastic demand. Under that assumption, demand is not responsive to price. In practice, the line may not be vertical, having a certain degree of downward slope depending on the degree of price responsiveness in the market, particularly in the day-ahead market.

[25] In electricity markets, start-up and no load costs, in addition to incremental energy costs, need to be included in the short-run profit calculation.

3.3 PRODUCTION COST MINIMIZED, NOT PRICE

The objective function of the market clearing software, stated generally, is to minimize production cost, not the marginal clearing price.[26] Broadly, production cost is the sum of energy,[27] ancillary services,[28] start-up,[29] and no-load[30] costs. Efficiency occurs by serving the same level of demand, while at the same time minimizing the sum of these costs. The clearing price is an output of the optimization and a component of the total production cost. Because the clearing price only relates to a component of the production cost (i.e., the incremental energy component), there is no guarantee that an increase in energy prices will translate to an increase in total production cost.

3.4 PRICE TO INVESTMENT SIGNALS

In the long run producers are incented to invest in projects that minimize their costs.[31] When current prices reflect the true marginal cost of the current set of producers at the margin, participants can better determine the cost structure of the market. When participants have better information, they will likely better optimize their existing generation portfolio. However, in the long run some market participants may not be able to use their existing fleet to achieve their desired level of profitability or recover their cost of capital. When participants find themselves in this situation, they consider entry and exit decisions. Typically, this means

[26] In this cost minimization problem, prices are discovered by identifying the marginal cost of serving the next increment of load during a specific interval and location.

[27] Energy is a power flow for a time period.

[28] Ancillary services are needed to maintain reliability of the system, often by forgoing the opportunity to sell energy.

[29] Start-up is the cost associated with preparing a generator to produce (and stop producing) energy or ancillary services.

[30] No-load is the theoretical cost of running a generator while producing no output.

[31] In a competitive market, the market price is given to individual suppliers and all they can do is to adjust their production amount that minimizes cost.

generators whose long run costs exceed projected revenues retire.[32] Then suppliers either permanently exit the market, focus on reducing maintenance costs, place the unit in reserve shutdown (i.e., mothball),[33] or invest in new lower cost generators.

3.5 INVESTMENT SIGNALS TO INSTALLED CAPACITY

Spot prices are an input to forward price projections and bilateral contract prices. Therefore, a spot price that does not reflect the true cost structure of the market can send an incorrect entry and exit signal. In addition to potentially sending distorted investment signals, generators that self-commit may displace other generators who would have otherwise been committed and earned energy market revenue. This could cause generators that should have earned profits to mount losses. These losses may subsequently incent more generators to self-commit, or cause a generator to retire who would have otherwise been profitable—either case results in a distorted investment signal. In short, sending the right price signal is critical, but so too is ensuring those who warrant the revenue—receive it.

[32] Projected revenues would be based on estimated forward prices.

[33] Mothballed generators are not used to produce electricity currently but could produce electricity in the future. Additionally, generators can be made available for reliability only.

4 UNIT COMMITMENT AND DISPATCH PROCESSES: EMPIRICAL FINDINGS

This section includes information and analysis regarding the pervasiveness of self-commitment, and then discusses generator start-up parameters and capacity factors.

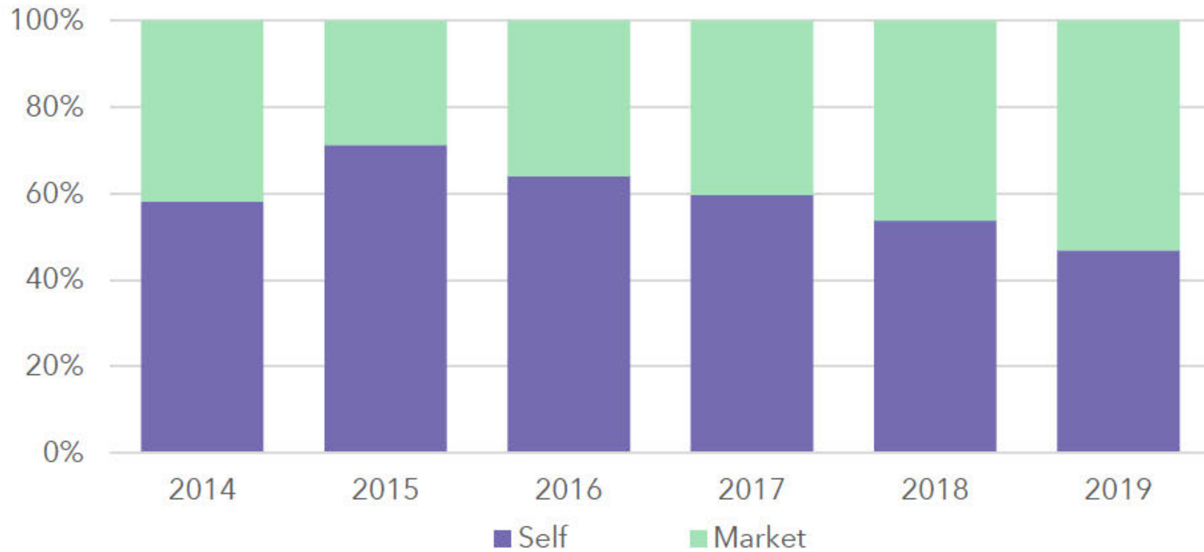
Key takeaways from this section include:

- The volume of self-committed megawatts declined over the study period, but remains nearly half of the total megawatt volume produced in the day-ahead market.
- Resources with long lead times and/or high start-up costs tend to self-commit instead of market-commit.
- Units that self-commit generally have much higher capacity-factors than those who market-commit. However, capacity factors by commitment status differ substantially by fuel type.

4.1 UNIT COMMITMENT – COMMITMENT STATUS

Figure 4—1 shows the percentage of day-ahead economic dispatch megawatts by commitment type over the study period.

Figure 4—4 Percentage of megawatts dispatched by commitment status



The volume of self-committed megawatts has declined over the last several years, but remains nearly half of the total dispatch megawatt volumes. In other words, nearly half of the energy produced was from a resource that was not selected by the day-ahead market's centralized unit commitment process.

While a relatively small percentage[34] of the self-committed megawatts were block-loaded,[35] many self-committed resources have operating parameters that include non-zero economic minimums.[36]

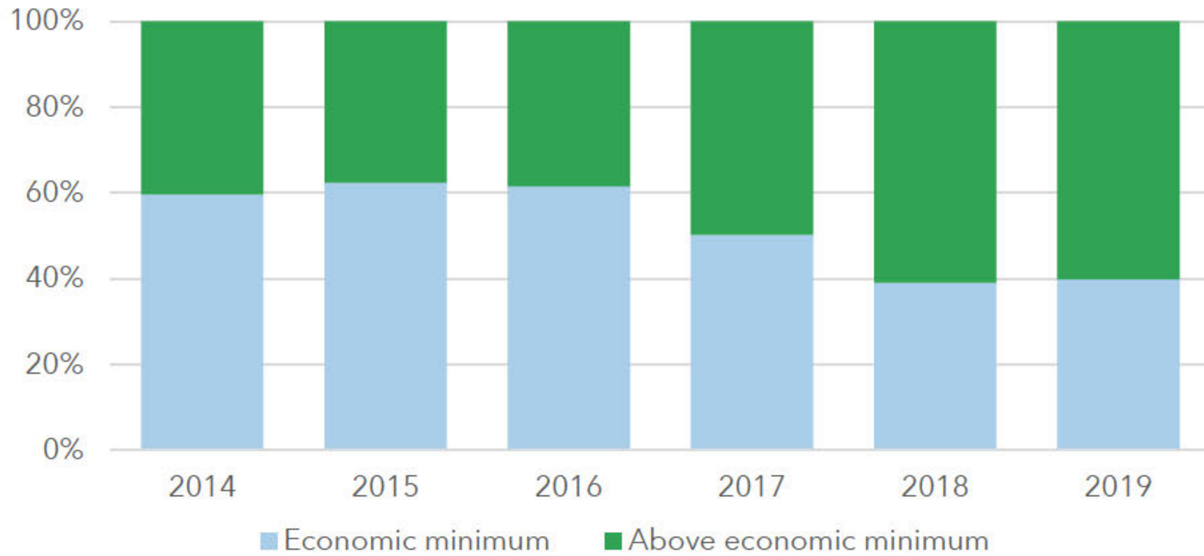
Even though resources are self-committed in the market, there also tends to be economic capacity above minimum that the market can dispatch. Figure 4—2 shows the percentage of self-committed dispatch megawatts above economic minimums.

[34] Over the study period, block loaded self-committed resources averaged about six percent of total self-committed volume.

[35] Block-loaded resources self-schedule by submitting one point offer curves, where economic dispatch range is zero, i.e. where economic minimum and economic maximum values are identical.

[36] Integrated Marketplace Protocols, Exhibit 4-6: Resource Limit Relationships, "Minimum Economic Capacity Operating Limit"

Figure 4—5 Percentage of self-committed megawatts dispatched above economic minimum



While the trend is decreasing, economic minimums amount to roughly forty percent of all self-committed dispatch megawatts.

4.2 UNIT COMMITMENT – FUEL TYPE

Resource fuel type is a useful classification of resources. Generally, the operating parameters and economics tend to be similar among units of the same fuel type. Operating parameters tend to be physical or time-based and include items like ramp rate, minimum run time, and lead time. Economic parameters include operating cost. In auction based ISO/RTO markets, the capital/fixed cost[37] portion is generally recovered through market revenues and public service commission rate cases, whereas allowable fuel and short-term maintenance cost[38] is incorporated directly into energy market offers.

In the absence of market power, the centralized unit commitment optimization uses the suite of unmitigated offers when it chooses the lowest cost generators. In general, a low (operating)

[37] Capital cost is also referred to as fixed cost (there is also fixed overhead & maintenance).

[38] Operating cost is also referred to as variable cost.

cost position on the supply curve comes at the expense of high fixed costs. Because fossil fuel generators tend to be quite levered to the price of fuel, the tradeoff between capital cost and operating cost can change if fuel prices decline significantly. This means that each generator's cost position can change, perhaps dramatically, based on fuel prices.

Figure 4—3 shows the percentage of self-committed dispatch megawatts by fuel type by year. Over the study period, the largest portion of self-committed dispatch megawatts sourced from coal units. Coal self-committed megawatts generally exceed the size of the second largest fuel type by a factor of more than four to one.

Figure 4—6 Percentage of self-committed megawatts by fuel type

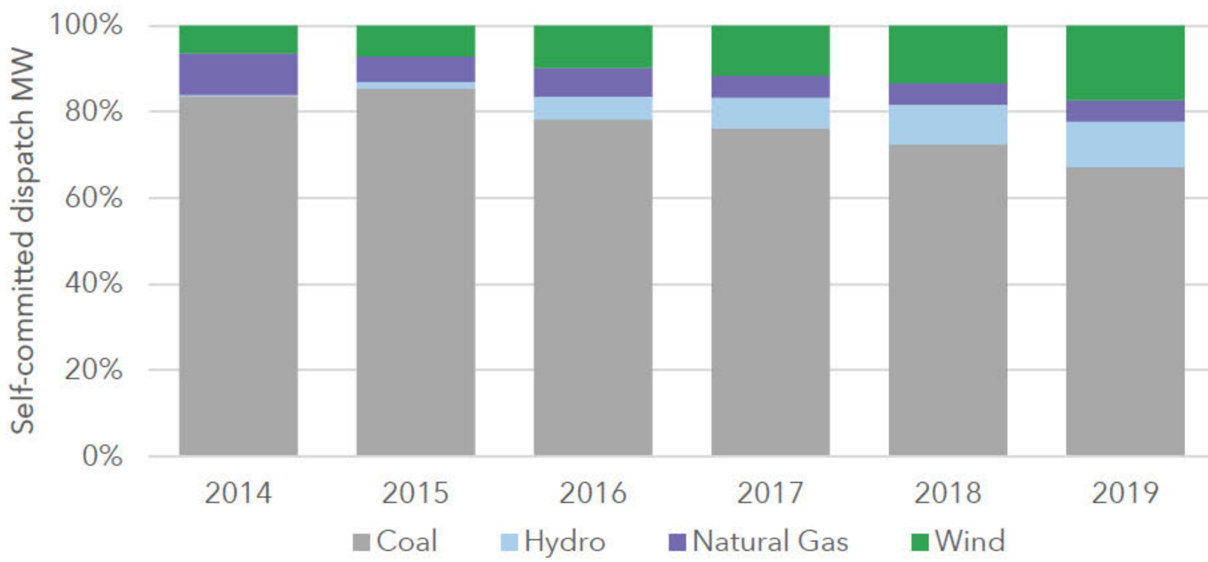


Figure 4—4 shows the percentage of market-committed dispatch megawatts by fuel type by year. Over the study period, the largest portion of market-committed dispatch megawatts sourced from natural gas units. However during the first year of market operation, coal units made up the largest share of market-committed megawatts.

Figure 4—7 Percentage of market-committed megawatts by fuel type

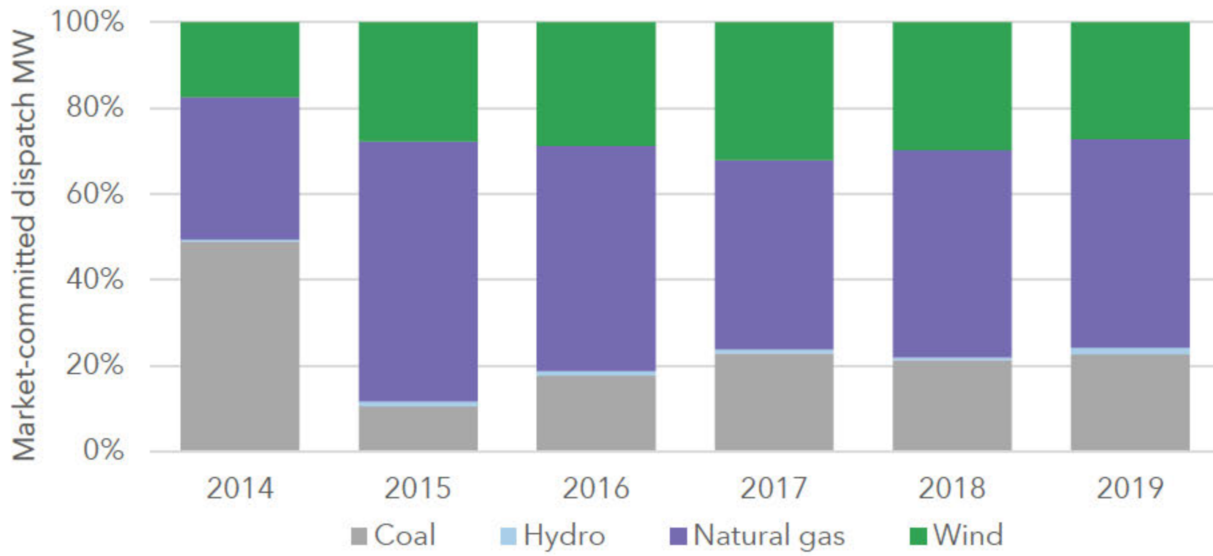
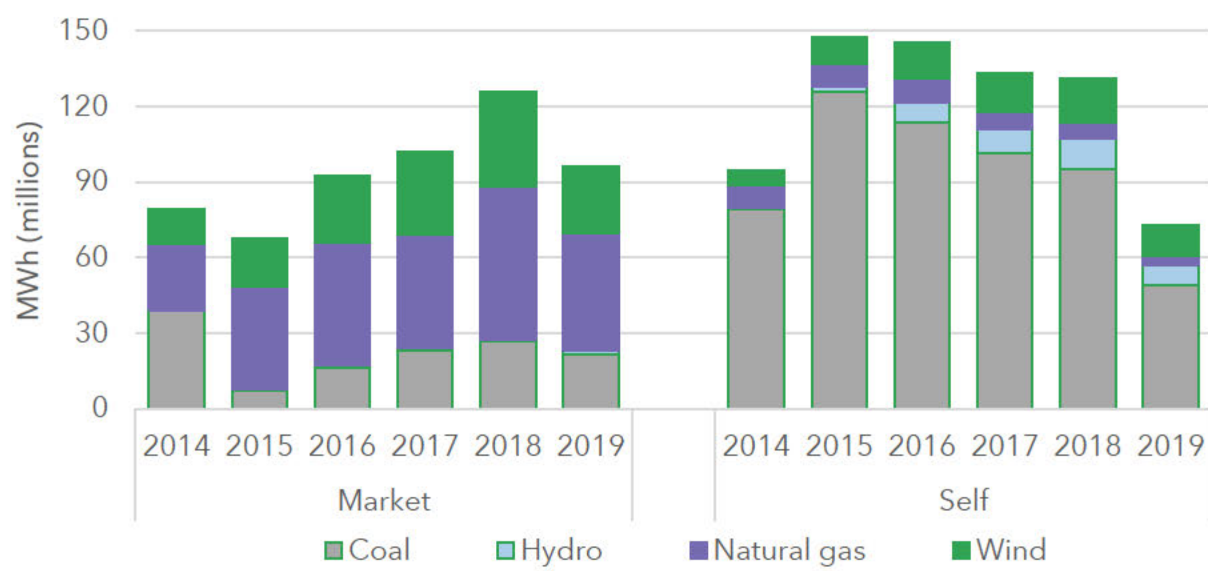


Figure 4—5 shows dispatch megawatts by fuel type by commitment type for each year of the study period.

Figure 4—8 Dispatch megawatt hours by fuel type by commitment type



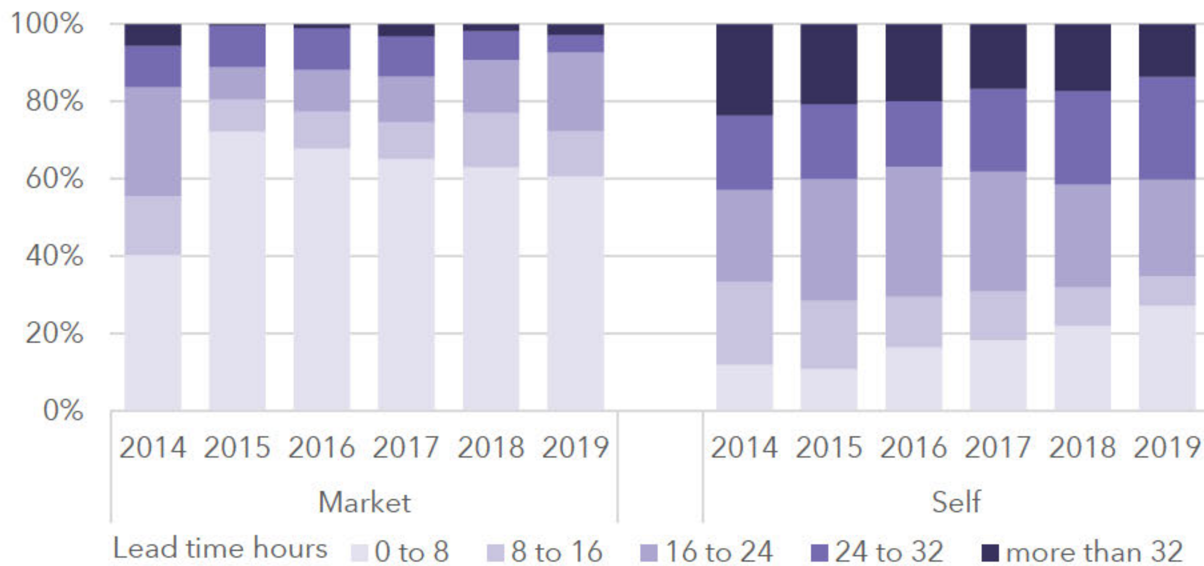
For the total period of March 2014 to August 2019, the magnitude of coal self-committed dispatch megawatts essentially equaled the total dispatch megawatts from all market-committed resources over the same period. In 2015 and 2016, self-committed coal greatly exceeded market commitments. However, as seen in 2019, self-committed coal megawatt hours, while still quite large, do not exceed market committed megawatt hours.

4.3 UNIT COMMITMENT – START-UP TIME

Resource lead times, also called start-up times, are time based operational parameters that vary widely by fuel type. In the Integrated Marketplace, resources can submit three different lead times: cold, intermediate, and hot. Thermal resources generally have longer lead times when they are cold as opposed to when they are hot. In the following section, we examine lead times by commitment status and fuel type.

Figure 4—6 shows the relationship between commitment status and start-up time.

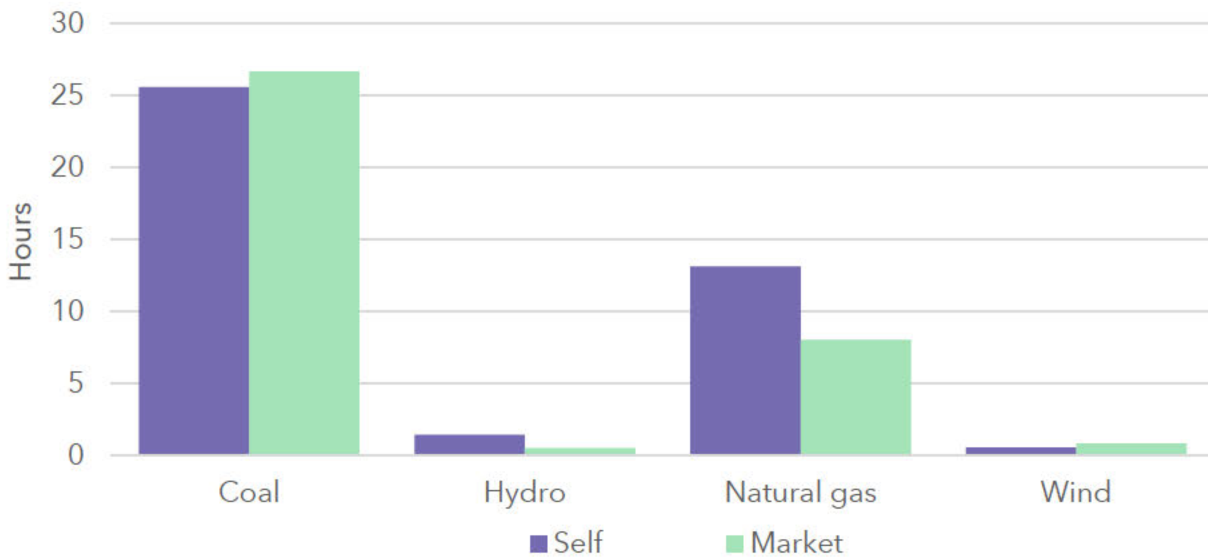
Figure 4—9 Lead time hours by commitment status



Self-committed resources tend to have longer lead times than market-committed resources. Because centralized unit commitment must observe constraints other than cost, it may not select a unit even if that unit's offer falls below the marginal resource.

Coal units have the longest cold start-up time, followed by natural gas. Figure 4—7 shows the dispatch megawatt weighted cold start-up time by fuel type by commitment type

Figure 4—10 Dispatch megawatt weighted lead time by fuel type by commitment status



Natural gas generators have the largest difference in start-up times between self-committed and market committed resources compared to other resources. Coal resources show relatively little deviation in their cold start-up time.

4.4 UNIT COMMITMENT – START-UP COST

Start-up cost is submitted in terms of dollars per start.[39] These parameters also vary widely by fuel type. Like start-up time, resources can submit three different start-up costs: cold, intermediate, and hot. Thermal resources generally have more expensive start-up costs when they are cold, as opposed to when they are hot. Additionally, start-up costs are non-convex which makes it hard for the market clearing algorithm to achieve an optimum solution.[40] However, when price taking behavior combines with good information, the market's efficiency can be improved.[41] In the following section, we examine start-up cost by commitment status and fuel type.

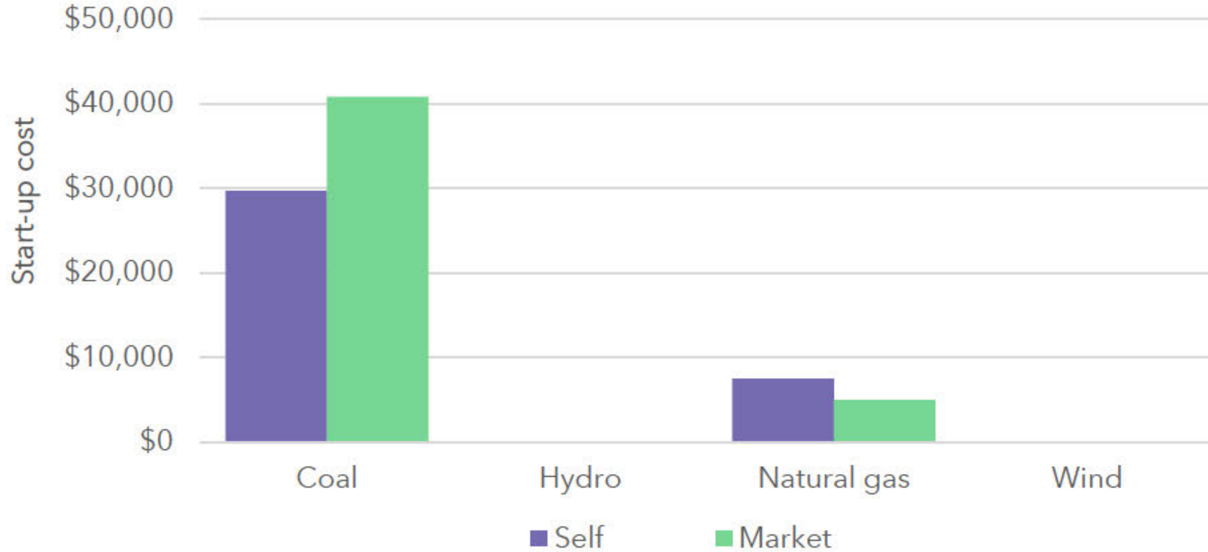
[39] Integrated Marketplace protocols, G.2.6.1 Start- Up Offer Definitions

[40] https://www.ferc.gov/legal/staff-reports/2014/AD14-14-operator-actions.pdf

[41] Steven Stoft, Power System Economics, p.55

Coal units have the highest cold start-up cost by more than a factor of five over the next highest start-up cost fuel type as seen in Figure 4—8. Coal start-up costs and gas start-up costs correlate strongly with gas prices.[42]

Figure 4—11 Dispatch megawatt weighted start-up cost by fuel type by commit status



Unlike start-up time, start-up cost differs materially for both coal and natural gas resources by commitment type. The difference between the market-committed cold start-up cost of coal and natural gas is even more significant than the relationship called out in Figure 4—7. Interestingly, market status based coal start-up costs exceed the start-up costs of self-committed resources. In market status, the cold start-up cost of coal exceeds that of natural gas by a factor of more than eight to one.

4.5 UNIT COMMITMENT – START-UP OFFERS

Start-up offers are generally representative of the cost that a market participant incurs when starting a generating unit from an off-line state to its economic minimum as well as the cost to eventually shut the unit down. These offers are submitted in terms of dollars per start.

[42] Over the study period, the correlation between natural gas start-up costs and Henry Hub gas prices is 78 percent, whereas the correlation between coal start-up costs and Henry Hub gas prices is 65 percent.

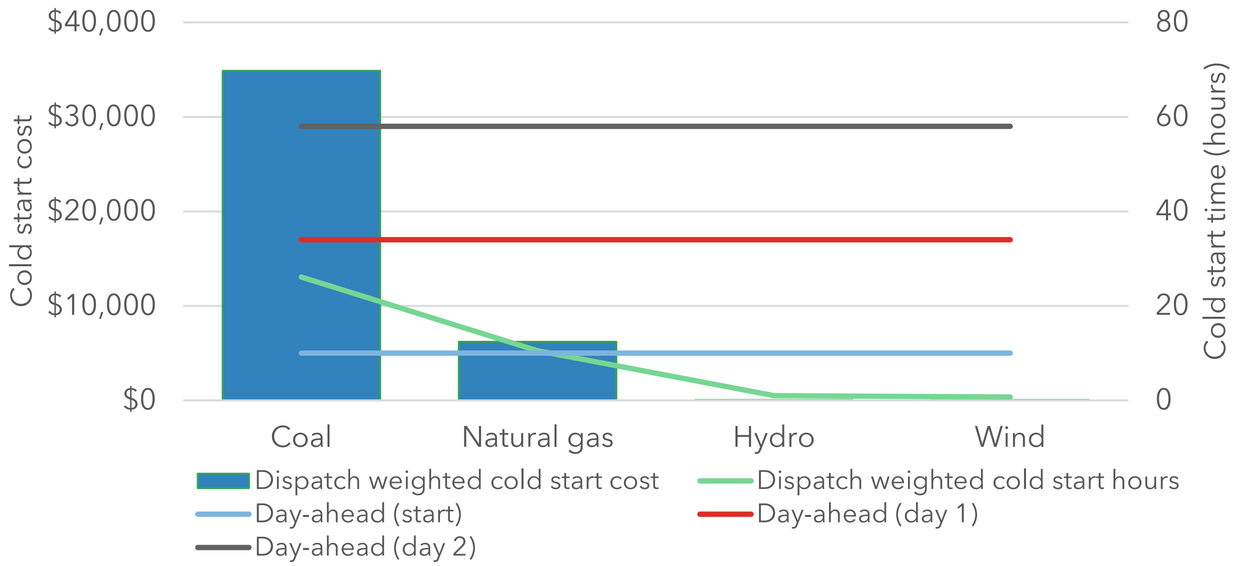
However, the optimization evaluates the offer in dollars per start per hour. The start-up cost is optimized and later amortized over the lesser of the resource's minimum run time or the number of hours from start time through the end of the day-ahead market window.[43]

While the financially binding day-ahead market covers only one operating day, the day-ahead market optimizes over a two-day window – the operating day and the next operating day. However, only the results from day one of the unit commitment solution feed forward to the economic dispatch algorithm. The results from the second day of the optimization are non-binding and are not used for commitment purposes. The two-day optimization helps prepare for the following day's morning ramp and attempts to prevent any unnecessary starting and stopping of units from one day to the next.

Figure 4—9 compares cold start time and cold start cost (y-axes) by resource fuel type (x-axis). The horizontal reference lines (blue, red, black) call out various periods in the day-ahead market window. Hour 10 represents the time from the posting of day-ahead market results to the beginning of the day-ahead market day. The second line at hour 34 represents the end of the first day-ahead market day and the beginning of the second day-ahead market day. The third line at hour 58 represents the end of the second day-ahead market day. The blue bars relate to the left axis and the lines relate to the right axis. These two inputs are used in the construction of the start-up offer.

[43] The day-ahead market window covers two days.

Figure 4—12 Cold start time and cold start cost by resource fuel type



Many of the units with high start-up costs have minimum run times that extend past the day-ahead market window. If the optimization evaluated start-up costs over each resource's full minimum run time, their start-up offers would be more competitive with shorter lead-time resources. This issue compounds for those resources with long lead times and high start-up costs. Because these units cannot come online until much later than the first hour of the day-ahead market day, their start-up cost is optimized over even fewer hours.

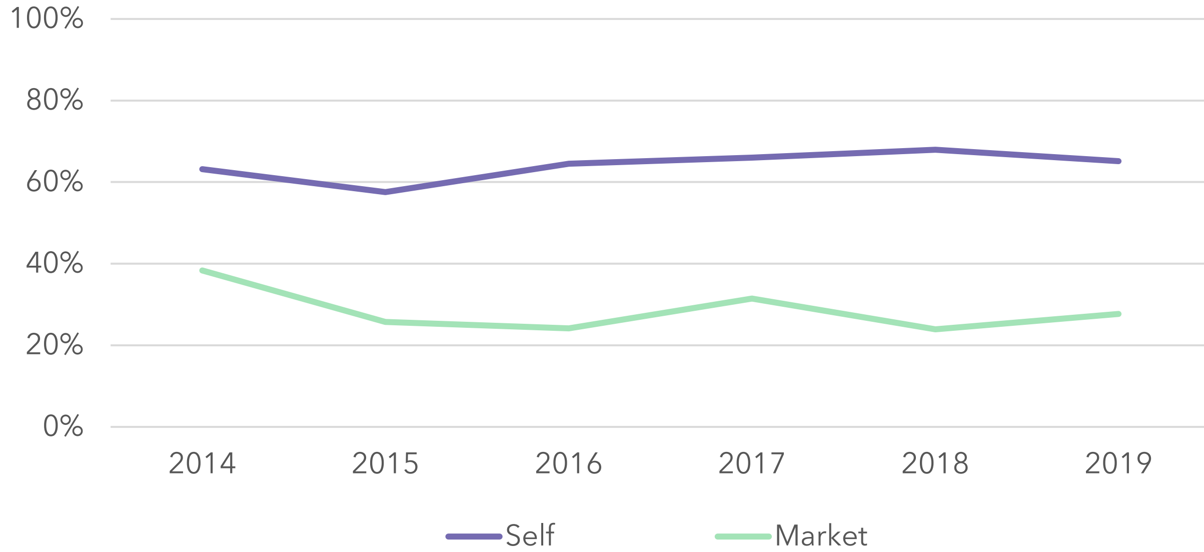
4.6 UNIT COMMITMENT – THE CAPACITY FACTOR

Because of the relationship between fixed cost and variable cost inherent in power generation, capacity factors are a central input when calculating a generator's long run average cost and by extension their long run economic viability.

A capacity factor is the ratio of energy output for a given period (usually a year) to the maximum possible energy output over the same period. The more energy a resource produces, the lower its fixed cost per unit of production. The relationship between fixed cost and marginal cost is often referred in other industries as operating leverage. If fixed costs are significantly larger than variable costs, a firm will exhibit high operating leverage.

The higher the operating leverage the more profit earned from an incremental sale and the more lost from a lost sale. The capacity factor is effectively the ratio of sales to potential sales for power plants.

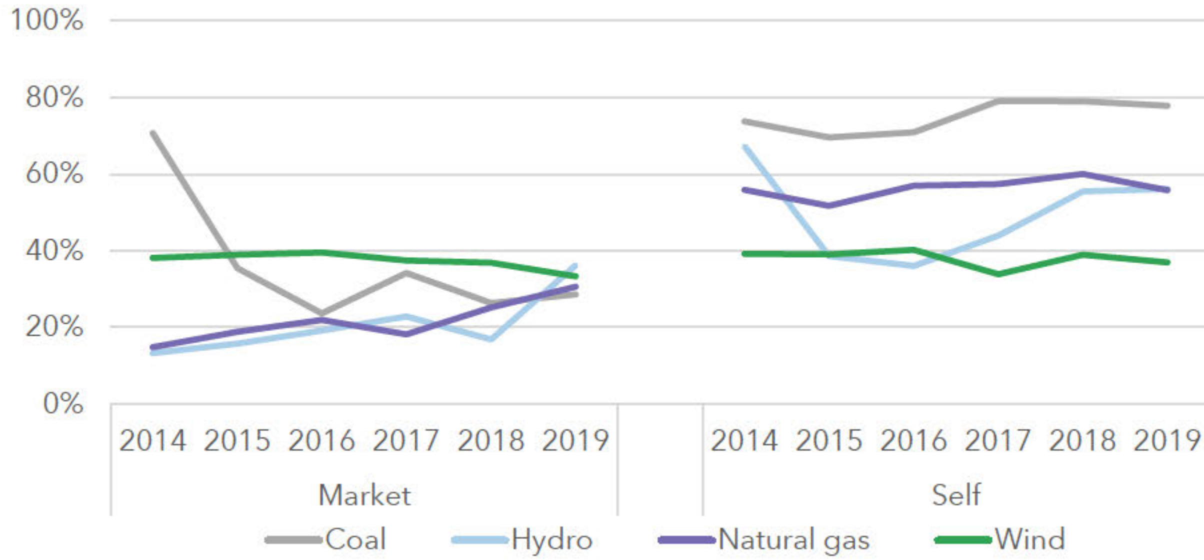
Figure 4—13 Capacity factors by commitment type



Over all resource fuel types, capacity factors roughly double when resources offer in self-status, as opposed to market-status.

Figure 4—11 shows the capacity factors by commitment type by fuel type. This figure shows that some fuel types (such as wind) have comparatively similar capacity factors irrespective of their offer status. However, some fuel types (such as coal and natural gas) have vastly different capacity factors when they are committed in market or self.

Figure 4—14 Capacity factors by fuel type by commitment type



Similar to capacity factors by fuel type, some turbine types have quite similar capacity factors when they are committed in market or self-status.

5 PRICE FORMATION

In this section, we build upon the price portion of the market feedback loop discussed earlier. Specifically, we provide empirical information and analysis reflecting the prices and production costs over the study period.

Key points from this section include:

- Over the study period, at least one self-committed unit was marginal in roughly 75 percent of the day-ahead market hours.[44]
- Over the study period, prices were systematically lower when at least one self-committed unit was marginal.
- In almost all cases, self-committed generators had lower revenues than market-committed generators because of negative congestion prices.
- In SPP's case, consumers and producers are not necessarily two distinct, organically separated groups.[45] This dynamic makes the impact of price levels and production costs less clear.

5.1 IMPACT OF SELF-COMMITMENT ON PRICE FORMATION

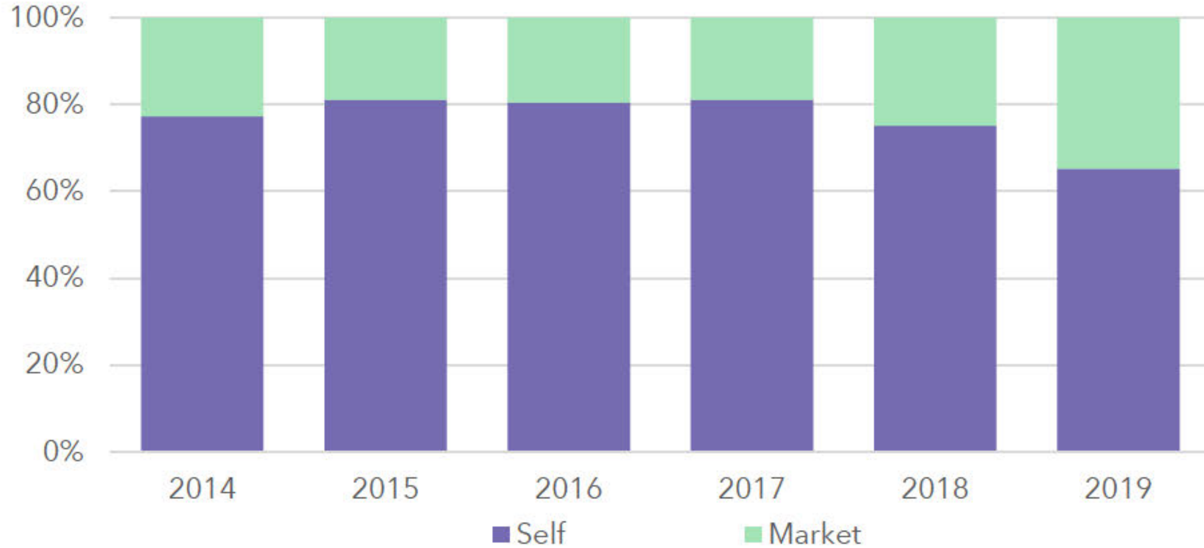
To quantify the impact of self-commitment on prices and price formation, we evaluate the frequency and magnitude of self-commitment in addition to the time it sets price. Self-committed resources can set price as many self-committed generators offer their incremental

[44] More than one resource can be marginal during a given period.

[45] The participants—primarily the investor owned utilities—who serve load may also own or control both generation and transmission assets. In fact, in 2018 investor owned utilities owned 53 percent of the total nameplate generation capacity in the SPP market.

energy into the market. Self-dispatched resources are resources that do not allow the market to choose their incremental energy output.[46]

Figure 5—15 Percentage of day-ahead hours by marginal resource by commitment type



Over the study period, at least one self-committed resource was marginal in substantially more than half of the day-ahead market hours. For the purposes of Figure 5—1, if during an hour, a single marginal generator was self-committed, that hour is classified as self. If only market committed generators were marginal during the hour, that hour is classified as market.

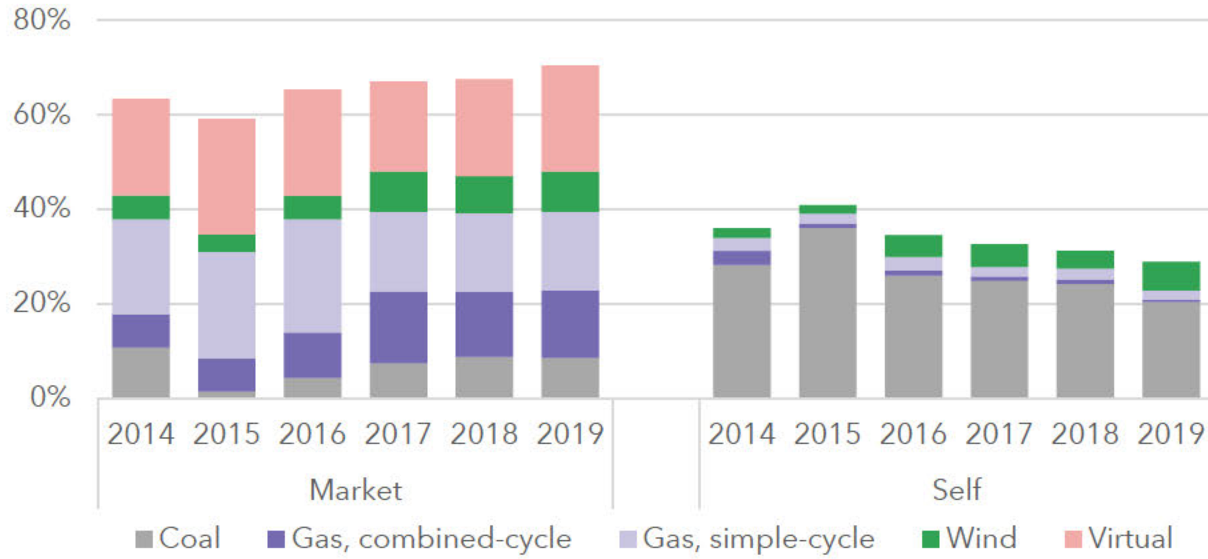
Even though self-committed generators are treated as price insensitive suppliers in the unit commitment process, these same generators can set the marginal clearing price if they provide the marginal unit of supply when dispatched above their economic minimum. These units may not have been committed by the centralized unit commitment had they been offered in market-status, and by extension, may not have otherwise been marginal. This is one of the reasons market participant's unit commitment decisions can affect price formation.

However, in any given hour, there is likely to be more than one marginal price setting resource because of the effects of transmission congestion. Figure 5—2 captures this effect. It looks at

[46] For example, non-dispatchable variable energy resources (NDVERs) are self-scheduled as opposed to self-committed. However, for the purposes of this analysis, we have including NDVER as self-committed.

all the marginal resources in the market and finds that over the study period, market-committed resources[47] were on the margin setting prices during roughly two-thirds of all instances in the day-ahead market whereas self-committed resources set prices during roughly one-third of all instances day-ahead.

Figure 5—16 Percentage of marginal hours by fuel type

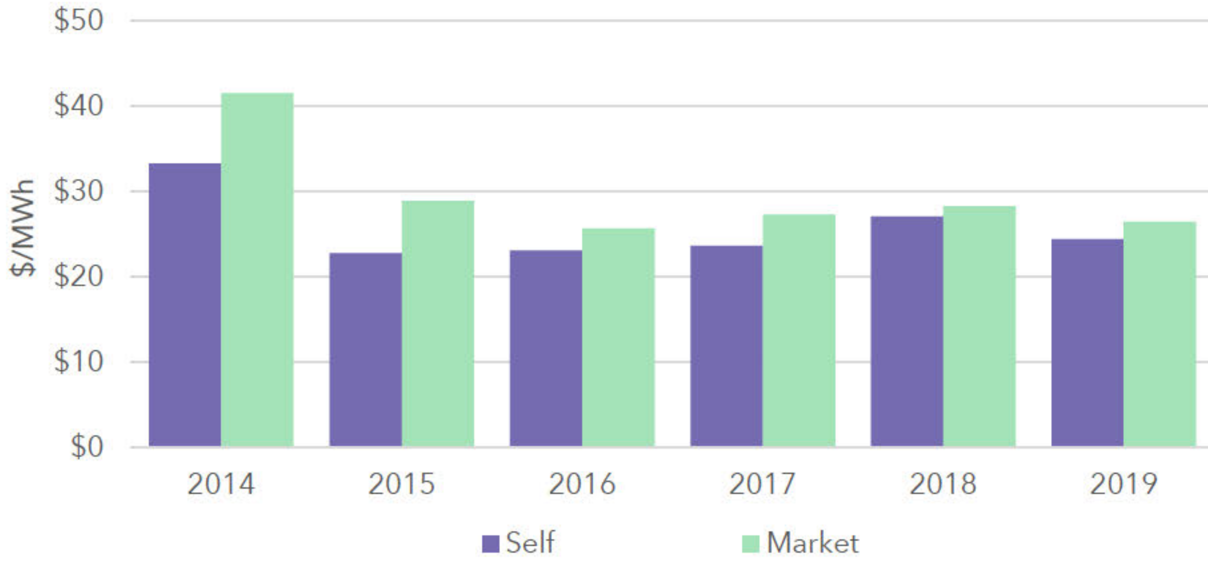


Of the market committed-units, wind, virtual, and combined-cycle gas resource types have increased their time setting prices on the margin, while simple-cycle gas and coal generators have decreased their time setting prices on the margin.

Of the self committed-units, coal dominates the time on the margin compared to all other fuel types. Wind on the margin continues to grow, whereas the frequency of coal on the margin, while still quite large, continues to decline.

[47] We have classified virtual transactions as market committed for the purpose of this analysis.

Figure 5—17 Average day-ahead system marginal prices by marginal unit commitment type



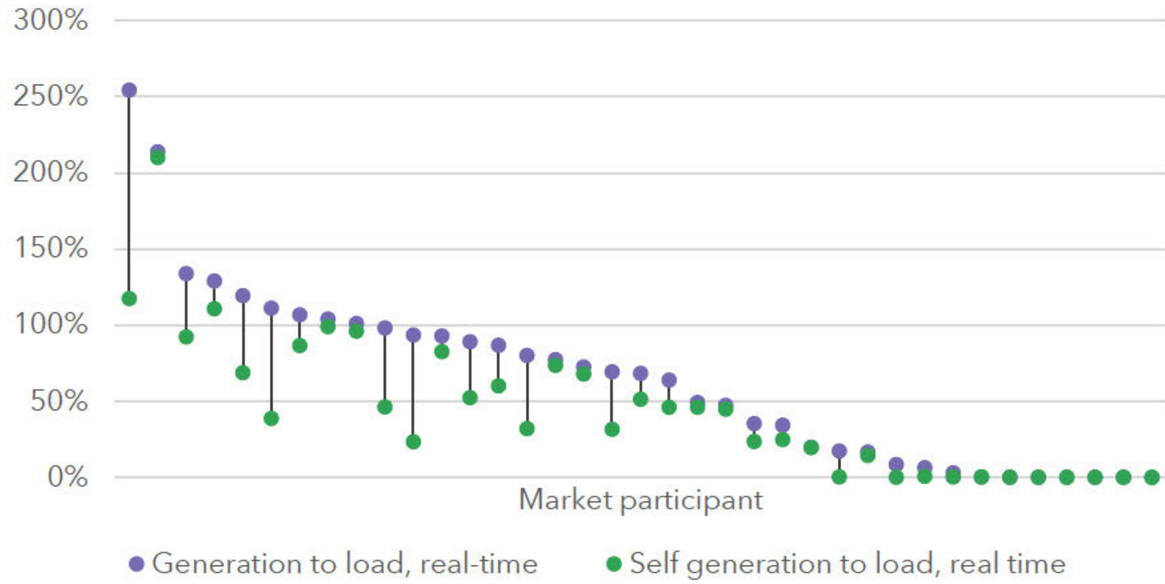
Over the study period, prices were systematically lower when at least one self-committed unit was marginal.

5.2 WHO PAYS?

SPP market participants have indicated in stakeholder meetings, that in a cost-of-service regulated market, when participants are vertically integrated, the load ultimately pays and therefore will benefit from lower prices and production costs. However, when participants are vertically integrated, the load is also the generation in terms of integrated ownership. Low prices do indeed benefit load, but they do not benefit generation. Because these entities are not distinct, and must carry generation capacity to meet their capacity obligation, the "who benefits" question with respect to the level of prices is nuanced.

Figure 5—4 highlights two things. First, it shows the level of generation produced by a participant relative to its load. Second, the figure shows the level of self-committed generation relative to its load.

Figure 5—18 Generation megawatts to load megawatts by commitment type



The purple dots above 100 percent line denote a market participant who produced energy in excess of its real-time load obligation. The inverse indicates a market participant who produced less than their real-time load. In a competitive market, it would be expected that some would produce more than their load and some would produce less, as lower cost resources would displace higher cost resources.

The green dots show the self-committed generation relative to load. The green dots above the 100 percent line denote a market participant whose self-committed energy production exceeded their corresponding real-time load. The inverse indicates a market participant whose self-committed units produced less than their real-time load.

The figure shows that there are three participants that self-committed more generation than their load. In this case, the participant would be selling self-committed generation to the market. Furthermore, the chart shows that some participants self-committed almost all of their generation (purple and green dot the same or very close) and that the majority of participants self-committed some generation. This highlights how difficult it is to determine who benefits from higher or lower prices.

5.3 CONGESTION

Congestion price signals incentivize the behavior of market participants. When locational marginal prices are elevated, generators in that particular pricing node earn more. Because every node in the system includes the system marginal price, the difference in locational marginal prices stems mostly from the marginal congestion component of the locational marginal price.

Congestion affects all resources. However, in the SPP market, it tends to affect resources differently as seen in Figure 5—5. Natural gas resources tend to have higher prices as a result of congestion, while coal and wind resources tend to have dramatically lower prices. The congestion profile is more balanced for units that market-commit. Some market generators earn more than the system marginal price and some earn less, whereas generators who self-commit almost always earn less than the system marginal price.

Figure 5—19 Congestion dollars by fuel type, by commitment status

Additionally Figure 5—5 brings to light an additional price signal. Congestion prices, similar to energy prices, provide feedback to market participants. When congestion reduces generator revenues, the market's general message is twofold: generators are incented to do less of what they are doing in the short-run and generators are incented not to build additional generation in the long run. The market also uses congestion to convey information to transmission owners.

In this case, if participant behavior does not change, transmission owners will likely be incented to build additional transmission infrastructure. When generator congestion is positive, the market generally conveys the opposite information to market participants. As an extension of our message in Section 3, self-commitment also blurs the congestion price signal.

In Figure 5—5, the green bars represent the market commitments and is more desirable than the purple bars because the unit commitment process committed that resource, not the market participant. What we do not know, however, is if the market-committed unit earned its commitment to offset a constraint created or enhanced by a self-committed unit. The purple bars below zero might also represent the market software attempting to incent different commitment behavior.

Both generators and loads are assessed congestion costs. Generators pay congestion through reductions in the locational marginal price. Loads pay congestion through increases in the locational marginal price. On balance, we observe that generation has been assessed more congestion than load in the Integrated Marketplace.[48]

Because self-commitment affects congestion, it also affects SPP's congestion hedging market. One way of scaling this impact is to compare average transmission congestion right (TCR) profitability by marginal unit commitment type by hour, which is the same classification methodology used in Figure 5—1.

[48] MMU Quarterly State of the Market Report, Spring 2019, Special Issues

Figure 5—20 Transmission congestion right revenue per megawatt by marginal unit commitment status

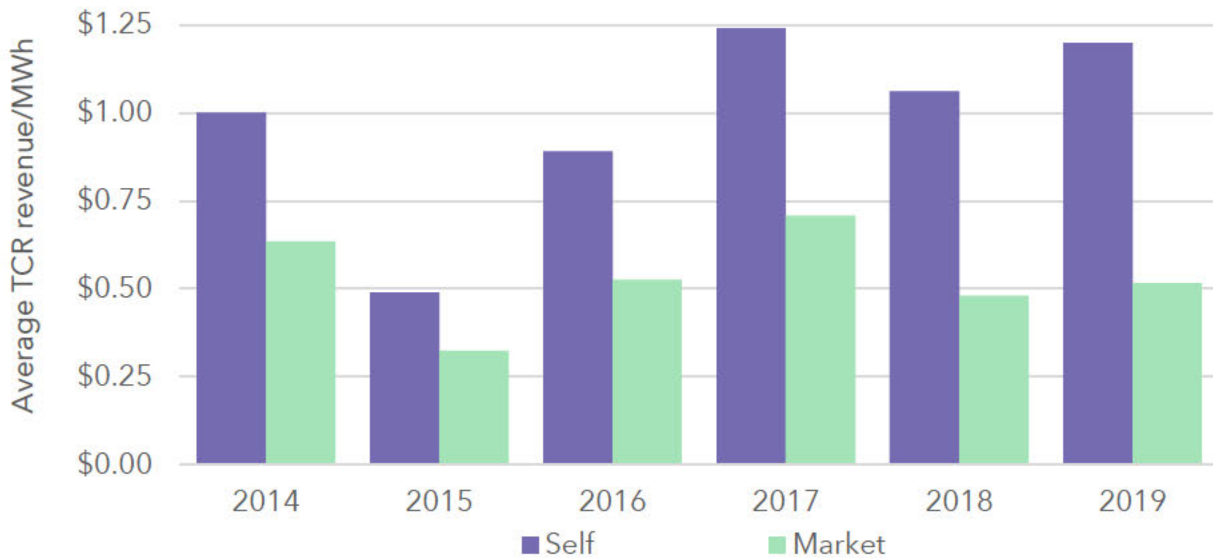


Figure 5—6 shows the revenue per megawatt of transmission congestion rights[49] was significantly higher when at least one self-committed unit was marginal. Our general takeaway is that in hours when at least one self-commit unit is marginal the system is more congested when compared to hours where only market-committed units are marginal. By extension, the congestion revenues from congestion hedges increase during hours where at least one self-committed unit is marginal.

[49] Figure 5—6 includes self-converted transmission congestion rights, long-term transmission congestion rights, and the positions purchased and sold in the various auctions.

6 SELF-COMMITMENT SIMULATIONS

In this section, we perform three simulations to study the effect of market committing resources that participants currently self-commit in the day ahead market.

6.1 OVERVIEW

To study the impact of self-commitment on market results, we re-solved the Integrated Marketplace's day-ahead market. In our study, we executed three scenarios using the effective version of the actual Integrated Marketplace software associated with each operating day. In each of the scenarios, we simulated the centralized unit commitment and economic dispatch optimizations.

In our first scenario, we validated our process by rerunning the original day-ahead market and compared the validation results to the original results. The validation cases were then used as the base inputs to scenarios two and three.

In scenario two, we changed the offer status from self to market for all resources that originally elected self-status. We also turned off all resources, so the market could make all unit commitment and dispatch decisions without optimizing the generators already producing power. Scenario three builds on scenario two, and includes the same input modifications in addition to reducing lead times to simulate extending the day-ahead market optimization window.

Findings from the simulations include:

- The key to reducing self-commitment while not increasing costs is multi-day economic unit commitment.[50]

[50] Our position supports the findings of The Holistic Integrated Tariff Team's Reliability Recommendation #3 – Implement Marketplace enhancements. Specifically, Multi-day market.

- Increasing the optimization window by another 24 hours allows the market to more effectively optimize resources with long start-up times. This enhancement combined with a reduction in self-commitment, would likely benefit ratepayers by reducing production costs in addition to sending more clear investment signals.
- If the optimization window is not lengthened, and self-commitment is eliminated, investment signals would be more clear, but production costs would likely increase.

6.2 STUDY DETAILS

6.2.1 SCENARIO 1 – VALIDATION SCENARIO

The purpose of the validation scenario is to determine the legitimacy of our testing framework. As with many electricity markets, SPP's software uses a mixed-integer optimization program that solves for optimal commitment and dispatch. Because of the nature of this type of software, it is not always possible to reproduce the original results even with identical inputs. For this reason, we rejected several market days from our study where the hourly production costs fell outside our tolerance when compared to the original market solution.[51]

Because of simulation run-time constraints, the study period includes one week of each month from September 2018 through August 2019. In addition to the data being readily available, this period also includes the different annual seasons and a wide variety of market conditions. The testing criteria, sample size, and results of our validation scenario gives us confidence in our process.

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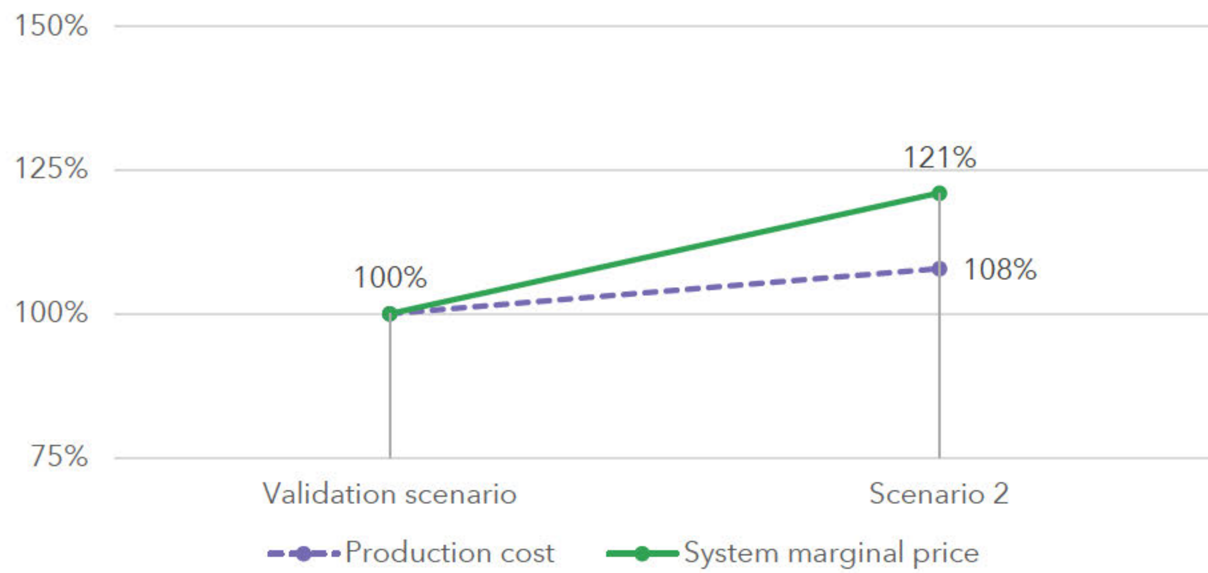
[51] We discarded market days for which the coefficient of determination of hourly production costs between the original market solution and the validation solution were less than 95 percent, representing about eight percent of market periods simulated. The remaining days averaged 99.5 percent coefficient of determination between the original solution and the validation solution. When simulating a market day, small differences in the calculation of hourly commitment or dispatch levels can compound in subsequent hourly solutions, leaving the final solution set for a day significantly different from the original market solutions.

6.2.2 SCENARIO 2 – UNITS CHOOSE "MARKET"

A number of changes were made to the validation data set prior to executing scenario two. Resources that were originally offered to the day-ahead market in self-status were set to market-status, de-committed at the start of each study period, and treated as having met their minimum down time before each continuous study period to allow for immediate commitment by the market engine.

Figure 6—1 shows the results of scenario two in terms of change in prices and production cost relative to the validation scenario.

Figure 6—21 Scenario 1 vs Scenario 2, system marginal price and production cost



In scenario two, marginal energy prices increased in excess of twenty percent, which was more than $6/MWh. Also in scenario two, production costs increased roughly eight percent, or more than $22,000 per hour. The results suggest that the current market software cannot more efficiently commit and dispatch all available units in the absence of self-commitment. As we discussed earlier in this report, the length of the optimization period is one of the software's limitations. As such, scenario two represents the market software's optimal solution given the current market structure if all resources did not self-commit.

6.2.3 SCENARIO 3 – UNITS CHOOSE "MARKET" AND OPTIMIZE LONG LEAD TIMES

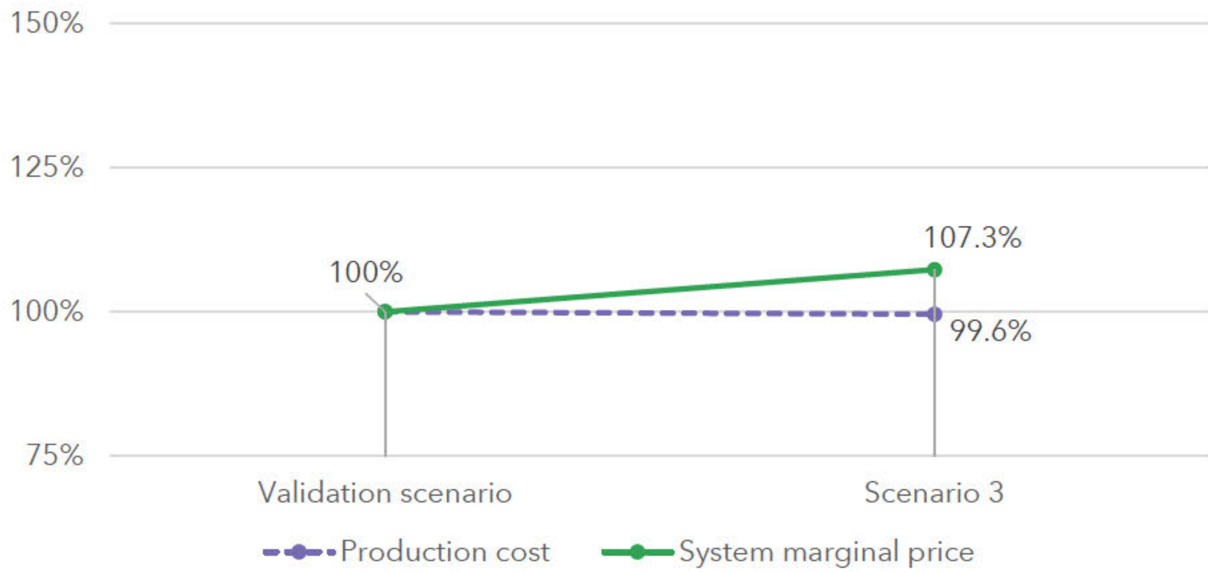
Scenario three expands on scenario two by simulating the lengthening of the optimization period of the day-ahead market. Effectively, this scenario attempted to create a multi-day economic unit commitment. This enhancement directly addresses one of the current limitations of the market software – optimizing long-lead time resources. As we mentioned in the unit-commitment section, long-lead time resources, especially those with high start-up costs, tend to be uncompetitive, in part, because of the duration of the current market optimization window.

Lengthening the optimization window includes long-lead resources that would otherwise be excluded from the optimization and decreases the hourly-amortized start-up amount, making these resources more competitive. Lengthening the optimization window by an additional day resolves the majority of these cases.

The length of the optimization window is not configurable in the current software. Therefore, to simulate an increased optimization window, we decreased the start-up times of resources with startup times greater than 23 hours to 12 hours. This change allows the current day-ahead market software to commit the resource in a manner which simulates the presence of a lengthened economic commitment mechanism.

Figure 6—2 shows that in this scenario prices increased, but production cost decreased when compared to the validation scenario.

Figure 6—22 Scenario 1 vs Scenario 3, system marginal price and production cost

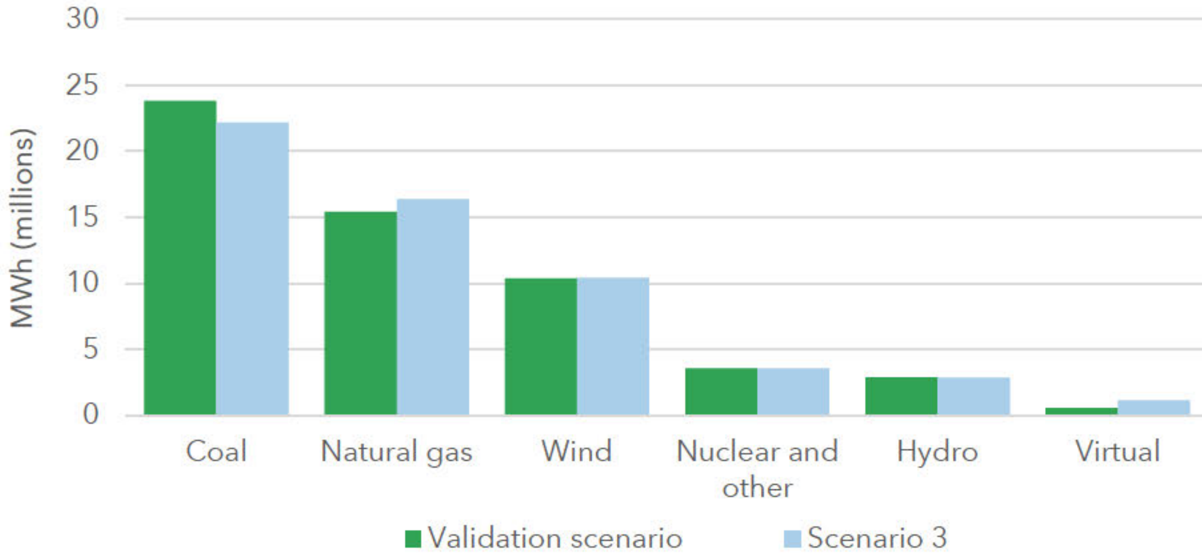


On average in every hour of the study period, system marginal prices were higher when all units market-committed. This is the same directional result as in scenario two and a predicted result based on the change in the supply curve as discussed in section two. The average system marginal price over all hours increased more than seven percent, about $2/MWh on average. The average production cost change over all hours decreased roughly one-half of one percent, or $1,750 per hour.

These results suggest that a purely economic commitment model, if able to consider and commit long lead-time resources, would lead to somewhat higher market prices and potentially more accurate investment signals while potentially reducing production costs. Given this result, we would prefer scenario three to scenario two.

Not only did the optimization change prices, it also changed dispatch quantities. Figure 6-3 shows the change in dispatch megawatts between scenario three and the validation scenario.

Figure 6—23 Scenario 1 vs Scenario 3, dispatch megawatts by fuel type



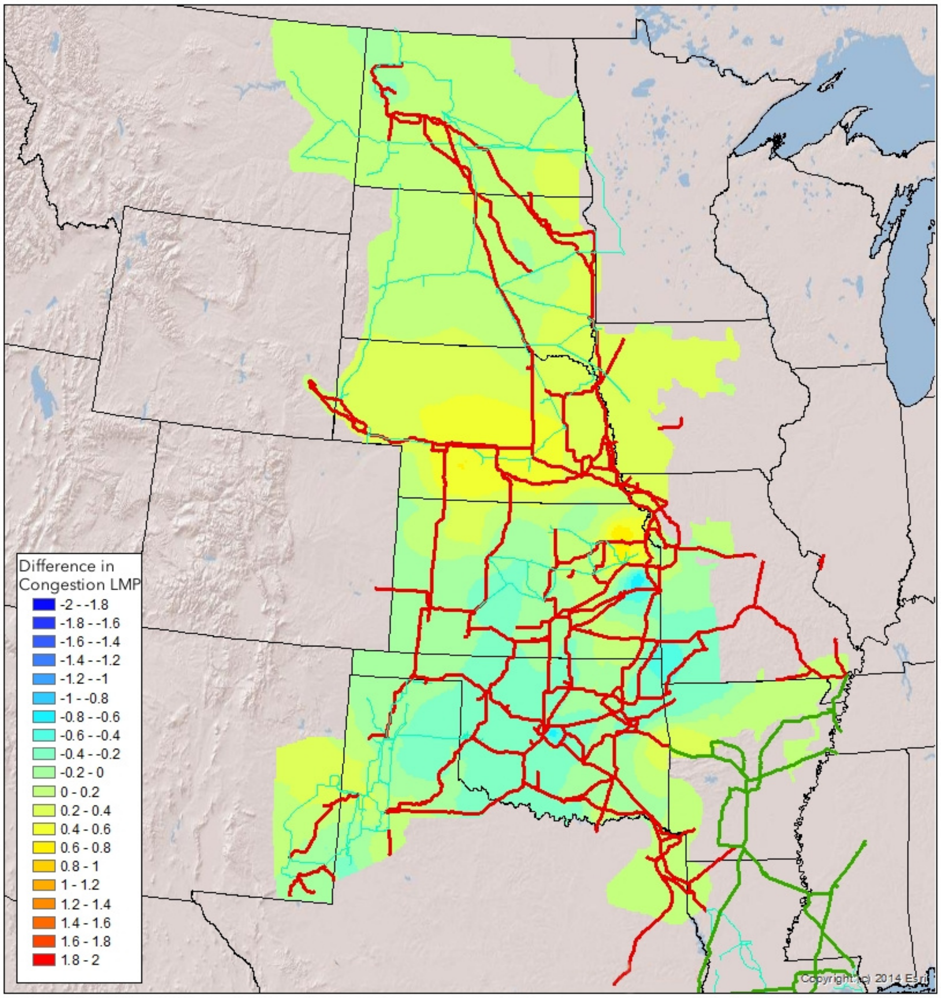
In scenario three, coal energy awards decreased seven percent, when compared against the validation scenario. Natural gas and virtual supply replaced the majority of the reduction in coal. Because changes in self-commitment affect prices, and virtual participation is based on projected prices, we expect virtual trading behavior would also change. However, we are unable to simulate how virtual participants might change their behavior in this analysis.

Any structural change to the SPP markets would likely cause a redistribution of marginal generation that can have far-reaching impacts on congestion, local pricing, and congestion hedging products. In order to visualize the net congestion differences between the original market solution and this scenario, we graphed the difference in the marginal congestion component (MCC) of the locational marginal price over the study period.

Generally, congestion reflects supply and demand relationships between producers and consumers in a given area. When an area is oversupplied with generation, congestion prices tend to be lower. Likewise, an area undersupplied with generation will tend to have higher congestion prices. This framework translates into the figure below.

Figure 6—4 shows the change in congestion between scenario three and the validation scenario. Higher congestion prices (yellow and orange) indicate increase in prices from the validation scenario to scenario three, and lower prices (green and blue) reflect price reductions in scenario three relative to the validation scenario. Ultimately, changes in congestion prices ranged between a decrease of approximately $1/MWh and an increase of approximately $1/MWh over the study period.

Figure 6—24 Scenario 1 and Scenario 3 comparison, difference in congestion costs



The majority of the supply reductions are in the coal-dominated regions of the footprint, which leads to a slight increase in congestion pricing in those areas. Accordingly, much of the replacement energy committed and dispatched to serve the day-ahead demand comes from gas-fired generation in the southern portion of the footprint, leading to a slight reduction in congestion pricing around those units.

7 CONCLUSION

Self-commitment represents a significant portion of the transaction volume in the Integrated Marketplace, and while it cannot be eliminated completely, the practice can likely be reduced substantially. By reducing self-commitment, prices and investment signals will likely be less distorted. A smaller distortion will likely help market participants make better short-run and long run decisions, which tends to coincide with improved profit maximization. Enhanced profit maximization combined with effective regulation and monitoring will likely lead to ratepayer benefits in the form of cost reduction.

While we have seen gradual reductions in self-commitments over the last few years, generation from self-committed generators still represent about half of the generation in the SPP market. Given our results, we recommend that the SPP and its stakeholders continue to find ways to further reduce self-commitments. Many resources have switched from self-commitment to market status over the past few years, and it is possible that many more could switch without any market enhancements.

However, as we presented in our simulations, simply eliminating self-commitment without any additional changes could result in an increase in total production costs. This would not necessarily be an improvement when compared to today's results. However, when lead times were shortened to reflect an additional day in the market optimization and self-commitment was eliminated, producers were paid more and production costs declined.

The efficiency gain stems largely from an improvement in the optimization of nonconvex costs, specifically start-up costs. In the current construct, units with long lead times, high start-up costs, and long minimum run times may be uneconomic over a single day, but economic over a longer period. Extending the optimization period helps bridge this gap. However, as the optimization period lengthens, it must solve for variables further into the future where there is more uncertainty. However, empirical evidence suggests that the accuracy of wind and load forecasts remain acceptable over a two-day optimization window.[52]

For these reasons, and others covered throughout this report, we support the HITT recommendation of evaluating a multi-day optimization,[53] and see this as an enhancement that can improve market efficiency and help further reduce the incidence of self-commitment. Specifically, we recommend that SPP and its stakeholders consider a multi-day commitment period of two days to allow units to commit long lead time resources.

[52] Market Working Group Meeting Materials – February 2019 – 10.b.i.MultiDay Forecast_021919

[53] See footnote 50.

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Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

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SIERRA CLUB EXHIBIT 104

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Rebuttal Testimony of Michael Wilding in A.19-08-002

This exhibit is confidential pursuant to Protective Order 16-128 and is provided under separate cover.

PUBLIC UTILITY COMMISSION OF OREGON

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SIERRA CLUB EXHIBIT 105

Exhibit Accompanying the Opening Testimony of Ed Burgess

Selected Public Data Responses

Exhibit Sierra Club/105

Selected Public Responses to Sierra Club and OPUC Data Requests

1. PacifiCorp's First Supplemental Response to Sierra Club 1.3
2 PacifiCorp Response to Sierra Club Data Request 1.4
3. PacifiCorp Response to Sierra Club Data Request 1.10
4. PacifiCorp Response to Sierra Club Data Request 1.24
5 PacifiCorp Response to Sierra Club Data Request 1.29
6. Redacted PacifiCorp Response to Sierra Club Data Request 1.31
7. PacifiCorp Response to Sierra Club Data Request 3.5
8 PacifiCorp Response to Sierra Club Data Request 3.11
9. PacifiCorp Response to Staff Data Request 6
10 PacifiCorp Response to Staff Data Request 8
11. PacifiCorp Response to Staff Data Request 9
12 PacifiCorp Response to Staff Data Request 11
13. PacifiCorp Response to Staff Data Request 53
14. PacifiCorp Response to Staff Data Request 55
15. PacifiCorp Response to Staff Data Request 107

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Sierra Club Data Request 1.3 – 1st Supplemental

Sierra Club Data Request 1.3

For each of the Company's coal-fuel units please provide the following cost assumptions as used in the 2019 IRP preferred portfolio, by year from January 2018 through the end of the analysis period:

(a) Hourly net generation (MWh)

(b) Operational or maximum available capacity (MW)

(c) Minimum economic available capacity (MW)

(d) Heat rate (MMBtu/MWh)

(e) Fixed operations and maintenance (O&M) costs (total $)

(f) Variable O&M costs (not including fuel cost) ($/MWh)

(g) Variable fuel cost – dispatch tier ($/MWh)

(h) Variable fuel cost – costing tier ($/MWh)

(i) Fixed fuel cost ($)

(j) Please explain any differences between assumptions as used in this NPC and the 2019 IRP, including the use of dispatch tiers, and commitment, if applicable.

1st Supplemental Response to Sierra Club Data Request 1.3

PacifiCorp continues to object to this request on the grounds that the information sought is outside the scope of this proceeding and that this request is not reasonably calculated to lead to the discovery admissible evidence. PacifiCorp's 2019 Integrated Resource Plan (IRP) preferred portfolio and the transition adjustment mechanism (TAM) serve very different functions and therefore the inputs to the different models may be different. Notwithstanding the foregoing objections, the Company responds as follows:

(a) The Planning and Risk (PaR) model stochastic studies in PacifiCorp's 2019 Integrated Resource Plan (IRP) does not provide hourly data output. Please refer to Confidential Attachment Sierra Club 1.3 1st Supplemental which provides monthly generation by coal unit.

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(b) Please refer to Confidential Attachment Sierra Club 1.3 1st Supplemental.

(c) Please refer to Confidential Attachment Sierra Club 1.3 1st Supplemental.

(d) Please refer to Confidential Attachment Sierra Club 1.3 1st Supplemental.

(e) Please refer to Confidential Attachment Sierra Club 1.3 1st Supplemental.

(f) There are no variable operation and maintenance (O&M) costs reported for non-fuel, as these costs were included in fixed O&M. Please refer to Confidential Attachment Sierra Club 1.3 1st Supplemental.

(g) Fuel costs for PaR are input in the model and considered tiered pricing in developing the expected fuel prices in cents per million British thermal units. Dollars per megawatt-hour data is not available.

(h) Please refer to Confidential Attachment Sierra Club 1.3 1st Supplemental.

(i) Please refer to Confidential Attachment Sierra Club 1.3 1st Supplemental which provides fixed mine recovery costs, Jim Bridger mine reclamation, and coal liquidated damages.

(j) The purpose of the IRP is to determine the least-cost, least-risk resource portfolio. Tiered fuel costs were developed for use in the IRP's PaR model. Fuel was split between the variable cash costs and fixed cost that included mine capital recovery, reclamation at Jim Bridger, and coal liquidated damages. Un-recovered mine cost balance at December 31, 2018, was not included in the PaR analysis as these costs were already incurred. The PaR model commits thermal units to meet load and reserve requirements, and sells into the market when there is available energy to lower system cost. The PaR dispatch considers heat rates, ramping, minimum up and down times. The PaR model dispatches using average prices as opposed to marginal prices. The purpose of the TAM is to forecast net power costs (NPC) per an economic dispatch of the existing resources for the next calendar year. For a description of the assumptions used in NPC, please refer to the company's response to Sierra Club Data Request 1.4.

The Confidential Attachment is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

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April 24, 2020
Sierra Club Data Request 1.4

Sierra Club Data Request 1.4

With respect to the dispatch and accounting or costing tiers of the Company's coal fuel units in NPC:

(a) Please explain the use of different dispatch or costing cost tiers in GRID and what each represents.

(b) Please explain and provide a numeric example for how the dispatch and costing tiers are related to the total unit price of coal for a fixed price or take-or-pay fuel contract.

(c) Please explain and provide a numeric example for how the dispatch and costing tiers are related to the total unit price of coal for a fuel contract with liquidated damages (i.e. damages less than the total cost of fuel).

(d) Please explain and provide a numeric example for how the dispatch tier and costing tiers are related to the total unit price of coal for a fuel contract with no fixed terms or liquidated damages.

Response to Sierra Club Data Request 1.4

(a) The Generation and Regulation Initiative Decision Tool (GRID) utilizes two different price tiers in the modeling of the company's thermal plants; the (1) "dispatch tier," and the (2) "costing tier."

(1) The "dispatch tier" costs are the incremental costs to operate PacifiCorp's coal plants. The incremental cost is the change in cost to generate additional generation from each power plant. The incremental costs include the cost to purchase additional fuel, the incremental heat rate (efficiency) to operate the plant, and the variable operations and maintenance expense. GRID dispatches individual resources on a marginal or incremental cost basis, to optimize the dispatch of the company's existing system in the most economic manner while accounting for system constraints.

(2) The "costing tier" is the average annual unit price for fuel expense. The average cost of coal includes all of the cost of coal purchased under existing coal supply agreements or from company mining operations. GRID uses the costing tier price multiplied by the coal volumes to arrive at the total coal fuel expense.

(b) The take-or-pay provisions in PacifiCorp's coal supply agreements (CSA) require the payment for the coal even if it is not delivered or used for generation, therefore the fuel portion of the marginal cost of generation in that price tier is zero. The company does not use the average price as a dispatch price in short-term forecasts because the cost of coal in a take-or-pay volume tier is not avoidable.

For example, suppose a CSA had a provision with a minimum take-or-pay volume of 1,000,000 tons. The incremental price for volumes between zero and 1,000,000 tons would be zero because the take-or-pay volumes are treated as a minimum requirement or sunk cost. Suppose further that the CSA set a price for the first 1,000,000 tons at $2 per million British thermal units ($/MMBtu) and any purchases above 1,000,000 tons were $1/MMBtu. The incremental price above the take-or-pay volume of 1,000,000 tons would be $1/MMBtu. Assume that GRID modeled generation of, and the company purchased 2,000,000 tons, the average or "costing tier" price in GRID would be $1.50/MMBtu, and the incremental or "dispatch tier" price would be $1/MMBtu.

(c) Liquidated damages provisions provide for a payment, less than the full price of coal, to be due if PacifiCorp fails to take the minimum contract volume. The company accounts for liquidated damages in its dispatch analysis by recognizing that these costs will be incurred if the units are not dispatched at a level that consumes coal above the contractual minimums.

For example, suppose the same CSA example in subpart (b) above had a liquidated damages provision in conjunction with the minimum volume of 1,000,000 tons. Therefore, instead of the company having a full take-or-pay provision and being obligated to pay $2/MMBtu for any shortfall of volumes below 1,000,000 tons, the liquidated damages provision called for a payment of $0.25/MMBtu for any shortfall. Therefore, the "dispatch tier" price would be $1.75/MMBtu for volumes between zero tons and 1,000,000 tons. The dispatch tier for volumes over 1,000,000 tons would be $1.00/MMBtu. If the company purchased 2,000,000 tons, the "costing tier" price would remain at $1.50/MMBtu.

(d) Suppose the CSA from the example in subpart (b) above did not have a minimum take-or-pay volume or liquidated damages provision. Suppose further that GRID modeled and the company purchased 2,000,000 tons. The average or "costing tier" price in GRID would be $1.50/MMBtu and the incremental or "dispatch tier" price would be $1/MMBtu. There are no CSAs included in the transition adjustment mechanism that fall into this category.

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Sierra Club Data Request 1.10

Sierra Club Data Request 1.10

Regarding the Company's unit commitment decision process for its coal-fuel units:

(a) Identify all the inputs from specific generators that are used to:
i. Calculate offers into EIM.
ii. Determine hourly dispatch decisions.
iii. Model hourly dispatch in GRID for the purposes of forecasting NPC.

(b) Identify all the inputs that are not specific to generators that are used to:
i. Calculate offers into EIM.
ii. Determine actual hourly dispatch decisions.
iii. Model hourly dispatch in GRID for the purposes of forecasting NPC.

(c) Please explain whether the fuel costs included in each of (i)-(iii) below include all components of the cost for fuel purchased through a multi-year contract:
i. The hourly bids submitted to the Western EIM.
ii. The determination of economic hourly dispatch decisions.
iii. The GRID modeling for the purposes of forecasting NPC.

(d) Please explain whether there is any portion of the fuel purchased through a multiyear contract that is ever excluded from the fuel cost component of:
i. The hourly bid prices to the Western EIM.
ii. The hourly dispatch decisions.
iii. The cost inputs to the GRID model for the purposes of forecasting NPC.

For each of the (a)-(d), (i)-(ii), produce all inputs for the last two full calendar years.

For each of the (a)-(d), (iii), produce all inputs for the forecast calendar year 2021.

Response to Sierra Club Data Request 1.10

(a) Please refer to the Company's responses to subparts i. through iii. below:

i. Please refer to the Company's response to Sierra Club Data Request 1.8, and Confidential Attachment Sierra Club 1.10-1. Referencing Sierra Club Data Request 1.8, inputs specific to generators are "iFuel," "iHR," and "vO&M."

ii. The Company co-optimally economically dispatches the entire fleet of resources to satisfy energy requirements and operational constraints set forth by the North American Electric Reliability Corporation.

iii. For the coal unit thermal attributes, please refer to Confidential Attachment Sierra Club 1.10-2. For coal fuel prices used in Generation and Regulation Initiative Decision Tool (GRID), please refer to the 5-day confidential work paper supporting the direct testimony of David G. Webb, specifically file "ORTAM21_Fuel Price (1912) CONF.xlsm."

(b) Please refer to the Company's responses to subparts i. through iii. below:

i. Please refer to the Company's response to Sierra Club Data Request 1.8, and Confidential Attachment Sierra Club 1.10-1. Referencing Sierra Club Data Request 1.8, the input that is not specific to generators is "GMC."

ii. Everything that would affect the aggregate demand for electricity.

iii. Please refer to the company's response to Sierra Club Data Request 1.9 subpart (g). All GRID inputs affect system dispatch.

(c) Please refer to the Company's responses to subparts i. through iii. below:

i. The fuel costs included in the Energy Imbalance Market (EIM) bids for all thermal generation resources are the incremental fuel costs as referenced in the Company's response to Sierra Club Data Request 1.8. To the extent that there exists non-incremental components of fuel costs for a generation resource, this component is not a part of the EIM bid.

ii. The use of the phrase "all" (always / never / 100 percent) disqualifies the premise of the statement from being true.

iii. Please refer to the Company's response to Sierra Club Data Request 1.4.

(d) Please refer to the Company's responses to subparts i. through iii. below:

i. The fuel costs included in EIM bids for all thermal generation resources are the incremental fuel costs as referenced in the Company's response to Sierra Club Data Request 1.8. To the extent that there exists non-incremental components of fuel costs for a generation resource, this component is not a part of the EIM bid.

ii. The average price of fuel is not used in hourly dispatch decisions.

iii. Please refer to the company's response to Sierra Club Data Request 1.4.

The Confidential Attachments are designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

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Sierra Club Data Request 1.24

Please refer to page 17 and 18 of Mr. Webb's direct testimony:

(a) Please explain economic cycling.

(b) Please explain why economic cycling was limited to Hunter Units 1&2.

(c) Please explain why economic cycling was limited to the period February-May.

(d) Please explain whether the Company has conducted GRID modeling runs in which economic cycling applied to a larger subset or all coal units.

i. If not, please explain why.
ii. If yes, please provide all relevant work papers.

Response to Sierra Club Data Request 1.24

(a) Economic cycling is a modeling setup used in the Generation and Regulation Initiative Decision Tool (GRID) which allows GRID to model economic shutdowns for coal plants that are majority-owned by the company, that are not participating in the Western Energy Imbalance Market (EIM), and that are not under operational constraints that would preclude an economic shutdown.

(b) Hunter Unit 1 and Hunter Unit 2 do not participate in the EIM.

(c) The cycling period (i.e., when a coal unit could be shut down for economic reasons) runs from February 1 to May 31, which corresponds to the spring run-off period when loads are generally lower, weather is typically mild, market prices are lower, and solar imports from California are increasing.

(d) No. Please refer to the Company's response to subpart (a) above.

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Sierra Club Data Request 1.29

Please refer to pages 3 and 8 of Mr. Ralston's testimony. Mr. Ralston states that "*Bridger Coal Company coal deliveries can be flexed down to satisfy the Jim Bridger plant's requirements, as necessary*". He also states that "Bridger Coal Company delivered fewer base tons due to a reduction in coal consumption requirements at the Jim Bridger plant. This increased coal costs".

(a) Please confirm that there is no minimum take requirement from the Bridger Coal Company.

(b) Please explain why the reduction in coal consumption requirements led to an increase in coal costs.

(c) Please reconcile the statement about the ability to flex down coal deliveries from the Bridger Coal Company with the increased cost as a result of the reduction.

(d) Please explain how this tradeoff compares to a theoretical minimum take requirement.

(e) Please explain the pricing structure in the unit's contract with the Bridger Coal Company and how this structure results to the cost increase.

Response to Sierra Club Data Request 1.29

(a) Bridger Coal Company (BCC) production volumes are adjusted to meet Jim Bridger plant coal consumption requirements. Therefore, no minimum take tonnage shortfall payments are assessed by BCC.

(b) BCC operating costs include fixed costs that do not correlate with annual changes in coal production. As coal consumption at the Jim Bridger plant decreased, BCC is projected to deliver fewer tons. Simply stated, when the numerator (fixed costs) does not change and the denominator (tons) decreases, costs expressed on a per ton basis increase

(c) In the direct testimony of Dana M. Ralston, the statement regarding BCC's ability to "flex down" coal deliveries did not imply a reduction in tons delivered could be achieved at a zero cost impact to customers. Rather, it implies BCC is able to minimize the unfavorable cost impact of delivering fewer tons by making operational changes such as transitioning from a focus on coal production to a focus on coal production and final reclamation.

(d) The Company has stated in its response to subpart (a) above that BCC does not assess contract minimum or shortfall payments at BCC.

(e) PacifiCorp objects to this request as vague, ambiguous, and not reasonably calculated to lead to admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

Please refer to the Company's responses to subparts (a) and (b) above for description of why costs could increase at BCC.

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Sierra Club Data Request 1.31

Sierra Club Data Request 1.31

Identify all currently effective coal supply contracts that include a provision that allows PacifiCorp to reduce any minimum purchase obligation for coal based on actual or prospective environmental legislation or regulation impacting coal-burning generation:

(a) For each such identified provision, identify the minimum purchase obligation that would result if PacifiCorp elected to use or rely on such provision.

(b) For any currently effective coal supply contract, has PacifiCorp elected to use or rely on a provision that allows PacifiCorp to reduce the minimum purchase obligation for coal based on actual or prospective environmental legislation or regulation impacting coal-burning generation? If yes, identify the specific contract and date of such election.

(c) Please provide any and all analysis conducted on relying on such a provision in each of PacifiCorp's coal supply contracts. If no such analysis has been conducted, please explain why.

Confidential Response to Sierra Club Data Request 1.31

The currently effective coal supply agreements (CSA) are listed below:

I. Naughton Plant CSA– PacifiCorp & Kemmerer Operations, LLC

Article 3.1 <u>Environmental Response</u>

II. Huntington Plant CSA– PacifiCorp & Wolverine Fuels, LLC

Article VIII <u>Environmental Regulations</u>

III. Hunter Plant CSA – PacifiCorp & Wolverine Fuels, LLC

19.4 <u>Impact of Environmental Protections</u>

IV. Colstrip Plant CSA – PacifiCorp & Westmoreland Rosebud Mining, LLC

Article 8.1 <u>Changes in Applicable Law</u>

(a) Please refer to the company's response below, referencing items I through IV above:

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I. Naughton Plant CSA – **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** tons per year.

II. Huntington Plant CSA – **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** after an interim period and under certain conditions in the agreement.

III. Hunter Plant CSA – **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** under certain conditions in the agreement.

IV. Colstrip Plant CSA – **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** under certain conditions in the agreement.

(b) Yes –PacifiCorp ceased burning coal at Naughton Unit 3 on January 30, 2019 in compliance with the requirements of the Wyoming Regional Haze state implementation plan. To accommodate that environmental compliance requirement, on March 12, 2015, PacifiCorp exercised the provision contained in the Naughton Plant CSA that allowed it to reduce the minimum purchase obligation for coal. This action reduced the minimum volume requirement from **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** per year to **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

(c) Please refer to the Company's response to Sierra Club Data Request 1.30 subpart (b).

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

UE 375/PacifiCorp
May 12, 2020
Sierra Club Data Request 3.5

Sierra Club Data Request 3.5

Please refer to the "PacifiCorp Confidential Long-Term Fuel Supply plan for the Jim Bridger Plant". On page 3, it is stated that "To develop the 2018 Fuel Plan, PacifiCorp has studied, reviewed and evaluated different fueling options for the Jim Bridger plant. For the 2018 Fuel Plan, the annual generation requirements expressed in consumed tons were derived from PacifiCorp's budget which is calculated using PacifiCorp's Generation and Regulation Initiative Decision Tools (GRID) model". A footnote is also included mentioning that "The GRID model used for budget purposes is different than the GRID model used in the Oregon TAM. The budget GRID model is used to determine the net power cost budget but is not subject to the same normalizing and regulatory modeling constraints as the GRID model used in the Oregon TAM."

(a) Please identify and explain the "normalizing and regulatory modeling constraints".

(b) Please explain all differences in the GRID model structure between the two use cases (PacifiCorp's budget and TAM).

(c) Please explain all differences in the GRID inputs between the two use cases.

(d) Please provide the "annual generation requirements expressed in consumed tons" from PacifiCorp's budget for all coal units from 2018 until the latest year that the analysis has been done and for all years that the analysis covers.

(e) Please explain whether the "annual generation requirements" from PacifiCorp's budget will serve as the basis for the evaluation of fueling options including the minimum take provisions in a CSA for the Hunter and Dave Johnston units, or whether the generation as forecasted in TAM will serve as the basis for such negotiations. If neither, please explain.

(f) Please explain whether the generation requirements derived from PacifiCorp's budget include projections for several or a single year.

(g) Please explain whether the GRID model as used in PacifiCorp's budget:

i. includes must-run constraints;

ii. includes minimum fuel consumption constraints (as the one specified in SC 1-30 for Naughton); and

iii. dispatches units based on the incremental fuel cost and if so, how the incremental cost is defined.

UE 375/PacifiCorp
May 12, 2020
Sierra Club Data Request 3.5

Response to Sierra Club Data Request 3.5

PacifiCorp objects to this request as outside the scope of this proceeding and not reasonably calculated to lead to admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

PacifiCorp clarifies that the Generation and Regulation Initiative Decision Tool (GRID) is one software model which the Company utilizes for different purposes. The difference between regulatory purposes and business planning purposes is that GRID uses different databases with different inputs and assumptions. Based on this clarification, the Company responds as follows:

(a) The "normalizing and regulatory modeling constraints" refers to certain model inputs and assumptions the Company uses to develop the Oregon transition adjustment mechanism (TAM) net power costs (NPC) using GRID. These "normalizing and regulatory modeling constraints" are described in the TAM guidelines originally adopted in Order No. 09-374 and modified by subsequent TAM orders.

(b) The GRID model used for budgetary purposes and regulatory purposes is the same, however, the underlying database is different.

(c) PacifiCorp objects to this request as overbroad and vague and not reasonably calculated to lead to discoverable evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

It is unclear to PacifiCorp which individual use cases that Sierra Club is referring to. However, as described in part (a) of this response, the GRID Inputs for the TAM are specified in the TAM guidelines.

(d) PacifiCorp objects to this request as it asks for information beyond the scope of this proceeding and the relevant test period of calendar year 2021. Without waiving the foregoing objection, the Company responds as follows:

The annual generation forecast expressed in consumed tons from PacifiCorp's budget for all coal units from 2018 for the period of 2019-2028 and from 2019 for the period of 2020-2029 is considered highly confidential and commercially sensitive. The Company requests special handling. Please contact Ajay Kumar at (503) 813-5161 to make arrangements for review.

(e) PacifiCorp considers different aspects of the coal market opportunities / limitations that are present to each plant when developing minimum take provisions for a particular coal supply agreement. An analysis will be performed at the time of negotiations for new coal supply agreements based on then current market conditions rather than historic business plan forecasts or TAM forecasts.

(f) PacifiCorp's budget is a 10-year forecast.

(g) Please refer to the Company's responses to i. through iii. below:

i. In GRID used for budget purposes, coal plants do not include must run constraints, but are subject to out of model adjustments to ensure that, at least in the near term, contractual minimum purchases are satisfied.

ii. In GRID used for budget purposes, the minimum fuel consumption constraints are applied to the following coal plants with take-or-pay coal supply contracts – Jim Bridger, Hunter, Huntington, Naughton, Dave Johnston, Hayden, Colstrip and Wyodak.

iii. In GRID used for budget purposes, coal plants are dispatched using incremental fuel costs. The incremental coal costs are provided from the fuel resources management team.

UE 375/PacifiCorp
May 12, 2020
Sierra Club Data Request 3.11

Sierra Club Data Request 3.11

Please refer to PacifiCorp's response to SC 1-30(c) which states that "the minimum contractual obligation or requirement of [redacted] tons is used as a minimum." Please explain whether such minimum generation constraint applies to any other unit. If yes, please provide the minimum generation level for all units.

Response to Sierra Club Data Request 3.11

Yes there are minimum contractual obligations as part of the coal supply agreements at other plants. For the minimum contractual obligations for each coal plant, please refer to the Company's response to Sierra Club Data Request 3.3, specifically Confidential Attachment Sierra Club 3.3.

OPUC Data Request 06

For any shutdown detailed in the Company's response to DR 5 section "a", which the Company believes to be an isolated instance and not comparable to a shutdown of a plant for economic reasons:

(a) Please provide a detailed explanation of the circumstances of the referenced shutdown.

(b) Please provide a detailed explanation of why the Company believes that this shutdown is not comparable to a shutdown of a plant for economic reasons.

(c) Please provide the Company's definition of the following terms, clearly indicating the differences between each.

i. Shutdown.
ii. Reserve shutdown.
iii. Outage.
iv. Economic cycling.

Response to OPUC Data Request 06

(a) Please refer to the Company's response to OPUC Data Request 05, specifically Confidential Attachment OPUC 05. Any events listed with a "Yes" in column A "Does shutdown follow or precede other outage? Ie., Forced, maint, etc?" are not considered to be a shutdown for an economic reason. These instances are short extensions (a few hours to a few days) of maintenance-related outages and are not the same as a shutdown of a plant for economic reasons that typically lasts for a week or more. The Company periodically extends outages for several hours or days for various operational reasons, including if there is no immediate need to bring the unit back online when the outage is over. Extending an outage for several additional hours or days should not be included in the analysis of actual economic cycling.

(b) Please refer to the Company's response to subpart (a) above.

(c) Please refer to the Company's responses to subparts (i) through (iv) below:

i. Shutdown is a non-specific term that could be reasonably used any time a unit is taken offline.

ii. A reserve shutdown is offline time not considered an "outage" by the North American Electricity Reliability Corporation (NERC). They are typically the result of an operational decision based on market conditions, load requirement, and resource availability during the shut-down period. This term can be applied to a shutdown for economics, or for non-economic, and non-maintenance reasons (e.g. transmission derates, pipeline restrictions, etc.).

iii. Outages typically fall into two categories – maintenance outages and planned outages. A planned outage is an outage that is scheduled well in advance and is of a predetermined duration, lasts for several weeks, and occurs only once or twice a year. Turbine and boiler overhauls or inspections, testing, and nuclear refueling are typical planned outages. A maintenance outage is an outage that can be deferred beyond the end of the next weekend (Sunday at 2400 hours), but requires that the unit be removed from service, another outage state, or reserve shut-down state before the next planned outage.

iv. Economic cycling is the act of temporarily reducing a unit's output to zero because it is the cost-minimizing option, as opposed to doing so in order for maintenance work to be performed or because of system restrictions. It may reasonably be considered a subtype of reserve shutdown, but only when the reserve shutdown is driven by economic considerations.

UE 375/PacifiCorp
April 3, 2020
OPUC Data Request 08

OPUC Data Request 08

If PacifiCorp has analyzed the potential benefits of extending the cycling period, please provide a narrative explanation of the results and a copy of this analysis in electronic spreadsheet format, with all formulas and cell references intact.

Response to OPUC Data Request 08

The Company has not performed the analysis. The cycling period used in the transition adjustment mechanism (TAM) is informed by the historical data as to when coal units have been economically cycled in the past. Historically, economic cycling of coal units has occurred in the spring because of reduced loads and hydro and solar conditions. When determining whether to cycle a coal unit for economic purposes, system reliability must also be considered.

UE 375/PacifiCorp
April 3, 2020
OPUC Data Request 09

OPUC Data Request 09

If PacifiCorp has carried out analysis comparing the benefits of a unit participating in EIM to the unit economic cycling, please provide a narrative explanation of the results and a copy of this analysis in electronic spreadsheet format, with all formulas and cell references intact.

Response to OPUC Data Request 09

The Company has not performed the analysis. The cycling period used in the transition adjustment mechanism (TAM) is informed by the historical data as to which coal units have been economically cycled in the past. Historically, coal units that participate in the energy imbalance market (EIM) generally have not been cycled off for economic purposes. Because EIM participating coal units can provide benefits to customers because of their flexibility in the EIM, non-participating coal units are typically chosen for economic cycling before EIM participating coal units. When determining whether to cycle a coal unit for economic purposes, system reliability must also be considered.

UE 375/PacifiCorp
April 2, 2020
OPUC Data Request 11

OPUC Data Request 11

If PacifiCorp has discussed the possibility of economic cycling with the co-owners of its minority-owned units, please provide copies of all communications, and a narrative summary of the results.

Response to OPUC Data Request 11

The Company has briefly discussed this at some of the plants, but due to differing system load and market dynamics no agreement on shutdowns was possible. There is no documentation.

UE 375/PacifiCorp
April 21, 2020
OPUC Data Request 53

OPUC Data Request 53

Has the Company begun the process of soliciting bids for the 2021 open position of the Dave Johnston plant? If so, please provide an update on the status of these negotiations. If no, when does the Company expect to begin this process?

Response to OPUC Data Request 53

No, the Company expects the request for proposals process to commence in the second or third quarter of 2020.

UE 375/PacifiCorp
April 21, 2020
OPUC Data Request 55

OPUC Data Request 55

Please refer to PAC/300, Ralston/14.

(a) Please explain whether the pricing for coal costs for the Hunter plant in the 2021 is based on future market prices or the estimated price for the new coal supply agreement in 2021.

(b) Is the Company currently in negotiations for a new coal supply agreement for the Hunter plant?

Response to OPUC Data Request 55

(a) The pricing for the coal costs for the Hunter plant for 2021 is based upon the estimated price for the new coal supply agreement (CSA). This estimate uses future market prices for its calculation.

(b) Yes, PacifiCorp is currently in negotiations for a new CSA for the Hunter plant.

UE 375/PacifiCorp
May 7, 2020
OPUC Data Request 107

OPUC Data Request 107

Economic Cycling
The Company's response to DR 12 states "the Company proposes modeling economic shutdowns for coal plants that are … not under operational constraints that would preclude an economic shutdown:"

(a) Please provide a list of the operational constraints that would preclude an economic shutdown.

(b) Please indicate which of the Company's generator units the Company considers to be under operational constraints that would preclude an economic shutdown.

(c) For each generator identified in the Company's response to section "b", please provide a narrative explanation of the operational constraints that would preclude an economic shutdown.

Response to OPUC Data Request 107

The operational constraints referenced in the Company's response to OPUC Data Request 12 subpart (a) are not a finite list of itemized possibilities. If the Generation and Regulation Initiative Decision Tool (GRID) requires a unit in order to reach a least-cost solution that satisfies all system requirements and obeys all system constraints, then the unit in question can be said to face an operational constraint that prevents economic cycling. This is referred to as operational in nature because the availability of other units, the status of the transmission grid, system load levels, and other operational inputs can change unit commitment decisions in the GRID forecast. Currently, the Company forecasts economic cycling at Hunter Unit 1 and Hunter Unit 2 in the test period for the 2021 Transitional Adjustment Mechanism. These two units are forecasted to be offline for economics from February 4, 2021 to May 31, 2021 and March 10, 2021 to May 31, 2021, respectively.

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

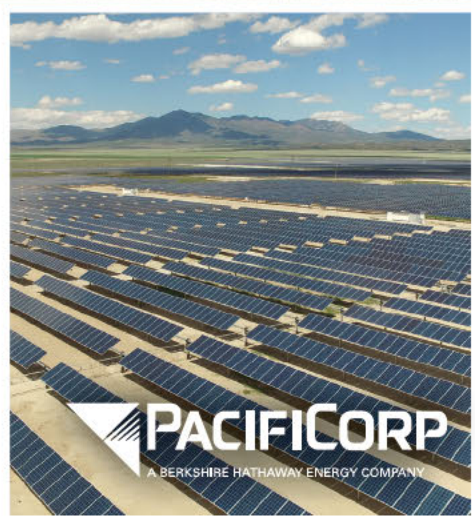
SIERRA CLUB EXHIBIT 106

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp 2019 Integrated Resource Plan (excerpt)

2019 Integrated resource plan

VOLUME II – APPENDICES M-R
OCTOBER 18, 2019



This 2019 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

For more information, contact:
PacifiCorp
IRP Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
irp@pacificorp.com
www.pacificorp.com

Cover Photos (Top to Bottom):
Marengo Wind Project
Transmission Line
Electric Meter
Pavant III Solar Plant

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APPENDIX R –COAL STUDIES

Introduction

The 2019 Integrated Resource Plan (IRP) includes a thorough and robust economic analysis of PacifiCorp's coal units. The coal study analysis conducted in the 2019 IRP was initially prompted by the Public Utility Commission of Oregon (OPUC) in its 2017 IRP acknowledgement order, which administratively established certain study parameters that defined the scope and breadth of the analysis. PacifiCorp met these requirements and then developed a more complete study to ensure that it adequately captured the costs to maintain system reliability. The coal study analyses that informed the 2019 IRP portfolio-development process were completed in three phases:

- Phase One
  Unit-by-unit early retirement studies, which focused on impacts to resource portfolio selections and system costs from the System Optimizer (SO) model, were developed. Each unit-specific early retirement scenario assumes closure at the end of 2022. This phase met requirements set forth by the OPUC 2017 IRP acknowledgement order (Order No. 18-138), and concluded with the June 28-29, 2018 2019 IRP public-input meeting and compliance filing to the OPUC in Docket No. LC-70 on June 29, 2018.

- Phase Two
  A series of studies were produced that expanded the scope of the phase one studies. The expanded scope included an evaluation of unit-by-unity early retirement scenarios using the Planning and Risk model (PaR), stacked retirement scenarios, where multiple early closures were evaluated in a single scenario, and alternative year scenarios, which considered changes in the timing of assumed early closure dates for certain coal units. At this point in the process, PacifiCorp had identified capacity shortfalls in the early retirement scenarios that would compromise system reliability if not remedied. The second phase concluded with the December 2018 coal analysis presented to stakeholders at the December 3-4, 2018 public-input meeting, where PacifiCorp communicated to its stakeholders that additional analysis would need to be developed to address the capacity shortfalls identified in the phase two results.

- Phase Three
  Additional analysis was performed on the stacked retirement scenarios evaluated in phase two of the coal study analyses. The third phase concluded with the April 2019 coal analysis, presented to stakeholders at the April 25, 2019 public-input meeting.

Each of the coal study phases show that early retirement of certain coal units has potential to reduce overall system costs. In particular, the coal studies showed that the greatest customer benefits were most likely to be realized with potential early retirement of coal units at the Naughton and Jim Bridger coal plants located in Wyoming.

This appendix describes the methodology and approach taken in each of the three phases of the coal studies and reports modeling and performance evaluation results. Aligning with expectations communicated to stakeholders at public-input meetings held as the 2019 IRP was being developed, the outcomes of the coal studies were used to inform the 2019 IRP portfolio-development process, which is described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

Phase One: Unit-by-Unit Coal Studies

In its 2017 IRP acknowledgement order (Order No. 18-138), the OPUC established requirements for a unit-by-unit series of coal retirement studies, which were to be completed by June 30, 2018. The requirements set forth in Order No. 18-138 are as follows:

- PacifiCorp agrees to perform 25 SO model runs, one for each coal unit and a base case.
- PacifiCorp agrees to summarize results and provide:
    - A table of the difference in present-value revenue requirement (PVRR) resulting from the early retirement of each unit;
    - An itemized list of coal unit retirement cost assumptions used in each SO model run; and
    - A list of coal units that would free up transmission along the path from the proposed Wyoming wind projects if retired.

These requirements are consistent with OPUC staff data request 65, which was submitted to PacifiCorp during the 2017 IRP acknowledgement proceeding. In this data request, OPUC staff provided additional guidance that established expectations for the scope of the unit-by-unit coal study analysis described in OPUC Order No 18-138. The specific guidance provided in OPUC staff data request 65 include:

- PacifiCorp should assume a December 2022 retirement date for each early retirement run.
- PacifiCorp should assume Reference Case Regional Haze assumptions (from the 2017 IRP) that are modified to exclude incremental selective catalytic reduction (SCR) costs for Jim Bridger, Hunter, and Huntington in the benchmark case.
- In agreeing to perform this analysis, PacifiCorp cautioned that:
    - The studies would not provide a complete, portfolio-level view of the economics of PacifiCorp's coal portfolio;
    - The structure of the analysis requested by OPUC staff would not capture the system-cost impact that would result from retiring more than one coal unit; and
    - Results from these studies would therefore provide limited insight into a least-cost, least-risk resource portfolio.

Recognizing PacifiCorp's concerns outlined above, the Utah Public Service Commission in its 2017 IRP acknowledgment order in Docket No. 17-035-16 states "we find that additional analysis will be helpful only if it supplements, rather than replaces, the type of coal plant modeling PacifiCorp utilized for its 2017 IRP."

Unit-by-Unit Study Methodology

To meet the requirements set forth in OPUC Order No. 18-138, PacifiCorp developed a portfolio optimization for each coal unit using the SO model, and compared those model results to a benchmark case that assumed continued operation of coal units through their depreciable life, which for certain units, extends beyond the life assumed in the 2017 IRP preferred portfolio.[1] Consequently, in this context, the benchmark case developed for the coal studies is not intended to represent PacifiCorp's default plan. Rather, the benchmark case developed for the coal studies is only intended to serve as a point of comparison for the unit-by-unit retirement scenarios. Table R.1 summarizes the steps that were followed to produce the unit-by-unit analysis.

Table R.1 – Summary of Unit-by-Unit Methodology Steps

Step	Measure	Description
A	2017-2036 System PVRR (x1)	Base Case (One SO Model Run) • 2017 IRP Update with following modifications • Removal of 161 MW Uinta Wind Project (2021-2036) • 2017 IRP Reference Case Regional Haze assumptions • March 2018 official forward price curve with medium CO_2 price inputs • Results are calculated with and without incremental selective catalytic reduction costs for Jim Bridger 1 and 2
B	2017-2036 System PVRR (x22)	Retirement Cases (22 SO Model Runs) • 2017 IRP Update with following modifications • Removal of 161 MW Uinta Wind Project (2021-2036) • 2017 IRP Reference Case Regional Haze assumptions • March 2018 official forward price curve with medium CO_2 price inputs • No incremental selective catalytic reduction costs • Each run assumes the retirement of a single coal unit at the end of 2022
C	2017-2036 System PVRR(d) (x22)	Present-Value Revenue Requirement Differential (PVRR(d)) • Change in system PVRR between the Base Case (A) and each of 22 Retirement Cases (B)

- High-level estimates of transmission reinforcement costs are applied as an adder to the results from step C.
- Each SO model run reflects unique coal-unit operating cost assumptions consistent with assumed retirement dates (*i.e.*, fuel cost, run-rate operating costs, and decommissioning costs).
- PacifiCorp did not perform SO model runs in step B for Naughton Unit 3 and Cholla Unit 4, which are already assumed to retire before 2022.

Unit-by-Unit Study Results

Table R.2 lists the coal units studied in the unit-by-unit analysis, including each unit's relative ranking of potential customer benefits from a potential early closure based on the SO model optimized portfolio results. Units with the lowest numeric rankings (starting with 1) reported the greatest potential for customer benefits from early retirement. Relative to the Reference Case from the 2017 IRP, the SO model reported lower system costs with an assumed 2022 early retirement date for eight of the 22 units studied (39 percent on a capacity basis). The units with the greatest potential for customer benefits from early retirement on a unit-by-unit basis were Jim Bridger Unit 1, Jim Bridger Unit 2, Naughton Unit 1, and Naughton Unit 2, followed by Hayden Unit 1, Hayden Unit 2, Hunter Unit 1, and Craig Unit 2.

[1] For instance, the 2017 IRP preferred portfolio assumed Jim Bridger Unit 1 would retire at the end of 2028 and Jim Bridger Unit 2 would retire at the end of 2032. The coal study benchmark case assumes that these units continue to operate through 2037.

Table R.2 – Unit-by-Unit Coal Study Results Ranked by Potential Customer Benefits

Coal Unit	PacifiCorp Share Capacity (MW)	PacifiCorp Percentage Share (%)	State	Ranking (High to Low Potential Customer Benefits)
Colstrip 3	74	10	MT	17
Colstrip 4	74	10	MT	16
Craig 1	82	19	CO	11
Craig 2	83	19	CO	9
Dave Johnston 1	106	100	WY	12
Dave Johnston 2	106	100	WY	13
Dave Johnston 3	220	100	WY	14
Dave Johnston 4	330	100	WY	18
Hayden 1	44	24	CO	7
Hayden 2	33	13	CO	8
Hunter 1	418	94	UT	10
Hunter 2	269	60	UT	15
Hunter 3	471	100	UT	20
Huntington 1	459	100	UT	22
Huntington 2	450	100	UT	19
Jim Bridger 1	354	67	WY	1
Jim Bridger 2	359	67	WY	2
Jim Bridger 3	349	67	WY	6
Jim Bridger 4	353	67	WY	5
Naughton 1	156	100	WY	4
Naughton 2	201	100	WY	3
Wyodak	268	80	WY	21

- In the benchmark case, Jim Bridger Unit 1 and Jim Bridger Unit 2 include SCR costs. The installation of SCR equipment would be required to maintain operation of this facility through 2037.
- Cholla Unit 4 and Naughton Unit 3 are not presented because PacifiCorp already assumes that these units will cease operating as a coal fired facility before the end of 2022 and the intent of the unit-by-unit analysis was not to evaluate whether there might be economic savings from operating these units longer.

The unit-by-unit studies completed in phase one of the coal studies have several limitations, described in detail in both the June 29, 2018 compliance filing in OPUC Docket No. LC-70 and as communicated to stakeholders during the June 28-29, 2018 public-input meeting. These limitations include:

- The potential benefits of early retirement for individual units are not additive and system impacts are not linear. The studies did not attempt to capture the impact on system costs if coal unit retirements are stacked (where more than one unit is assumed to retire early).

- The studies did not capture the operational and other system-reliability impacts associated with:
  - Meeting balancing area reserve requirements;
  - Meeting balancing area frequency response requirements;

- Reduced flexibility between balancing areas (*i.e.*, Jim Bridger provides energy and other reliability services in both the east and west balancing areas); and
- Reduced ability to participate in the energy-imbalance market due to a reduction in flexible generation and inability to pass the flex ramp sufficiency test.

- The studies reflect 2017 IRP system planning assumptions and do not capture system planning assumptions that were being updated for the 2019 IRP (*i.e.*, load forecasts, recent resource additions, planning reserve margins, capacity-contribution values, conservation-potential assessment, supply-side resources, *etc.*)

- The studies were limited to SO model analysis and therefore do not analyze scenario-risk and stochastic-risk analysis.

Considering these limitations, PacifiCorp engaged in phase two of the coal studies to advance and improve upon results from phase one. The phase one results helped to prioritize the more detailed analysis that would be prepared in phase two.

Phase Two: Stacked Coal Studies

PacifiCorp presented the results of its stacked study coal analysis at its December 3-4, 2018 public-input meeting. As illustrated below, additional analysis was performed at this stage, including updated unit-by-unit analysis, stacked retirement analysis, and additional analysis to evaluate alternative retirement dates for certain coal units.

All studies in phase two were performed using the most current system planning assumptions under development for the 2019 IRP (*i.e.*, load forecasts, recent resource additions, planning reserve margins, capacity-contribution values, conservation-potential assessment, supply-side resources, *etc.*). Additionally, all studies in phase two reflect enhancements in the form of additional resource options, transmission modeling enhancements, and PaR stochastic analysis. These updates provided significant improvements to the quality of the results used to indicate which units to study further when developing stacked retirement scenarios.

Additional Resource Options

In updating modeling assumptions to align with the 2019 IRP, the updated and expanded coal study analysis developed for this phase included roughly 250 more renewable resource options that were available for selection in the SO model when it develops resource portfolios, inclusive of customer-preference[2] resources, more geographic locations, more resource types (*i.e.*, solar and wind resources combined with storage), and with updated capacity-contribution levels. This enhancement aligns IRP modeling with the growing diversity of potential projects across PacifiCorp's service area.

Transmission Modeling Enhancement

In the September 27-28, 2019 public-input meeting, PacifiCorp discussed an improvement to overcome transmission modeling limitations in the SO model while reasonably maintaining model performance. Historically, the SO model has been unable to endogenously select among transmission upgrade options when developing its optimized, least-cost mix of resources for a given portfolio. Subsequently, transmission upgrade needs and costs had to be manually evaluated and developed outside the SO model. This advancement of endogenous transmission modeling represents a leap forward in the portfolio-optimization process, despite some resulting impacts on run-time performance. Between June and December 2018, endogenous transmission options were developed, tested and adopted in SO modeling along with validation and reporting features.

This enhancement had important implications for improving the quality of the coal study results. The cost or benefit of a unit retirement at a specific time and location may swing significantly in relation to transmission projects and opportunities to develop replacement resources and brownfield locations following a plant retirement. Additional detail regarding the endogenous transmission modeling approach implemented in the 2019 IRP is provided in Volume I, Chapter 6 (Resource Options).

Stochastic Risk Analysis

Once unique resource portfolios were developed by the SO model, additional modeling was performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed using PaR. The stochastic simulation in PaR produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The PaR simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.[3] The Monte Carlo sampling approach is discussed in more detail in Volume I, Chapter 6 (Resource Options).

Updated Unit-by-Unit Summary Results

Updated unit-by-unit studies were developed in phase two incorporating the enhancements described above. The SO model was used to establish a portfolio for each unit retirement case and the resulting portfolios were then run through the PaR model to assess stochastic performance for the following price-policy scenarios (assumptions for the price-policy scenarios are summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach)):

[2] Refer to Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of customer preference resources and modeling.
[3] Front-office transactions, or FOTs, included in resource portfolios developed using the SO model are subject to the Monte Carlo random sampling of wholesale electricity prices in PaR.

- Base/Base: Medium gas price assumption with medium carbon dioxide (CO_2) price assumption
- High/High: High gas price assumption combined with high CO_2 price assumption
- Low/None: Low gas price conditions combined with no CO_2 price assumption

Table R.3 summarizes the unit-by-unit rankings from phase two, calculated on a nominal levelized basis under the each of the different price-policy scenarios. A negative value represents the potential for reduced costs when the unit is assumed to retire early. Conversely, a positive value represents the potential for increased costs when a unit is assumed to retire early. As was the case in phase one, the potential benefits of early retirement for individual units are not additive and system impacts are not linear. The potential benefits of retiring more than one unit would not be the same as adding up the potential benefits from the unit-by-unit results. Moreover, as discussed previously, these results (and the results presented in Tables R.4 through Table R.7) do not account for the costs to remedy capacity shortfalls in any given scenario. The cost to remedy capacity shortfalls as necessary to maintain a reliable system were captured in phase three.

Table R.3 – Unit-by-Unit Update (Benefit)/Cost of Retirement

SO, Base/Base (Nom. Lev. $/kW-year)	PaR, Base/Base (Nom. Lev. $/kW-year)	PaR, High/High (Nom. Lev. $/kW-year)	PaR, Low/None (Nom. Lev. $/kW-year)

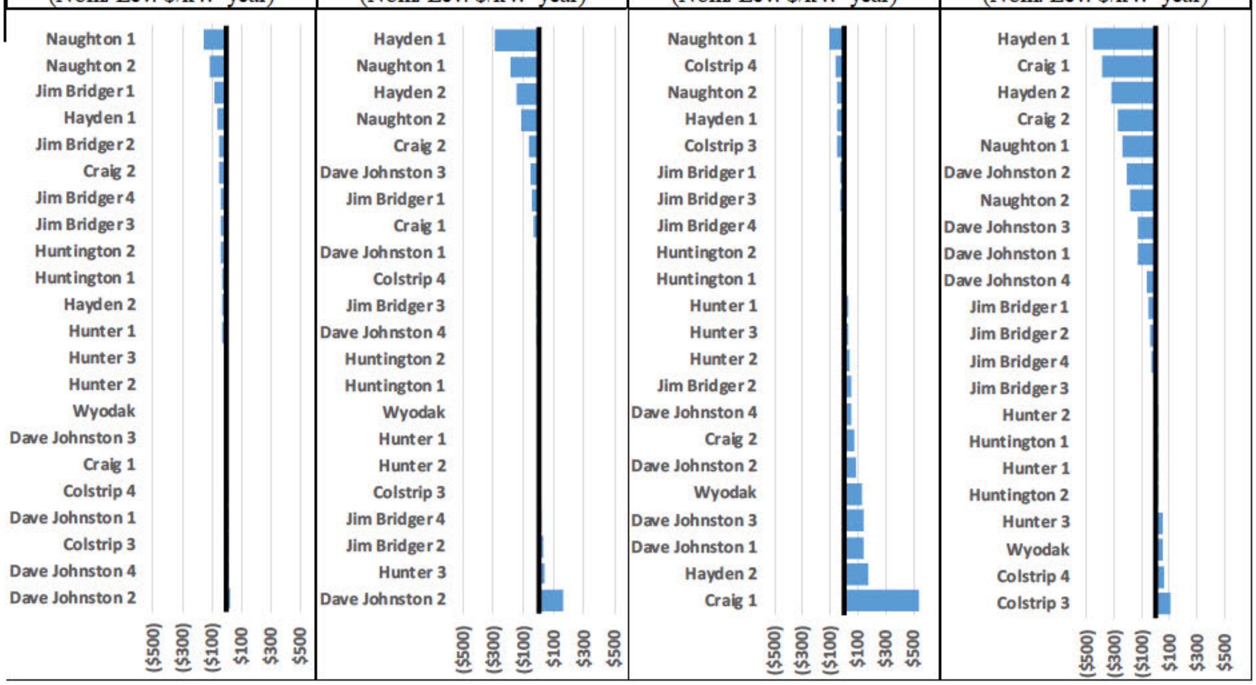


Table R.4 through Table R.7 summarize the unit-by-unit rankings on a present value revenue requirement basis, reporting SO model and PaR results as presented in the December 3-4, 2018 public input meeting.

Table R.4 – SO Model Medium Gas, Medium CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$21,897	n/a
C-02 (Colstrip 3)	$21,906	$9
C-03 (Colstrip 4)	$21,902	$5
C-04 (Craig 1)	$21,897	($0)
C-05 (Craig 2)	$21,875	($22)
C-06 (Dave Johnston 1)	$21,903	$6
C-07 (Dave Johnston 2)	$21,905	$8
C-08 (Dave Johnston 3)	$21,895	($2)
C-09 (Dave Johnston 4)	$21,916	$19
C-10 (Hayden 1)	$21,885	($12)
C-11 (Hayden 2)	$21,893	($4)
C-12 (Hunter 1)	$21,816	($81)
C-13 (Hunter 2)	$21,878	($19)
C-14 (Hunter 3)	$21,853	($44)
C-15 (Huntington 1)	$21,808	($89)
C-16 (Huntington 2)	$21,794	($103)
C-17 (Jim Bridger 1)	$21,690	($207)
C-18 (Jim Bridger 2)	$21,761	($136)
C-19 (Jim Bridger 3)	$21,800	($97)
C-20 (Jim Bridger 4)	$21,797	($100)
C-21 (Naughton 1)	$21,794	($102)
C-22 (Naughton 2)	$21,801	($96)
C-23 (Wyodak)	$21,880	($17)

Table R.5 – PaR Medium Gas, Medium CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$23,310	n/a
C-02 (Colstrip 3)	$23,317	$7
C-03 (Colstrip 4)	$23,302	($8)
C-04 (Craig 1)	$23,304	($6)
C-05 (Craig 2)	$23,281	($29)
C-06 (Dave Johnston 1)	$23,305	($5)
C-07 (Dave Johnston 2)	$23,363	$53
C-08 (Dave Johnston 3)	$23,273	($37)
C-09 (Dave Johnston 4)	$23,304	($6)
C-10 (Hayden 1)	$23,252	($58)
C-11 (Hayden 2)	$23,287	($23)
C-12 (Hunter 1)	$23,341	$31
C-13 (Hunter 2)	$23,334	$24
C-14 (Hunter 3)	$23,438	$128
C-15 (Huntington 1)	$23,326	$17
C-16 (Huntington 2)	$23,310	$0
C-17 (Jim Bridger 1)	$23,197	($113)
C-18 (Jim Bridger 2)	$23,381	$71
C-19 (Jim Bridger 3)	$23,283	($27)
C-20 (Jim Bridger 4)	$23,349	$39
C-21 (Naughton 1)	$23,187	($123)
C-22 (Naughton 2)	$23,212	($98)
C-23 (Wyodak)	$23,323	$13

Table R.6 – PaR High Gas, High CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$28,176	n/a
C-02 (Colstrip 3)	$28,152	($25)
C-03 (Colstrip 4)	$28,145	($31)
C-04 (Craig 1)	$28,265	$89
C-05 (Craig 2)	$28,214	$37
C-06 (Dave Johnston 1)	$28,225	$48
C-07 (Dave Johnston 2)	$28,205	$28
C-08 (Dave Johnston 3)	$28,275	$98
C-09 (Dave Johnston 4)	$28,234	$58
C-10 (Hayden 1)	$28,167	($9)
C-11 (Hayden 2)	$28,203	$26
C-12 (Hunter 1)	$28,258	$81
C-13 (Hunter 2)	$28,255	$79
C-14 (Hunter 3)	$28,297	$121
C-15 (Huntington 1)	$28,215	$38
C-16 (Huntington 2)	$28,172	($4)
C-17 (Jim Bridger 1)	$28,107	($69)
C-18 (Jim Bridger 2)	$28,307	$131
C-19 (Jim Bridger 3)	$28,123	($53)
C-20 (Jim Bridger 4)	$28,156	($20)
C-21 (Naughton 1)	$28,110	($66)
C-22 (Naughton 2)	$28,134	($42)
C-23 (Wyodak)	$28,434	$258

Table R.7 – PaR Low Gas, Zero CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$19,644	n/a
C-02 (Colstrip 3)	$19,701	$57
C-03 (Colstrip 4)	$19,678	$35
C-04 (Craig 1)	$19,579	($64)
C-05 (Craig 2)	$19,513	($131)
C-06 (Dave Johnston 1)	$19,601	($42)
C-07 (Dave Johnston 2)	$19,572	($71)
C-08 (Dave Johnston 3)	$19,554	($89)
C-09 (Dave Johnston 4)	$19,581	($62)
C-10 (Hayden 1)	$19,553	($91)
C-11 (Hayden 2)	$19,596	($48)
C-12 (Hunter 1)	$19,675	$31
C-13 (Hunter 2)	$19,658	$14
C-14 (Hunter 3)	$19,796	$153
C-15 (Huntington 1)	$19,670	$26
C-16 (Huntington 2)	$19,696	$53
C-17 (Jim Bridger 1)	$19,504	($140)
C-18 (Jim Bridger 2)	$19,553	($90)
C-19 (Jim Bridger 3)	$19,642	($2)
C-20 (Jim Bridger 4)	$19,578	($65)
C-21 (Naughton 1)	$19,484	($160)
C-22 (Naughton 2)	$19,488	($156)
C-23 (Wyodak)	$19,746	$103

Alternate Year Unit Analysis

PacifiCorp selected units for further alternate-year analysis based on the unit-by-unit SO model results. Based on the initial SO model results, the following units were selected to test the impacts of delaying individual unit retirements:

- Naughton Unit 1
- Naughton Unit 2
- Jim Bridger Unit 1
- Hayden Unit 1

Table R.8 reports the SO model outcomes of the alternate year studies, and indicates that delaying the retirement of individual units, before accounting for incremental reliability resources needed to remedy capacity shortfalls, in the unit-by-unit studies would reduce potential benefits.

Table R.8 – SO Model Alternate Year Analysis, Medium Gas, Medium CO_2

Study	Alternate Year	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement	Change from 2022 Retirement Assumption
C-01 (Benchmark)	n/a	$21,897	n/a	n/a
C-25 (Naughton 1)	2025	$21,887	($10)	$92
C-26 (Naughton 1)	2028	$21,915	$18	$120
C-27 (Naughton 2)	2025	$21,882	($15)	$81
C-28 (Naughton 2)	2028	$21,915	$18	$114
C-29 (Jim Bridger 1)	2025	$21,756	($141)	$66
C-30 (Jim Bridger 1)	2028	$21,773	($124)	$83
C-31 (Jim Bridger 1)	2031	$21,788	($109)	$99
C-32 (Hayden 1)	2025	$21,884	($13)	($1)
C-33 (Hayden 1)	2028	$21,888	($9)	$3

To confirm this finding, PacifiCorp conducted additional analysis of these studies using PaR. Table R.9 reports results consistent with the SO Model results—before accounting for incremental reliability resources needed to remedy capacity shortfalls, potential benefits for early retirement are greatest with assumed retirement at the end of 2022. Based on results of the alternate-year cases, the stacked-retirement cases developed in phase two of the coal studies assume early retirement of units at the end of 2022.

Table R.9 – PaR Alternate Year Analysis, Medium Gas, Medium CO_2

Study	Alternate Year	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement	Change from 2022 Retirement Assumption
C-01 (Benchmark)	n/a	$23,310	n/a	n/a
C-25 (Naughton 1)	2025	$23,275	($35)	$87
C-26 (Naughton 1)	2028	$23,290	($20)	$103
C-27 (Naughton 2)	2025	$23,277	($33)	$65
C-28 (Naughton 2)	2028	$23,298	($12)	$86
C-29 (Jim Bridger 1)	2025	$23,270	($40)	$73
C-30 (Jim Bridger 1)	2028	$23,262	($48)	$64
C-31 (Jim Bridger 1)	2031	$23,238	($72)	$40
C-32 (Hayden 1)	2025	$23,271	($39)	$20
C-33 (Hayden 1)	2028	$23,277	($33)	$25

Stacked Study Methodology

Based on the outcomes of the updated unit-by-unit analysis, eight stacked-retirement cases were defined to analyze retirement depth for nine coal resources with the highest potential for customer benefits. Table R.10 identifies these cases by name, retired units and the total nameplate of the included retirements.

Each stacked case required the development of a unique set of assumptions, accounting for fuel costs, decommissioning costs, contractual obligations, and the potential loss of existing cost-savings for co-located facilities.

The SO model was used to establish a portfolio for each stacked-retirement case and the resulting portfolios were then run through PaR to assess stochastic performance for the following price-policy scenarios (assumptions for the price-policy scenarios are summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach)):

- Base/Base: Medium gas price assumption with medium CO_2 price assumption
- High/High: High gas price assumption combined with high CO_2 price assumption
- Low/Zero: Low gas price conditions combined with no CO_2 price assumption

Table R.10 – Stacked Retirement Cases

Case Name	2022 Retirements	Nameplate Retired (MW)
C-34	Naughton 1-2 (2022)	357
C-35	Naughton 1-2 (2022) Jim Bridger 1 (2022)	711
C-36	Naughton 1 (2022) Jim Bridger 1 (2022)	510
C-37	Naughton 1 (2022) Jim Bridger 1 (2022) Hayden 1 (2022)	554
C-38	Naughton 1-2 (2022) Hayden 1 (2022) Jim Bridger 1 (2022)	755
C-39	Naughton 1-2 (2022) Hayden 1 (2022) Jim Bridger 1 (2022) Craig 2 (2022)	834
C-40	Naughton 1-2 (2022) Hayden 1 (2022) Jim Bridger 1-2 (2022) Craig 2 (2022)	1,193
C-41	Naughton 1-2 (2022) Jim Bridger 1-2 (2022) Hayden 1-2 (2022) Craig 1-2 (2022) Dave Johnston 3 (2022)	1,529

Stacked Study Results

Table R.11 summarizes the stacked study results under the Base/Base price-policy scenario. Cases C-35, C-38, and C-39 show the largest potential benefits, and the PVRR(d) results for these three cases are very close to one another. Cases C-40 and C-41, both in excess of 1,000 megawatts (MW) of incremental early retirements relative to the benchmark case, show a net cost. As discussed previously, these results (and the results presented in Table R.12 and Table R.13) do not account for the costs to remedy capacity shortfalls.

Table R.11 – Planning and Risk Medium Gas, Medium CO_2 PVRR by Study

Base/Base Case	PVRR	PVRR(d) (Benefit)/Cost of Retirement ($m)
C-01 (Benchmark)	$23,310	n/a
C-34	$23,180	($130)
C-35	$23,009	($301)
C-36	$23,286	($24)
C-37	$23,288	($22)
C-38	$23,002	($307)
C-39	$22,993	($317)
C-40	$23,483	$173
C-41	$23,600	$290

Table R.12 summarizes the stacked study results under the High/High price-policy scenario. As in the base/base price-policy scenario, Cases C-35, C-38, and C-39 show the largest potential benefits. Cases C-40 and C-41, both in excess of 1,000 MW of incremental early retirements relative to the benchmark case, continue to show a net cost.

Table R.12 – Planning and Risk High Gas, High CO_2 PVRR by Study

High/High Case	PVRR ($m)	PVRR(d) (Benefit)/Cost of Retirement ($m)
C-01 (Benchmark)	$28,176	n/a
C-34	$28,109	($67)
C-35	$27,897	($279)
C-36	$28,252	$76
C-37	$28,249	$72
C-38	$27,896	($280)
C-39	$27,877	($299)
C-40	$28,397	$221
C-41	$28,249	$368

Table R.13 summarizes the stacked study results under the low/zero price-policy scenario. As in the base/base and high/high price-policy scenarios, Cases C-35, C-38, and C-39 show the largest potential benefits, and the PVRR(d) results for these three cases are reasonably close. Cases C-40 and C-41, both in excess of 1,000 MW of incremental early retirements relative to the benchmark case, continue to show a net cost.

Table R.13 – Planning and Risk Low Gas, No CO_2 PVRR by Study

Low/Zero Case	PVRR ($m)	PVRR(d) (Benefit)/Cost of Retirement ($m)
C-01 (Benchmark)	$19,644	n/a
C-34	$19,487	($156)
C-35	$19,386	($257)
C-36	$19,549	($95)
C-37	$19.573	($71)
C-38	$19,359	($285)
C-39	$19,336	($308)
C-40	$19,747	$103
C-41	$19,828	$184

Initial Reliability Assessment

While the December 2018 stacked coal studies incorporated important enhancements in methodology and the alignment of data to the 2019 IRP planning assumptions, a method had not yet been fully developed to capture the operational and other system-reliability impacts associated with potential early coal unit retirements.

PacifiCorp performed an initial reliability assessment on a sampling of three cases using an hourly deterministic PaR run for 2023, which is the first full year after assumed coal unit retirements. The deterministic run provides the granularity necessary to represent system reliability shortfalls that may be lost in aggregated data, a factor of increasing importance as flexible resources are retired and potentially replaced with non-dispatchable variable resources. Because deterministic studies lack stochastic shocks, thermal units are modeled using de-rated capacity to account for unplanned outages.

For these initial reliability studies, system balances were summarized for load, net load (load net of energy efficiency, private generation, wind, and solar), spinning reserves, non-spinning reserves, and regulation reserves and compared to the type and amounts of resources providing system services across each hour of several selected days. Selected days included peak load days and peak net-load ramp days. Shortfalls were measured for spinning, non-spinning, and regulating reserves, as well as load. Table R.14 summarizes the aggregated findings of the initial reliability assessment.

Capacity shortfalls were observed in 2023, the year after early retirements, in each of the sample cases, and the number of occurrences and the magnitude of the worst occurrence increased in cases with more stacked retirements. The results confirmed that the retirement cases could degrade system reliability, and the potential cost to remedy these capacity shortfalls was not directly factored into the phase two results (i.e., via a potential addition or change in the resource mix to alleviate capacity shortfalls). Addressing these capacity shortfalls observed in the phase two results was the primary objective of phase three of the coal studies.

Table R.14 – Reliability Analysis Capacity Shortfalls

Case	Shortfall Hours	Maximum Shortfall (MW)
C-01 (Benchmark)	29 (0.3%)	290
C-35	146 (1.7%)	318
C-40	609 (7.0%)	351

Phase Three: Reliability Analysis of Coal Studies

From December 2018 through April 2019, PacifiCorp continued in its efforts to address the capacity shortfalls observed in preliminary results as part of this stage of the coal studies. Four public-input meetings were held including the April 25, 2019 meeting, which concluded the coal studies. During these months several shortfall mitigation enhancements were made to improve model representation, and a path forward was identified to address reliability concerns.

Stakeholder Feedback

As an outcome of the phase two stacked-retirement results, two additional cases were developed in response to stakeholder interest, cases C-42 and C-43. Case C-42 examined the impacts of retiring the four coal units most consistently reporting high customer benefits over the course of the coal studies. C-43 examined the impacts of replacing a Jim Bridger unit with a Dave Johnston unit. Table R.15 provides the assumed retirements of the two additional cases plus the total retired nameplate capacity assumed for each case.

Table R.15 – Additional Stacked Coal Studies

Case Name	2022 Retirements	Nameplate Retired (MW)
C-42	Naughton 1-2 (2022) Jim Bridger 1-2 (2022)	1,063
C-43	Naughton 1-2 (2022) Jim Bridger 1 (2022) Dave Johnston 3 (2022)	928

Coal Unit Focus

At the March 21, 2019 public-input meeting, PacifiCorp presented analysis of real levelized cost rankings of the coal units as an additional verification of the coal units which were to be the focus of the stacked-retirement cases. While this analysis is independent of direct locational factors tied to the IRP topology, the findings reported in Table R.16 generally confirms the focus of specific units established by the phase two coal studies completed in December, 2018.

Table R.16 – Real Levelized Cost Rankings of Coal Units

	Real Levelized Cost Rankings				
	Aggregate Rank	O&M Rank	CapEx Rank	Full Load Fuel Rank	Dec 3-4 PVRR(d) Rank
C-02 (Colstrip 3)	14	7	5	18	15
C-03 (Colstrip 4)	12	6	3	16	10
C-04 (Craig 1)	6	3	14	9	11
C-05 (Craig 2)	5	4	4	10	7
C-06 (Dave Johnston 1)	19	11	21	19	13
C-07 (Dave Johnston 2)	20	10	20	20	21
C-08 (Dave Johnston 3)	21	9	22	21	6
C-09 (Dave Johnston 4)	22	12	19	22	11
C-10 (Hayden 1)	1	1	10	1	4
C-11 (Hayden 2)	2	2	16	3	9
C-12 (Hunter 1)	11	14	12	11	19
C-13 (Hunter 2)	15	15	13	14	18
C-14 (Hunter 3)	13	18	15	12	22
C-15 (Huntington 1)	18	17	17	15	17
C-16 (Huntington 2)	16	16	18	13	14
C-17 (Jim Bridger 1)	7	20	2	6	2
C-18 (Jim Bridger 2)	9	19	1	8	5
C-19 (Jim Bridger 3)	10	21	7	7	8
C-20 (Jim Bridger 4)	8	22	11	5	20
C-21 (Naughton 1)	4	5	6	4	1
C-22 (Naughton 2)	3	8	9	2	3
C-23 (Wyodak)	17	13	8	17	16

The top candidate list in both views include Naughton, Jim Bridger, Hayden and Craig units. While the Dave Johnston units were not indicated in this new analysis, Dave Johnston Unit 3 was retained in certain cases for completeness and in response to stakeholder interest.

Shortfall Mitigation

Renewable Regulation Reserves

Wind and solar resources with requisite contractual rights and controls can provide regulation reserves when forecasted output can be curtailed to free-up operating capacity on the system. Curtailment results in:

- Replacement energy cost (typically market)
- Lost renewable energy credit revenue, where applicable (only included where explicitly known)
- Lost production tax credits, where applicable

- Avoided taxes (Wyoming wind only)

To mitigate the impacts of curtailments, wind and solar resources with requisite contractual rights and controls were modeled as dispatchable resources in PaR.

Hydro Dispatch Configuration
To better account for the flexibility of dispatchable hydro resources, these resources were configured for spring months (February through May in this context) to maximize reserve capability by establishing a consistent monthly dispatch rather than shaping to load.

Non-Peak Front Office Transaction Modeling
Modeling enhancements that address the modeling of dispatchable wind, solar, and hydro resources can result in less energy to serve load, so their viability in mitigating operating-reserve shortfalls may be restricted by limits on market purchases. Recognizing that market conditions vary by season, front office transaction (FOT) limits, which were established with a focus on summer and winter peak-load periods, are increased during the spring and fall to align with firm transmission rights. The increase is from 1,425 MW to 2,277 MW in these periods.

Lewis River Hydro Project Refinement
The original and standard model configuration led PaR to use the Lewis River Hydro project to shave peak load using available energy over a sample week for a given month. Any remaining capacity was then available for use as operating reserves.

PacifiCorp tested and implemented a modeling enhancement allowing PaR to shave peak load, using available energy of a sample week for a given month, net of wind, solar, battery storage, energy efficiency, and private generation resources (i.e., net load). Any remaining capacity, but no less than 10 percent of the Lewis River Hydro project, is considered available for use as operating reserves.

Battery Storage Optimization
PacifiCorp initially attempted to mimic the model settings used to enhance PaR's use of the Lewis River Hydro project to improve its use of battery-storage resources (dispatch, charging, and reserve resources). However, unlike the Lewis River Hydro project, battery-storage resources do not have an established volume of energy to use over a sample week in a given month.

Given complexity of PacifiCorp's system, the PaR model experienced difficulty optimizing the dispatch for battery storage resources. To improve upon this shortcoming in the PaR model, PacifiCorp developed and tested a method to produce an optimized peak-shave/valley-fill profile for these resource outside of PaR that is based on load net of wind, solar, energy efficiency, and private generation resources in any given portfolio. Fixed hourly dispatch, charging, and operating reserves are entered as inputs to the PaR model. This was presented and discussed in the March 21, 2019 public-input meeting.

Model Granularity Cost-Driver Adjustment
At the January 24, 2019 public-input meeting, PacifiCorp discussed that differences between portfolios in some cases were contributing to differences in reserve deficiencies (primarily 2038). These portfolio differences were causing disproportionate impacts on present-value portfolio costs in PaR relative to the SO model. Subsequent testing confirmed that differences in the granularity

between the two models contributes to alternative resource selections and that these resource selections are influencing these seemingly incongruent results.

When cost-driver adjustments based on the differences in hourly granularity between the SO model and PaR model are applied to resource cost inputs used in the SO model, differences to resource portfolio results for seemingly similar cases are more stable and the cost disparity driven by reserve deficiencies are mitigated. Accounting for the reduced hourly granularity in the SO model yields the average solar and wind resource costs shown in Table R.17.

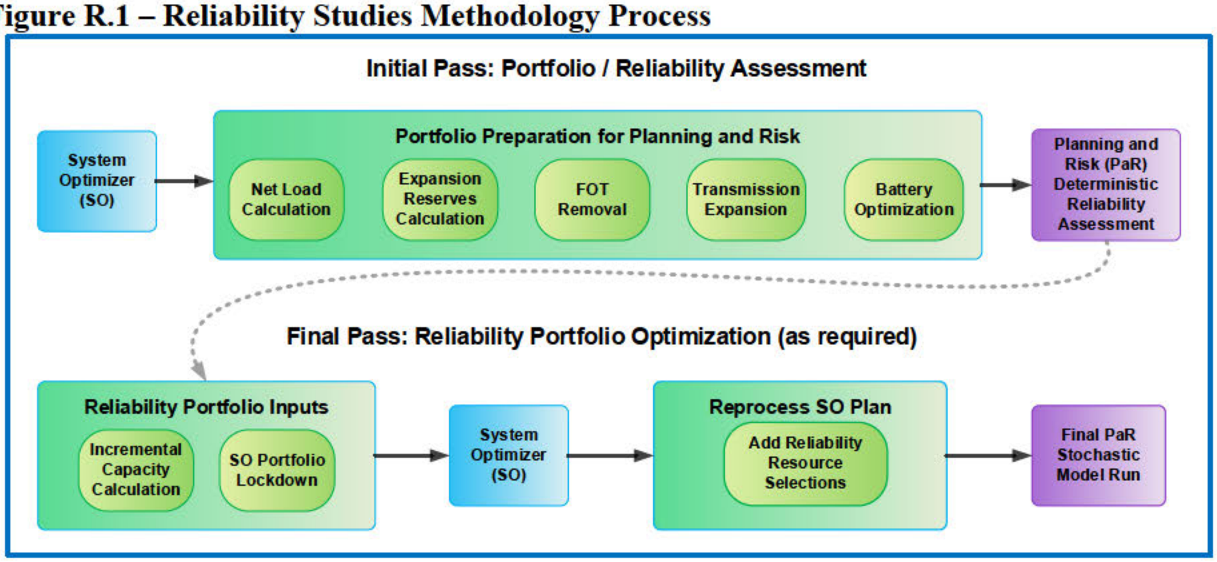
Table R.17 – Model Granularity Cost-Driver Adjustment Summary

Resource Location	Average Resource Cost (increase)/decrease ($/MWh of expected output)	
	Solar	Wind
Oregon	($7.06)	$0.95
Washington	($7.17)	$1.05
Idaho	($7.28)	($0.14)
Utah	($7.73)	($0.35)
Wyoming	($7.33)	($0.90)

Reliability Study Methodology

The modeling enhancements previously described give the SO model and PaR improved insight into the value and capabilities of various resources, and are applicable to every case. This allows the SO model to provide portfolios that are better-aligned with how PaR evaluates the performance and reliability of resources in its more granular perspective. In addition, due to the unique combination of resource types, locations and timing, and their interactions with transmission option modeling, a methodology was necessary to identify and address remaining reliability shortfalls on a case-by-case basis. This method was developed, tested and implemented, and subsequently presented to stakeholders at PacifiCorp's April 25, 2019 IRP public-input meeting. Figure R.1 outlines the development steps followed in this process.

Figure R.1 – Reliability Studies Methodology Process



The reliability methodology is an expansion of the initial reliability analysis explored at the end of 2018 and previously described in Stage Two of the coal studies and is described in more detail below.

Deterministic Reliability Assessment
In the initial reliability analysis, a single deterministic run for the year 2023 was used to assess reliability shortfalls. The methodology adopted in this reliability stage includes a deterministic reliability assessment for three years, 2023, 2030, and 2038. Years 2030 was added as an outcome of a 20-year analysis which determined that 2030 was most frequently the year with highest measured shortfall. Likewise 2038 was added as a bookend, and also because the final year was observed to have relatively high shortfalls.

In evaluating the reliability of the deterministic studies, portfolios must meet four hourly requirements: energy, non-spinning reserve, spinning reserve, and regulation reserve. Separate requirements for East and West are developed in the methodology, but transfers are allowed up to transmission limits. Using the method described in the Initial Reliability Analysis above, the hourly balance of net load and all resource contributions were compared to calculate the shortfall or unused available capacity for each hour. The maximum hourly shortfall (or minimum available) is identified by season. The resulting measures describe four reliability requirements for each proxy year: summer east, summer west, winter east and winter west.

Reliability requirements for the test year 2023 were applied to simulation years 2023 through 2027. Requirements for the test year 2030 were applied to simulation years 2028 through 2036. Requirements for the test year 2038 were applied to simulation years 2037 and 2038.

Uncertainty Requirement
Deterministic studies have the advantage of increased detail through hourly granularity appropriate to identifying potential shortfalls in an increasingly complex system. In the absence of stochastic variance, these studies also reflect "perfect foresight" for the following assumptions:

- Normal load (1-in-2 exceedance)
- Average thermal outages in all hours
- Average hydro conditions
- Fixed variable energy resource generation profiles, and
- Average market prices without electric or natural gas price volatility and physical supply risks

Additional flexible capacity is required beyond the capacity needed to "cure" hourly shortfalls to reliably serve customers considering that the above factors vary from day to day and hour to hour and are not known in advance. To account for these intrinsic uncertainties, 500 MW of additional reliability requirement was added to address significant day-ahead, hour-ahead and real-time unknowns in market supply. This 500 MW capacity requirement is in addition to capacity to sufficient to cover the maximum hourly shortfall identified in the deterministic studies.

The 500 MW incremental requirement relative to a deterministic forecast of loads, outages, market prices, and hydro generation was established upon review of operational data and with consideration of operational experience. In operations, capacity held in reserve for contingency, forecast error and intra-hour variability is approximately 16 percent of peak load. In the summer months, additional capacity is held in reserve to mitigate risks associated with high volatility in load and resource availability. In 2018, capacity held in reserve that is incremental to the 13 percent planning margin for contingency, forecast error, and intra-hour volatility totaled 295 MW. In 2018, capacity held in reserve to mitigate risk during peak load conditions in the summer months was approximately 241 MW. Combined, these sum to 536 MW. PacifiCorp conservatively adopted the 500 MW figure for planning purposes in the 2019 IRP.

Reliability Portfolio

Once the reliability requirements are known, the SO model is run with the ability to add or accelerate the following resource types relative to the pre-reliability portfolio to meet seasonal east and west incremental requirements: batteries, energy efficiency, gas peaking resources, and pumped storage resources. Other resource types are locked-in at levels determined by the pre-reliability portfolio. The four types of reliability resources are allowed as additions because they provide the necessary flexibility to effectively meet identified shortfalls.

Stochastic Outcomes

The last step in the process is to run a 20-year, 50-iteration PaR study on the resulting reliability portfolio, providing stochastic risk analysis over the full IRP study period.

Reliability Study Results

Table R.18 summarizes the assumed retirements for the complete set of stacked coal reliability cases, including retired capacity and PaR model measured (benefit)/cost.

Table R.18 – Early Retirement Assumptions Summary for all Reliability Coal Studies

Case	Inc. Retired Capacity in 2023 (MW)	PVRR ($m)	Naughton 1	Naughton 2	Bridger 1	Bridger 2	Hayden 1	Hayden 2	Craig 1	Craig 2	Dave Johnston 3
C-34	357	$23,536	✓	✓							
C-35	711	$23,381	✓	✓	✓						
C-36	510	$23,418	✓		✓						
C-37	554	$23,405	✓		✓		✓				
C-38	755	$23,398	✓	✓	✓		✓				
C-39	834	$23,434	✓	✓	✓		✓			✓	
C-40	1,193	$23,317	✓	✓	✓	✓	✓			✓	
C-41	1,529	$23,390	✓	✓	✓	✓	✓	✓	✓	✓	✓
C-42	1,063	$23,302	✓	✓	✓	✓					
C-43	928	$23,458	✓	✓	✓						✓

Note: in all cases it is assumed that Naughton 3 (280 MW) is retired in 2019 and that Cholla 4 (387 MW) is retired at the end of 2020; these units are retired in the benchmark case and therefore not incremental to the stacked-retirement cases listed above.

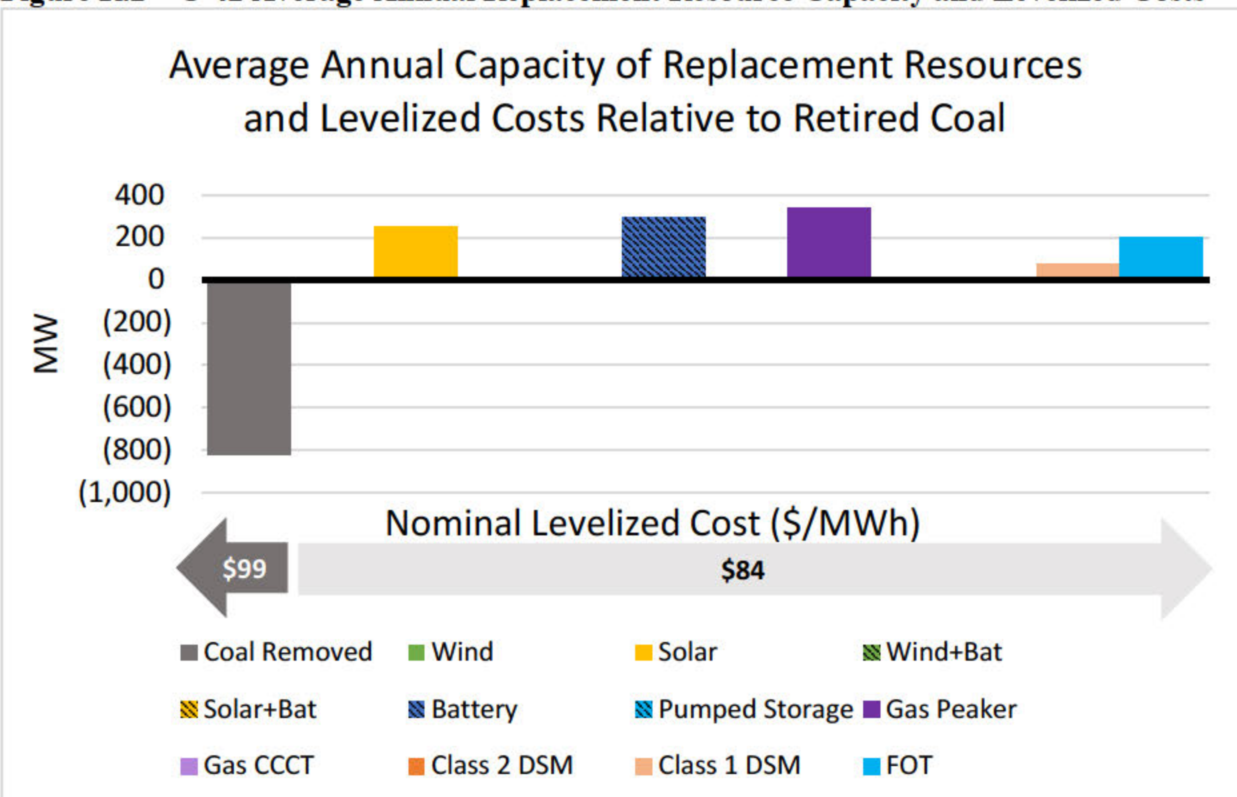
In the final coal study analysis, case C-42 produced the lowest present value revenue requirement (PVRR) total system cost, and therefore the highest potential customer benefits associated with potential early retirement. Cases retiring greater amounts of coal resource (C-40, C-41), or those emphasizing different coal units for early retirement (C-43) reported reduced benefits. This outcome is broadly supported by findings from phase one and two, and again by the real levelized cost rankings of coal unit run-rate costs across the fleet, as reported previously in Table R.16.

Stacked Coal Case C-42

At the April 25, 2019 public-input meeting, PacifiCorp reported a PVRR differential benefit of \$248m against the C-01 benchmark case. As noted in the Unit-by-Unit Methodology discussion, above, the benchmark was an administratively established in phase one of the coal studies, and is not representative of PacifiCorp's plan. Also, the \$248m figure did not include a correction to the granularity adjustment driver included in the reliability coal studies. Corrected, the PVRR values (given in Table R.18, above) did not alter the conclusions of the April 2019 analysis, which continue to confirm that the greatest potential benefit for early retirements resides with the potential early closure of units at the Naughton and Jim Bridger plants in Wyoming.

Aligned with the April 25, 2019 results, Figure R.2 reports the average annual cost of replacement resources and levelized costs relative to the assumed 2022 accelerated retirements of Jim Bridger Units 1 and 2, and Naughton Units 1 and 2.

Figure R.2 – C-42 Average Annual Replacement Resource Capacity and Levelized Costs



- The nominal levelized cost of retired coal resources is \$14.21/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 77.0 percent of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 26.3 percent to achieve break-even economics with the replacement portfolio.

Conclusions

The updated coal-retirement cases account for incremental resource costs to address reliability issues identified and discussed at the December 3-4, 2018 public-input meeting. The updated analysis shows there are potential customer benefits from accelerating the retirement of certain coal units, where the greatest customer benefits are associated with the potential accelerated retirement of units at the Naughton and Jim Bridger plants located in Wyoming.

Aligning with the long-term study plan established during the 2019 IRP public-input process, the identification of these key units informed PacifiCorp's 2019 IRP portfolio-development process, described in detail in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). The portfolio-development process considers other planning factors not fully evaluated in the coal studies (i.e., Regional Haze compliance, alternative retirement dates for jointly owned coal plants where PacifiCorp is a minority owner and not an operator, alternative timing of potential retirements when accounting for incremental capacity to maintain reliability). Consistent with the findings from the coal study, more than half of the cases developed in the initial phase of the portfolio-development process evaluated varying combinations of retirement dates for Naughton and Jim Bridger units, including coal retirement assumptions from case C-42.

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

SIERRA CLUB EXHIBIT 107

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to Sierra Club Data Request 1.6

This exhibit is confidential pursuant to Protective Order 16-128 and is provided in Excel format.

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

SIERRA CLUB EXHIBIT 108

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Sierra Club Coal Supply Agreements Workpaper

This exhibit is confidential pursuant to Protective Order 16-128 and is provided under separate cover.

Docket No. UE 375
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SIERRA CLUB EXHIBIT 109

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to Sierra Club Data Request 1.7

This exhibit is confidential pursuant to Protective Order 16-128 and is provided in Excel format.

Docket No. UE 375
Witness: Ed Burgess

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UE 375

SIERRA CLUB EXHIBIT 110

HIGHLY CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Highly Confidential PacifiCorp Response to Sierra Club Data Request 4.1

This exhibit is confidential pursuant to Modified Protective Order 20-145 and is provided under separate cover.

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

SIERRA CLUB EXHIBIT 111

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Selected Confidential Data Responses

This exhibit is confidential pursuant to Protective Order 16-128 and is provided under separate cover.

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

SIERRA CLUB EXHIBIT 112

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp Confidential Long-Term Fuel Supply Plan for
Jim Bridger Plan (Redacted Version)

PACIFICORP CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIDGER PLANT

March 2018

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

CONTENTS

1 INTRODUCTION AND EXECUTIVE SUMMARY

In the final order in PacifiCorp's 2014 Transition Adjustment Mechanism (TAM) filing, Order No. 13-387, the Public Utility Commission of Oregon (Oregon Commission) adopted PacifiCorp's proposal to prepare periodic fuel supply plans comparing affiliate mine supply to alternative fuel supply options, including market alternatives. In December 2015, PacifiCorp complied with Order No. 13-387 by providing "PacifiCorp's Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant" (2015 Fuel Plan). Subsequently, PacifiCorp committed in testimony to provide periodic updated filings to the 2015 Fuel Plan. In its orders in the 2017 and 2018 TAMs, the Oregon Commission directed PacifiCorp to hold workshops to discuss information and analyses required to meaningfully evaluate long-term fueling plans for the Jim Bridger plant. To date, three different workshops have been held with the Oregon staff and intervenors to discuss various details and assumptions associated with the development of the updated PacifiCorp Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant (2018 Fuel Plan).

As set forth in PacifiCorp's compliance filing in docket UE 287, the purpose of long-term fuel supply plans for plants fueled from captive mines is to determine the least-cost, least-risk coal supply evaluated on a multi-year basis. The long-term fuel supply plan is designed to ensure that fuel supplies are fair, just and reasonable, and that they satisfy the Oregon Commission's prudence and affiliate interest standards.

Additionally, PacifiCorp agreed to provide a long-term fueling strategy for the Jim Bridger plant in the stipulation Settlement Agreement to the 2015 Wyoming Energy Cost Adjustment Mechanism (ECAM) filing (docket 20000-472-EA-15). The evaluation would include coal supply pricing, transportation and modifications to the plant for an alternative fuel supply. The report would be updated periodically to address significant milestones.

To develop the 2018 Fuel Plan, PacifiCorp has studied, reviewed and evaluated different fueling options for the Jim Bridger plant. For the 2018 Fuel Plan, the annual generation requirements expressed in consumed tons were derived from PacifiCorp's budget which is calculated using PacifiCorp's Generation and Regulation Initiative Decision Tools (GRID) model[1]. The generation requirements derived from the GRID model have also been used for the basis of PacifiCorp's 2017 Integrated Resource Plan (IRP) Update. Within the 2018 Fuel Plan, different fueling options are presented. The fueling options consider varying tonnage delivery schedules sourced from Bridger Coal Company (Bridger mine), the Black Butte mine, and mines located in Wyoming's Southern Powder River Basin (SPRB), which are "8,800" Btu/lb. mines. Additionally, the different coal delivery options for the Bridger mine contain various mine plan scenarios outlining specified tonnage delivery schedules from both the underground and surface mining operations. Included in these different mine scenarios are estimated shutdown dates for Bridger mine's underground and surface operations. The 2018 Fuel Plan provides third party coal supply tonnages and pricing estimates based upon recent negotiations, as well as recent coal pricing forecasts from Energy Ventures Analysis (EVA). The 2018 Fuel Plan provides estimated tonnage volumes and rail rates for transportation services provided by the Union Pacific Railroad for the transport of coal from third party coal supply sources. The estimated plant modifications and capital requirements, defined by equipment category, as well as total costs needed to support large volumes of SPRB coal are presented in a detailed third party study completed in 2017 by the engineering and consulting firm Burns & McDonnell.

[1] The GRID model used for budget purposes is different than the GRID model used in the Oregon TAM. The budget GRID model is used to determine the net power cost budget, but is not subject to the same normalizing and regulatory modeling constraints as the GRID model used in the Oregon TAM.

After considering all of the factors influencing long-term fueling strategy, the Company developed and evaluated six different Jim Bridger plant fueling options. A Present Value Revenue Requirement (PVRR) calculation was completed for the various fueling options and includes a composite ranking considering both financial and risk weighting. Based upon the results of the detailed PVRR analysis and utilizing a risk profile, Option F ([redacted]) is the current least-cost, least-risk option. While the current analyses shows Option F as the least-cost, least-risk option, Option D is the lowest cost option and will continue to be analyzed. PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant taking in to consideration both cost and risk of the different options and will change the long-term fuel supply plan as necessary to provide the least-cost, least-risk fuel supply for the Jim Bridger plant.

The benefits of pursuing Option F as the long-term fueling strategy for the Jim Bridger plant include the following:

- [redacted]
- [redacted])
- [redacted]
- [redacted]
- [redacted]
- [redacted]

2 BACKGROUND

The Jim Bridger plant is a four unit coal-fired plant located in Sweetwater County, Wyoming. The facility is located approximately eight miles north of Point of Rocks, Wyoming, and approximately 24 miles east of Rock Springs, Wyoming.

The Jim Bridger plant is the largest power plant on the PacifiCorp system (2,120 megawatts) and is jointly owned by PacifiCorp (66.7%) and Idaho Power Company (Idaho Power) (33.3%). The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net megawatt capacity. Over the past two years, Jim Bridger plant has consumed approximately 6.6 million tons of coal per year. From 2006 to 2015, the Jim Bridger plant consumed on average 8.0 million tons per year. The plant is designed to burn coal sourced from southwest Wyoming with heat content in the range of 9,000 Btu/lb. to 10,000 Btu/lb. The depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2025 in Oregon and through 2037 in all other states based on PacifiCorp's 2012 depreciation study.

The Bridger mine is located adjacent to the Jim Bridger plant. The Bridger mine includes both surface and underground mining operations and, similar to the Jim Bridger plant, is jointly owned by PacifiCorp (66.7%) and Idaho Power (33.3%). The surface operation consists of a combination dragline and truck/loader operation that produces approximately [redacted] million tons of coal per year. Bridger mine's underground operation uses continuous miners and longwall mining equipment to produce coal. The underground mine produces approximately [redacted] million tons of coal per year. The coal is transported from both the underground and surface mining operations to surface stockpiles or directly to the Jim Bridger plant via a nine mile overland conveyor system.

For regulatory purposes, Bridger mine is consolidated with PacifiCorp's operations. PacifiCorp's share of Bridger mine is included in the PacifiCorp rate base and its share of mining costs, including depreciation and depletion, is included in net power costs.

In addition to the estimated [redacted] million tons of coal forecast to be delivered annually from the Bridger mine to the Jim Bridger plant, the Jim Bridger plant has historically received the remaining portion of its coal supply requirements, approximately [redacted] million tons per year, from the nearby Black Butte mine. The Union Pacific Railroad provides rail access for all the coal delivered from the Black Butte mine to the plant.

3 ASSUMPTIONS

The 2018 Fuel Plan for the Jim Bridger Plant was prepared in two phases. The key variables used in the plan were subject to in-depth review and study. These assumptions are explained below:

3.1 Evaluation – Phase 1

3.1.1 Generation

Generation assumptions are taken from PacifiCorp's budget GRID model and parallel PacifiCorp's 2017 IRP Update which will be submitted in May 2018, and are used in all evaluated alternatives. Consistent with the findings of the IRP, the 2018 Fuel Plan assumes the closure of Jim Bridger Unit 1 on December 31, 2028, and Jim Bridger Unit 2 on December 31, 2032. These assumptions represent a significant change from the assumed generation requirement used to evaluate the plant's fueling needs in the 2015 Fuel Plan. This plan assumed a total plant annual consumption of [redacted] million tons through the life of the plant.

Consistent with the IRP, coal consumption is shown to decline through 2037, the depreciable plant life. The assumed burn level is approximately [redacted] million tons per year for 2018 through 2022; approximately [redacted] million tons per year for 2023 through 2028; approximately [redacted] million tons per year for 2029 through 2032; and approximately [redacted] million tons per year through 2037. The assumed generation levels between the 2015 and 2018 Fuel Plans are compared in Appendix A.

3.1.2 Plant Depreciable Life

The assumed depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2025 in Oregon and through 2037 in all other states, based on PacifiCorp's 2012 depreciation study.

3.1.3 2015 Fuel Plan –"Base Operating Plan"

The 2015 Fuel Plan recommended fueling the plant under the Base Operating Plan. This plan consisted of the following main elements:

- Continued surface mining at Bridger mine through [redacted]
- Permitting and mining the Deadman Wash tract at Bridger mine
- Closure of the Bridger mine underground operations in [redacted] – remaining inventory delivered in [redacted]
- Continued purchase of Black Butte mine coal through [redacted]
- Conversion of the Jim Bridger plant to SPRB coal deliveries requiring estimated capital expenditures of [redacted] million (PacifiCorp share)
- [redacted] SPRB deliveries, replacing Black Butte coal deliveries, begin in [redacted] and continue through [redacted]
- Infrastructure improvements begin in [redacted] with infrastructure fully in place and operable by [redacted]

As mentioned above, the Base Operating Plan was recommended based on the assumption that Jim Bridger plant consumption would be between [redacted] and [redacted] million tons per year (total plant). Actual plant coal consumption for 2016 and 2017 was significantly less than the assumed consumption. Total coal consumption at the plant was [redacted] than expected in the Base Operating Plan over the two-year period as shown in Table 1.

TABLE 1

"Base Operating Plan" - 2015 Long-Term Fuel Supply Plan for the Jim Bridger Plant						
	2016		2017		Average	
	PacifiCorp	Total	PacifiCorp	Total	PacifiCorp	Total
Deliveries (Million Tons)						
Bridger Coal Company	[redacted]					
Black Butte Coal Company						
Consumption (Million Tons)						
Total						
Actual Tonnage Consumed at the Jim Bridger Plant						
	2016		2017		Average	
	PacifiCorp	Total	PacifiCorp	Total	PacifiCorp	Total
Deliveries (Million Tons)						
Bridger Coal Company	[redacted]					
Black Butte Coal Company						
Consumption (Million Tons)						
Total						
Variance in Tonnage Consumed at the Jim Bridger Plant						
	2016		2017		Average	
	PacifiCorp	Total	PacifiCorp	Total	PacifiCorp	Total
Deliveries (Million Tons)						
Bridger Coal Company	[redacted]					
Black Butte Coal Company						
Consumption (Million Tons)						
Total						
% Change						

The significant decrease in forecasted consumption required revisions to the recommended Base Operating Plan. [redacted] Effective March 2017, the Base Operating Plan was modified to include this change.

3.1.4 Further Refinement of the "Base Operating Plan"

In addition to the change mentioned above, an additional step was taken to further optimize the Base Operating Plan by determining the optimal closure plan for the Bridger mine underground mining operation. Bridger mine prepared four, [redacted] mine plans with varying underground closure dates. The mine production volume target was based on estimated consumption and purchases of third party coal. The four plans are summarized below:

- Underground Mine Option A –
  - Underground closure in [redacted]
  - Surface closure in [redacted]
- Underground Mine Option B –
  - Underground closure in [redacted]
  - Surface closure in [redacted]
- Underground Mine Option C –
  - Underground closure in [redacted]
  - Surface closure in [redacted]
- Underground Mine Option D –
  - Underground closure in [redacted]
  - Surface closure in [redacted]

Bridger mine's underground operations experienced a significant challenge with the mine's western reserves in 2015 and 2016. Based on knowledge gained from this experience, the Bridger mine reduced planned production in the area and accelerated the move to the mine's eastern reserves. Ultimately Underground Mine Option D with the underground closure in [redacted], emerged and was found to be the least-cost, least-risk option. Table 2 compares the results of the analysis in terms of (PVRR):

TABLE 2

PVRR Summary		
PVRR Summary (PacifiCorp Share)	PVRR (000's)	Differential (from lowest $)
[redacted]		
Financial Ranking & Operation Risk Ranking		
PVRR Summary (PacifiCorp Share)	Financial Ranking (low to high)	Operation Risk Ranking (low to high)
[redacted]		

The results of this analysis were presented to Oregon Commission staff in a workshop held March 1, 2017. The analysis established the Base Operating Plan as modified, consistent with Underground Mine Option D above as the new baseline for continued evaluation.

Underground Mine Option D – The March 2017 Base Operating Plan consists of the following main elements:

- Continued surface mining at Bridger mine through [redacted]
- Permitting and mining the Deadman Wash tract at Bridger mine
- Closure of Bridger mine underground operations in [redacted]
- Continued purchase of Black Butte mine coal through [redacted]
- SPRB coal deliveries from [redacted] continuing through [redacted] in quantities which will not require significant capital modifications at the plant

3.2 Evaluation – Phase 2

3.2.1 Economic closure of the Bridger mine surface operation

With the March 2017 Base Operating Plan established and the underground mine closure date determined, Bridger mine prepared three, [redacted] million ton per year mine plans. This level of production complemented expected future total plant consumption of [redacted] million tons per year and third party purchases. One of the options also considered was a complete conversion to SPRB deliveries as soon as practicable. The three mine plans are summarized as follows:

- Surface Mine Option D –
  - Underground closure in [redacted]
  - Surface closure in [redacted]
- Surface Mine Option E –
  - Underground closure in [redacted]

    - Surface closure in [redacted]
- Surface Mine Option F –
    - Underground closure in [redacted]
    - Surface closure in [redacted]

The revised Surface Mine Option D mine plan maintained assumptions consistent with those described above for the March 2017 Base Operating Plan, except the assumed Bridger mine production level was reduced to reflect deliveries of [redacted] million tons per year from the [redacted] million tons per year level mentioned previously.

A fueling plan option based on Bridger mine's Surface Mine Option E mine plan assumed a complete conversion to the consumption of SPRB coal following the closure of both underground and surface mining operations at Bridger mine in [redacted]. A complete conversion was not possible prior to [redacted], due to the capital modifications required at the Jim Bridger plant to safely and reliably receive and consume SPRB coal in large volumes. As a result, the fueling options have been separated into "near-term" and "long-term" periods for discussion purposes. For purposes of the 2018 Fuel Plan, the near-term period has been defined as the next three-to-four years and corresponds to the estimated time required to design, procure and construct the capital infrastructure to successfully unload trains and consume coal originating in the SPRB.

Surface Mine Option F further developed Surface Mine Option D. The key change was the assumption of [redacted], avoiding [redacted] million ([redacted] million PacifiCorp share) in development costs, and closure of the Bridger mine surface mining operation in [redacted]. After closure of the Bridger mine surface mining operation, Surface Mine Option F supplements the Bridger mine deliveries with coal from both the [redacted].

3.2.2 Third Party Coal

Based on the location of the Jim Bridger plant, economic fuel supply alternatives are limited to two operating mines located in southwest Wyoming and the SPRB mines of Campbell County, Wyoming.

The Black Butte mine, 20 miles southeast of the Jim Bridger plant, is jointly owned by Lighthouse Resources Inc. (Lighthouse) and Anadarko Petroleum. Operated by Lighthouse, the mine is a multiple seam, multiple pit operation with the overburden removed by draglines and a truck/loader fleet. Historically, Black Butte mine has mined approximately 3.5 to 4.0 million tons per year, a significant portion of which has supplied the Jim Bridger plant. However, one of Black Butte mine's significant contracts has expired. The mine is now producing less than [redacted] million tons per year and the Jim Bridger plant is the mine's only customer. During 2016 and 2017, the Jim Bridger plant received approximately one-third of its fuel supplies from the Black Butte mine under a contract that will terminate in [redacted]. Coal from the Black Butte mine is delivered by rail to the Jim Bridger plant under an agreement with the Union Pacific Railroad.

The other southwest Wyoming mine is Westmoreland's Kemmerer mine. In 2017, Westmoreland purchased the idled Haystack mine located 30 miles south of the Kemmerer mine. Presently the Kemmerer mine supplies PacifiCorp's Naughton plant and southwest Wyoming's trona (soda ash) industry. The Kemmerer mine coal is delivered to customers via overland conveyor, truck transportation and limited rail operations. Presently the Kemmerer mine's rail loading infrastructure is incapable of loading a full unit train efficiently. In addition, the grade elevation surrounding the mine requires additional locomotives to power a full unit train. As a result, the mine very rarely loads full unit trains. Given the Kemmerer mine's current rail loading infrastructure, rail delivery of coal would only be viable on a limited scale. Delivery of a sizable volume of Kemmerer coal to the Jim Bridger plant would require more costly truck transportation. [redacted].[2]

The Powder River Basin is the largest coal mining region in the United States. Coal from the SPRB is classified as sub-bituminous coal. SPRB coal contains an average heat content of approximately 8,800 Btu/lb. The coal mined in the SPRB is low sulfur and low ash. Due to its unique quality characteristics, SPRB coal has been consumed by energy markets in multiple states across the country. In 2017, there were eight different mining companies operating fourteen active mines in the Powder River Basin, producing roughly 300 million tons. SPRB mines contain the highest heat content coal ranging between 8,600 Btu/lb. and 8,950 Btu/lb. These mines are located about 550 miles from the Jim Bridger plant.

SPRB mines are served by the Union Pacific Railroad and Burlington Northern Santa Fe Railway railroads. Both of these railroads have joint access to all of the mines located south of Gillette, Wyoming, in the SPRB.

3.2.3 Black Butte Pricing

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[2] See footnote [redacted].

TABLE 3

CONTRACT PROPOSALS - ANNUAL VOLUME & PRICING					
Proposal A	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal B	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal C	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal D	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal E	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					

The least-cost, least-risk option for the near-term was identified by comparing the cost of purchasing incremental volume from Black Butte mine to the cost of producing incremental volume at Bridger mine. The comparison consisted of the following two options:

1. [redacted] (Black Butte mine Proposal A)
2. [redacted] (Black Butte mine Proposal D)

Other options were considered and evaluated, but were found to not be economically viable. Specifically, an option considering Bridger mine deliveries at [redacted] million tons per year and Black Butte mine deliveries at [redacted] million tons per year is discussed in the following pages.

The Company ultimately selected Black Butte mine's Proposal A as the least-cost, least-risk coal supply option for the near-term. Proposal A preserves flexibility to further assess and implement long-term fuel options before making any long-term, large capital investments. Table 4 details the delivered cost savings of [redacted] million to PacifiCorp from purchasing coal under the selected option:

TABLE 4

PacifiCorp Share						
[redacted] (Black Butte Mine - Proposal A)						
Mine	*2018*	*2019*	*2020*	*2021*	*2022*	*Total*
Bridger Mine						
Tons	[redacted]					
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Black Butte Mine						
Tons	[redacted]					
Btu/lb						
Mmbtus						
$/Ton						
Rail Rate $/Ton						
Total Coal Dollars						
Total Rail Dollars						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Total Deliveries						
Tons						
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
[redacted] (Black Butte Mine - Proposal D)						
Mine	*2018*	*2019*	*2020*	*2021*	*2022*	*Total*
Bridger Mine						
Tons	[redacted]					
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Black Butte Mine						
Tons						
Btu/lb						
Mmbtus						
$/Ton						
Rail Rate $/Ton						
Total Coal Dollars						
Total Rail Dollars						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Total Deliveries						
Tons						
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
VARIANCE						
	2018	*2019*	*2020*	*2021*	*2022*	*Total*
Tons	[redacted]					
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Calculation of Price Savings - [redacted]						
MMBtu Delivered Variance						[redacted]
*Multiplied by [redacted] (Proposal D) MMBtus						
Price Savings						

Concurrent negotiations were held with Union Pacific Railroad for coal transportation from the Black Butte mine. The delivered costs shown in the above Table 4 includes rail transportation rates consistent with the negotiations. The estimated savings shown in the table represents PacifiCorp's share of the total savings.

Upon the expiration of the near-term 2018 contract with Black Butte mine, the pricing for Black Butte mine coal is assumed to increase at [redacted] per year.

3.2.4 Powder River Basin Coal in the Near-Term

Powder River Basin coal has a high propensity to spontaneously combust, and is the most friable coal type burned in the power industry. While major plant modifications would be required to safely and reliably receive and consume large volumes of SPRB coal at the Jim Bridger plant, the plant is likely capable of consuming SPRB coal on a limited scale without major modification to the plant's coal unloading or coal consuming infrastructure. For example, in a test burn in 2015, the plant handled and consumed 10 trains totaling 140,540 tons of SPRB coal. Based on knowledge gained from the test burn and PacifiCorp's professional judgement, plant management believes that up to [redacted] tons of SPRB coal per year might be safely and reliably consumed without major modifications to the plant. This estimate is considered to be aggressive.

PacifiCorp considered the possibility of reducing the amount of coal purchased from the Black Butte mine and purchasing a small amount, up to [redacted] tons (PacifiCorp share), from a SPRB coal mine on an annual basis. As shown in Table 5, the purchase of small volumes of SPRB coal was not the least-cost option.

For example, PacifiCorp has chosen to purchase [redacted] tons per year[3] of incremental coal from Black Butte mine under Proposal A, [redacted]. PacifiCorp has also chosen to forego the purchase of [redacted] tons per year of coal from Bridger mine (or SPRB coal) that would have been required if Black Butte mine Proposal D, [redacted], had been elected. Average costs for the [redacted] annual incremental ton variances can be derived from the proposals and mine plans outlined in Table 4 and are shown for both the Black Butte mine and Bridger mine in Table 5. The estimated average delivered cost of [redacted] tons of SPRB coal is also shown. On a delivered \$/MMBtu basis, the estimated average delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] than the delivered cost of Black Butte mine's incremental coal [redacted] over the term of the proposals. In addition, the estimated delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] over the four year term than the incremental cost of coal mined at the Bridger mine [redacted].

As shown in Table 5, this relationship also holds when comparing deliveries under Black Butte mine Proposal A and Black Butte mine Proposal B, [redacted]. If Proposal B was chosen, PacifiCorp would forego the purchase of [redacted] tons of the [redacted] total incremental tons available under Black Butte mine Proposal A. On a delivered \$/MMBtu basis, the estimated average delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] than the delivered cost of Black Butte mine's incremental coal [redacted] over the term of the proposals. In addition, the estimated average delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] over the four year term than the incremental cost of coal mined at the Bridger

[3] Represents PacifiCorp's share of the [redacted] differential between Proposal A and Proposal D (difference between [redacted])

mine [redacted]. The concept of PacifiCorp purchasing fewer tons from Black Butte mine and replacing that volume with a small amount, from [redacted] tons up to [redacted] tons, of SPRB coal (or coal from Bridger mine) was eliminated in the near-term based on these findings.

PacifiCorp also considered accepting Black Butte mine Proposal B, [redacted], and simultaneously [redacted] Bridger mine deliveries by [redacted] tons per year to [redacted] million tons per year, on a total mine basis. Based on data shown in Table 5, in accepting Proposal B, PacifiCorp would purchase [redacted] tons of the [redacted] total incremental tons available from Bridger mine at an [redacted] premium over the cost of purchasing the coal from Black Butte mine. As a result, PacifiCorp chose to forego the purchase of [redacted] tons from the Bridger mine at an incremental cost of [redacted] in favor of purchasing the [redacted] incremental tons from Black Butte mine at an incremental cost of [redacted].

TABLE 5

Incremental Cost For Black Butte Proposal Term					
		SPRB	**Bridger**	**Black Butte (Prop. A - Prop. D)**	**Black Butte (Prop. A - Prop. B)**
Coal	$	[redacted]			
Freight	$				
$/Ton	$				
Btu/lb					
$/mmBtu	$				[4]

3.2.5 Black Butte Mine Volume

PacifiCorp conducted a high-level review of the Lighthouse Resources Inc. Black Butte mine coal resource and reserve estimates in 2015. The study consisted of reviewing available third-party Black Butte reserve and geology documents, along with Black Butte's geology information and permitting status. At the time, based on the information reviewed, the conclusion of the review was that Black Butte mine had [redacted] million tons that could be considered economic coal reserves under the terms and conditions of the then-current contract.

For assumed Black Butte mine production in the 2018 Fuel Plan, PacifiCorp has updated these reserve estimates. The estimated reserves have been [redacted] since the date of the 2015 reserve review, and have [redacted] based on discussions with Lighthouse [redacted] As of that date, Black Butte mine claimed permitted reserves of [redacted]

[4] Consistent with Table 4, incremental prices shown are weighted over the near-term, with exception of the SPRB pricing. SPRB prices are averaged over four years with equal annual volumes.

- 2018 Fuel Plan Option D – [redacted]
- 2018 Fuel Plan Option F [redacted]
- 2018 Fuel Plan Option F – [redacted]

3.2.6 Assumed SPRB Coal Pricing

Due to the Jim Bridger plant's distance from the SPRB, roughly 550 miles by rail, the Jim Bridger plant would source SPRB coal from the mines with the highest heat content (Btu/lb.) The economics of the purchase decision would target coal originating from three mines in the SPRB, Cloud Peak Energy Resources LLC's Antelope mine, Peabody COALSALES, LLC's North Antelope Rochelle Mine and Arch Coal Sales Company Inc.'s Black Thunder mine. These mines typically sell coal on an 8,800 Btu/lb. basis as opposed to other areas of the Powder River Basin that sell 8,400 Btu/lb. or lesser heat content coals.

The Powder River Basin is the largest coal mining region in the United States. As a result, standard 8,800 Btu/lb. and 8,400 Btu/lb. Powder River Basin coal is routinely traded, indexed and forecast. Assumed SPRB coal pricing used in the 2018 Fuel Plan is based on a long-term coal forecast published by EVA in September 2017.

3.2.7 Transportation

Bridger mine coal is delivered to the plant via conveyor belt, and the cost of conveying the coal is included in the delivered coal cost. The Jim Bridger plant is also connected by a rail spur to the Union Pacific Railroad mainline track. Union Pacific Railroad has the trackage rights to the mainline and spur to the Jim Bridger plant and, as a result, the Jim Bridger plant is captive to the Union Pacific Railroad for deliveries by rail. Deliveries from all sources other than Bridger mine are assumed to be delivered by the Union Pacific Railroad.

UNION PACIFIC RAILROAD INDICATIVE PRICING

Early in 2017, PacifiCorp requested that Union Pacific Railroad provide indicative rates to aid in evaluating increased SPRB coal deliveries to the Jim Bridger plant with an estimated start-up in [redacted]. PacifiCorp requested rates for deliveries ranging from [redacted] million tons per year. To better understand potential price discounts for added volume, rates for deliveries in both PacifiCorp and Union Pacific Railroad railcars were requested at various volume levels in the [redacted] per year range.

Union Pacific Railroad provided indicative rates in June 2017. The rates applied to the volume range previously specified, from [redacted] per year up to [redacted] per year and were provided in current dollars. However, Union Pacific Railroad did not provide information on volume discounts for specific volume ranges as requested, nor did Union Pacific Railroad provide specific rates for deliveries in PacifiCorp or Union Pacific Railroad railcars. Instead, it provided an estimated freight rate for planning purposes in the range of [redacted] per net ton, which included railroad owned railcars, but excluded a fuel component and quarterly escalation.

Union Pacific Railroad contract pricing

In 2017, while negotiations took place with Black Butte mine for near-term coal supplies, near-term rail transportation negotiations were also conducted with Union Pacific Railroad. Similar to the Jim Bridger plant, the Black Butte mine is connected by a rail spur to Union Pacific Railroad's mainline track. Negotiations with Union Pacific Railroad concluded with a signed contract in February 2018. The transportation agreement includes the following key provisions as of January 1, 2018:

- Minimum volume: [redacted]
- Maximum volume: [redacted]
- Rail rates provided for shipments from:
  - Lighthouse's Black Butte mine - [redacted]
  - Wyoming's SPRB region - [redacted]
  - Westmoreland Kemmerer, LLC's Kemmerer mine located in Lincoln County, Wyoming - [redacted]
  - Peabody's Twentymile mine located in Routt County, Colorado - [redacted]
- All rates subject to escalation and fuel surcharge

Use of indicative and contract pricing

For SPRB deliveries, the lower end of the indicative rate range, [redacted] per ton, is used as of January 1, 2018, in any fueling option where more than [redacted] per year are delivered to the plant. This rate is then escalated at [redacted] (provided by IHS/Global Insights in Q3 2017) per year thereafter.

When SPRB deliveries are less than [redacted] per year, the contract rate is applied. For example, a [redacted] per ton contract rate is used as of January 1, 2018, in fueling options where only small volumes of SPRB coal is delivered to the plant. This rate is also escalated at a rate of [redacted] per year thereafter.

PacifiCorp owns 121 aluminum bottom-dump railcars with a net payload of 105 tons per car. Consistent with current operating practice for Black Butte mine deliveries, the [redacted] per ton rate is used and is escalated at a rate of [redacted] per year.

3.3 CAPITAL

PacifiCorp selected the consulting firm Burns & McDonnell (BMcD) to perform an independent capital evaluation of the plant modifications and capital expenditures required at the Jim Bridger plant to consume volumes, up to 100%, of SPRB coal. BMcD completed a comprehensive study in June 2017. The study outlined high priority plant modifications and the estimated costs in converting the Jim Bridger plant's main fuel source to SPRB coal. The study focused on required modification to several systems including coal handling & storage, rail delivery, mechanical process/power island, electrical, substation and overhead distribution and air permitting.

The required coal handling system modifications identified engineering controls that would be needed and relied upon to reduce and mitigate coal dust throughout the coal handling system. The study emphasized the importance of having adequate wash down capability by installing and utilizing fixed pipe wash down systems in existing coal reclaim and conveyor tunnels, crusher houses, tripper bays and in the rail unloading hopper facilities. Recommendations were made on how to safely and reliably handle SPRB coal: keep areas clean, eliminate ignition sources and detect spontaneous combustion with accumulated SPRB coal dust. These safety steps are designed to protect people, equipment, and enclosures from explosions due to the dangerous spontaneous combustion tendencies of SPRB coal.

Required modifications to the rail delivery system outlined in the study indicate that the current unloading configuration is [redacted]. SPRB coal requirements at this level require the plant to receive approximately [redacted]

[redacted][5]

[5] PacifiCorp also engaged RungePincockMinarco to evaluate the impact from converting to SPRB coal on the Jim Bridger plant's stockpile level and configuration. This study was used to verify the findings of the Burns & McDonnell study.

[redacted].

Table 6 below shows a summary outline of BMcD's total estimated costs, [redacted], associated with the different components referenced in their report.

TABLE 6

Jim Bridger Plant - Burns & McDonnell Estimated Capital Costs		
	[redacted]	[redacted]
Coal Handling	$	[redacted]
Coal Handling Additional	$	[redacted]
Existing Conveyor Scraper Tower with Wind Fence	$	[redacted]
New Loop	$	[redacted]
Power Island Modifications (Unit 1-4)	$	[redacted]
Power Island Modifications (Unit 1-3 Only)	$	[redacted]
Pulverizer Steam Inerting (Units 1-4)	$	[redacted]
Electrical	$	[redacted]
T&D	$	[redacted]
Air Permit	$	[redacted]
TOTAL	**$**	[redacted]
Investment Total w/ Land/ROW Costs	**$**	[redacted]
PacifiCorp Share (Includes AFUDC, Loadings)	**$**	[redacted]

4 FUEL SUPPLY MIX OF PHASE 2 FUELING OPTIONS

The fueling options evaluated during Phase 2 are referenced as 2018 Fuel Plan Options D, E and F, including several variations on those primary options as described below. Please refer to Confidential Appendix B for detailed fueling mix and pricing information for each fueling option considered. The following summaries of the fuel supply mix, including average volumes for the near-term and long-term, for each fueling option evaluated are provided below:

4.1 OPTION D

Option D

- Near-term deliveries (2018-2021)
    - Bridger mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - Black Butte mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
        - [redacted]

- Long-Term deliveries (2022-2037)
    - Bridger mine
        - [redacted]
        - [redacted]
        - [redacted]
        - Total Deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - Black Butte mine
        - [redacted]
        - [redacted]
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - SPRB
        - SPRB deliveries from [redacted]
            - Total deliveries – [redacted] [6]
            - PacifiCorp deliveries – [redacted]

[6] [redacted]

4.2 OPTION D ([redacted])

Option D ([redacted]) is a slight variation on Option D and contemplates [redacted]. Option D ([redacted]) assumes that in [redacted]. Option D ([redacted]) also assumes that the required capital investment is made to allow for the safe delivery and handling of a large volume of SPRB coal at that time.

Option D ([redacted])

- Near-term deliveries (2018-2021)
    - Bridger mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - Black Butte mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
        - [redacted]
- Long-Term deliveries (2022-2037)
    - Bridger mine
        - [redacted]
        - [redacted]
        - [redacted]
        - Total Deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - Black Butte mine
        - [redacted]
        - [redacted]
    - SPRB
        - SPRB deliveries [redacted]
            - Total deliveries – [redacted]
            - PacifiCorp deliveries – [redacted]
            - Assumes plant capital (w/AFUDC and escalation) of [redacted]
                - [redacted]

4.3 Option E

Option E contemplates the closure of the Bridger mine in [redacted], as soon as practicable, and assumes [redacted] of the coal burned thereafter comes from the SPRB. This option assumes a required plant capital investment to safely and reliably deliver and consume large volumes of SPRB coal, approximately [redacted] million tons per year from [redacted]. The estimated investment is [redacted] million with AFUDC and escalation ([redacted] million PacifiCorp share) and includes a rail loop to comply with the railroad standard of unloading a unit train within six hours.

Option E

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - Underground mining operations [redacted]
    - Surface mining operations [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
  - SPRB
    - SPRB deliveries from [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
      - Assumes plant capital (w/AFUDC and escalation) of [redacted]
        - [redacted]

4.4 Option F ([redacted])

Option F ([redacted]) considers the closure of the Bridger surface mining operations in [redacted] and the avoidance of [redacted] million ([redacted] million PacifiCorp share) in development costs required to permit and mine Deadman Wash, further refining Option D.

Option F

- Near-term deliveries (2018-2021)
    - Bridger mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - Black Butte mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
        - [redacted]

- Long-Term deliveries (2022-2037)
    - Bridger mine
        - [redacted]
        - [redacted]
        - [redacted]
        - Total Deliveries – [redacted]
    - Black Butte mine
        - [redacted]
        - [redacted]
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
        - For 2018-2037 time period
            - Total deliveries – [redacted]
            - PacifiCorp deliveries – [redacted]
    - SPRB
        - SPRB deliveries from [redacted]
            - [redacted]
                - [redacted]
            - Total deliveries – [redacted]
            - PacifiCorp deliveries – [redacted]

4.5 OPTION F [redacted])

Option F ([redacted]) is a variation of Option F ([redacted]). The primary difference is that this scenario is based on a Bridger mine plan delivering [redacted] million tons per year in the near-term and assumes Black Butte mine Proposal D, the [redacted] million tons per year proposal, is chosen in the near-term as well.

Option F ([redacted])

- Near-term deliveries (2018-2021)
    - Bridger mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - Black Butte mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]

- Long-Term deliveries (2022-2037)
    - Bridger mine
        - [redacted]
        - Total Deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - Black Butte mine
        - [redacted]
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
        - For 2018-2037 time period
            - Total deliveries – [redacted]
            - PacifiCorp deliveries – [redacted]
    - SPRB
        - SPRB deliveries [redacted]
            - [redacted]
                - [redacted]
            - Total deliveries – [redacted]
            - PacifiCorp deliveries – [redacted]

4.6 Option F ([redacted])

Option F ([redacted]) is a slight variation on Option F and contemplates no longer purchasing Black Butte mine coal after the near-term Coal Supply Agreement ends. Option F ([redacted]) assumes that [redacted] coal replaces Black Butte mine coal in [redacted]. Option F ([redacted]) also assumes that the required capital investment is made to allow for the safe delivery and handling of a [redacted].

Option F ([redacted])

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]
- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - [redacted]
    - [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
  - SPRB
    - SPRB deliveries from [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
      - [redacted]
        - Peak deliveries will occur from 2029 through 2032 – [redacted]

5 PVRR ANALYSIS & RESULTS

Table 7 below shows the results of a PVRR analysis for each fueling option in the 2018 Fuel Plan. The PVRR analysis represents a present value revenue requirement analysis of the total delivered fuel costs and the estimated capital requirements for both the Jim Bridger plant and the Bridger mine, discounted by PacifiCorp's weighted average cost of capital. A total dollar PVRR variance or differential has also been calculated for every fueling option comparing the total PVRR dollar for each fueling option against Option [redacted]. Also included in Table 7 is a financial ranking from 1 to 6 for each of the six fueling options. The Table shows Option [redacted] is ranked [redacted], and Option [redacted] is ranked number [redacted]. The other fueling options fall between these two options. Additional discussion on risk assessment for each fueling option is shown below.

TABLE 7

Jim Bridger Plant Fueling Evaluation (2018-2037) - PacifiCorp Share								
PVRR Summary PAC Portion	PVRR (000's)	PVRR Differential (from lowest $)	Financial Ranking (low to high)	Percent Change (%)	Risk Ranking (low to high)	Project Ranking (Weighted - Financial 60%, Risk, 40%)	Plant Capital (w/AFUDC and escalation, 000's)	Bridger Coal Capital (2018-LOM, escalated, 000's)
[redacted]								

Table 8 presents a risk table for each option and outlines the specific categories that have been considered in the risk evaluation analysis.

TABLE 8

Jim Bridger Plant Fueling Risk Evaluation (2018-2037)							
Options	Risk Ranking (low to high)	Composite Project Risk Score	Incremental Capital	Coal Market	Power Market Volatility	Jim Bridger Plant Environmental Compliance	Deadman Wash Lease Permitting
[redacted]							

The different categories making up the defined risk profile include (1) incremental capital – the risks associated with the total costs of incremental capital expenditures related to each fueling option, (2) coal market – risks associated with adequate coal supplies, as well as coal & transportation price escalation, (3) power market volatility – risks associated with power market price volatility related to changing natural gas prices, the impacts of renewable energy sources impacting GRID dispatch, all which could result in reduced coal consumption, (4) environmental compliance – risks associated with new environmental regulations that could reduce coal generation at the Jim Bridger plant, and (5) Deadman Wash permitting – risks associated with being able to permit the Deadman Wash coal reserve tract in the estimated number of years that would allow the Bridger mine to access the Deadman Wash coal reserve tract and achieve the projected mine cost savings.

For each fueling option under each risk category, a number 1, 2, or 3 has been assigned. Number 1 is designated as "most favorable and low risk." number 2 is "less favorable and moderate risk," and number 3 is "least favorable and high risk." The summation of the assigned risk number for each category for each fueling option, results in an overall "composite project risk" score.

As shown in Table 8, the fueling option with the highest composite risk score is fueling Option [redacted] with a score of [redacted]. Option [redacted] requires incremental capital associated with both the Deadman Wash coal tract as well as new plant capital to support future SPRB coal deliveries. As such, there is added risk for Option [redacted] associated with the capital projects meeting projected cost estimates. Furthermore, there is additional risk associated with the permitting of the Deadman Wash coal reserves in sufficient time which allows for the projected coal production and deliveries from the Bridger mine to be realized. An additional sensitivity was run that determined that for each year of delay in the Deadman Wash permit, the total PVRR amount calculated for Option [redacted] increases by approximately [redacted]. This further closes the PVRR differential gap between Option [redacted] and the other fueling options. The fuel option with the lowest composite risk score, or most favorable score, is Option [redacted]. Under this option there is no incremental capital required and there is very low risk associated with the coal supplies. The other five fueling options have a composite risk score that falls between Option [redacted] and Option [redacted].

All six fuel options are ranked on ascending order from 1 to 6 based upon their composite risk score. Option [redacted] has the most favorable risk option score of [redacted], while Option [redacted] has the worst or highest ranking of [redacted].

From the financial and risk rankings, an overall project ranking has been determined for each fueling option. The overall project weighting is the result of assigning a weighting of [redacted] to the financial ranking and [redacted] to the risk ranking.

As seen in Table 7, in spite of Option [redacted] having the financial ranking of [redacted], it has a risk ranking of [redacted]. This results in an overall project ranking of [redacted]. Option [redacted], has a financial ranking of [redacted], but has the lowest risk ranking of [redacted]. With the weighting between financial and risk rankings, Option [redacted] has the best overall project ranking and is the preferred fueling option. The fueling option with the worst overall project ranking of [redacted] is Option [redacted]. The remaining fueling options are ranked in between Option [redacted] and Option [redacted].[7]

[7] Additional sensitivity analysis was performed on two options. (1) Plant capital was reduced in Option [redacted] for the assumed removal of the rail loop. This change resulted in a reduction to the PVRR differential for Option [redacted] as the savings in capital were offset by increased transportation costs resulting from increased coal unloading times. (2) Option [redacted] was evaluated assuming that approximately [redacted] was purchased in years requiring high volumes of [redacted], deliveries in excess of [redacted]. The [redacted] purchases of roughly [redacted], reduced Black Butte mine volumes in those years. Due to the higher delivered fuel cost of the [redacted], this change resulted in an increase to the PVRR differential for Option [redacted].

6 CONCLUSION

Over the past two years, PacifiCorp has developed a long-term fueling strategy for the Jim Bridger plant to align with the Company's IRP and respond to changing fuel requirements due to market conditions. Mine plans have been run, evaluated and reviewed for the Bridger mine. The various mine options have provided information and direction in determining the optimal total tonnage mix at the Bridger mine for both the underground mine and the surface mine. Different mine closure dates for both the underground mine and the surface mining operations have been considered and evaluated.

Over many months, numerous discussions and negotiations occurred with Lighthouse and the Union Pacific Railroad to develop new near-term coal and transportation agreements. Through these negotiations, new contract rates from different coal regions were obtained. Additionally, long-term indicative rail rates from mines located in the SPRB were provided by the Union Pacific Railroad for coal deliveries to the plant.

In addition to the estimated future coal and transportation rates provided, PacifiCorp also contracted for two consulting studies which provided important information in the PVRR analysis. These two studies were requested to better understand the overall fueling impacts, capital requirements and estimated costs related to a full or partial SPRB fuel switch at the plant. BMcD, a reputable engineering consulting company, completed a comprehensive fuel impact study in June 2017. The study outlined the relevant issues and total estimated costs that would be required to undertake a SPRB coal conversion at the plant.

After considering all of the factors influencing this long-term fueling strategy, six different fueling options were developed and evaluated. Based upon the results of the detailed PVRR analysis, which was further enhanced by utilizing a risk profile, Option [redacted] is the current least-cost, least-risk option and the strategy PacifiCorp is currently pursuing which includes the following:

- [redacted]

While the current analyses shows Option [redacted] as the least-cost, least-risk option, Option [redacted] is the lowest cost option and will continue to be analyzed. PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant taking into consideration both cost and risk of the different options and will change the long-term fuel plan as necessary to provide the least-cost, least-risk long-term fuel supply for the Jim Bridger plant. Furthermore, both Options [redacted] and Option [redacted], allow PacifiCorp to [redacted]

This strategy allows PacifiCorp and the plant to maintain significant fuel supply flexibility related to future decisions impacting the plant's generation and potential unit closures. [redacted]

Confidential Appendix A

Jim Bridger Plant - Generation Summary
Generation Forecast
All Participant Shares - In Millions

Plan Comparison

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Dec-'15 Long Term Fuel Plan																					
MMBtu's Required	[redacted]																				
Forecasted Generation (MWh)																					
2018 Fuel Plan																					
MMBtu's Required																					
Forecasted Generation (MWh)																					
Variance																					
MMBtu's Required																					
Forecasted Generation (MWh)																					
Percent Change (%)																					

REDACTED

CONFIDENTIAL APPENDIX B-OPTION D

Jim Bridger Plant - Option D
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons	[redacted]																				
MMBTUs	[redacted]																				
Dollars	[redacted]																				
$/Ton	[redacted]																				
$/MMBTU	[redacted]																				
Black Butte	[redacted]																				
Tons	[redacted]																				
MMBTU	[redacted]																				
Dollars	[redacted]																				
$/Ton	[redacted]																				
$/MMBTU	[redacted]																				
Regional Coal	[redacted]																				
Tons	[redacted]																				
MMBTU	[redacted]																				
Dollars	[redacted]																				
$/Ton	[redacted]																				
$/MMBTU	[redacted]																				
Powder River Basin	[redacted]																				
Tons	[redacted]																				
MMBTU	[redacted]																				
Dollars	[redacted]																				
$/Ton	[redacted]																				
$/MMBTU	[redacted]																				
Total Coal Received	[redacted]																				
Tons	[redacted]																				
MMBTU	[redacted]																				
Dollars	[redacted]																				
$/Ton	[redacted]																				
$/MMBTU	[redacted]																				
Total Coal Consumed	[redacted]																				
Tons	[redacted]																				
MMBTU	[redacted]																				
Dollars	[redacted]																				
$/Ton	[redacted]																				
$/MMBTU	[redacted]																				

REDACTED

CONFIDENTIAL APPENDIX B-OPTION D ([redacted])

Jim Bridger Plant - Option D ([redacted])
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company																					
Tons	[redacted]																				
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Regional Coal																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Powder River Basin																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

REDACTED

Sierra Club/112
Burgess/34

REDACTED

CONFIDENTIAL APPENDIX B-OPTION E

Jim Bridger Plant - Option E
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons																					
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Regional Coal																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Powder River Basin																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

CONFIDENTIAL APPENDIX B-OPTION F [redacted]

Jim Bridger Plant - Option F [redacted]
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons																					
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
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Regional Coal																					
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Powder River Basin																					
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MMBTU																					
Dollars																					
$/Ton																					
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Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

REDACTED

Sierra Club/112
Burgess/36

CONFIDENTIAL APPENDIX B-OPTION F ([redacted])

Jim Bridger Plant - Option F ([redacted])
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company																					
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REDACTED

Sierra Club/112
Burgess/37

CONFIDENTIAL APPENDIX B-OPTION F ([redacted])

Jim Bridger Plant - Option F ([redacted])
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
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Dollars																					
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$/MMBTU																					

CONFIDENTIAL APPENDIX C-RISK RANKING

Jim Bridger Plant Fueling Risk Evaluation (2018-2037)							
Options	Risk Ranking (low to high)	Composite Project Risk Score	Incremental Capital	Coal Market	Power Market Volatility	Jim Bridger Plant Environmental Compliance	Deadman Wash Lease Permitting
[redacted]							

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

SIERRA CLUB EXHIBIT 113

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment 1.27-3 to PacifiCorp Response to
Sierra Club Data Request 1.27

This exhibit is confidential pursuant to Protective Order 16-128 and is provided in Excel format.

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

SIERRA CLUB EXHIBIT 114

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment 1.10-1 to PacifiCorp Response to Sierra Club Data Request 1.10

This exhibit is confidential pursuant to Protective Order 16-128 and is provided in Excel format.

Docket No. UE 375
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

SIERRA CLUB EXHIBIT 115

Exhibit Accompanying the Opening Testimony of Ed Burgess

Union of Concerned Scientists Panel on Self-Committed Coal in Power Markets

Breakfast Panel on Self-Committed Coal in Power Markets

Hosted by the Union of Concerned Scientists
Moderated by Utility Dive Associate Editor Catherine Morehouse

***Featuring*:**

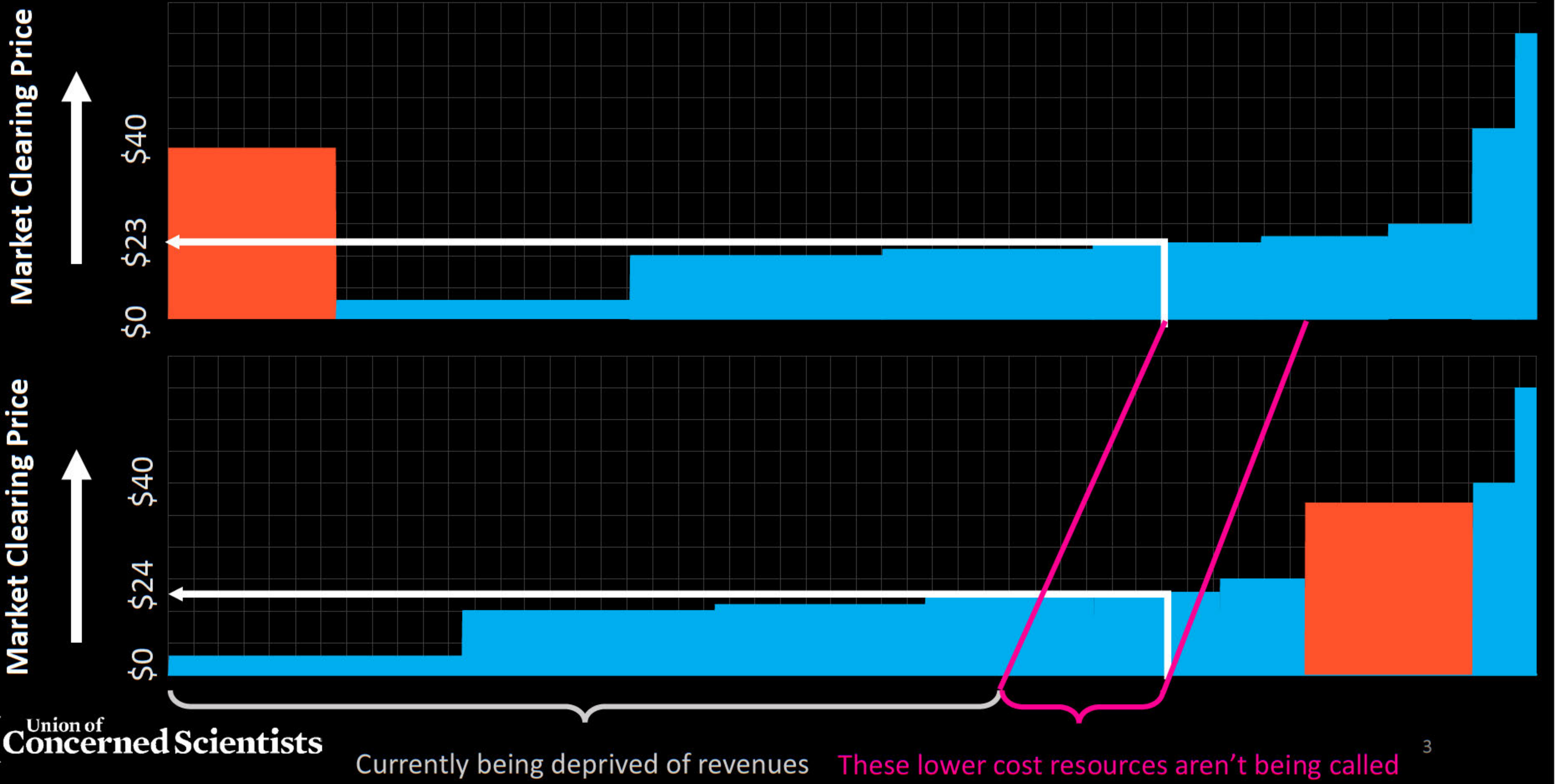
Richard Glick *FERC Commissioner*
Ted Thomas *Arkansas PSC Chairman*
Sarah Freeman *Indiana URC Commissioner*
Annie Levenson-Falk *Minnesota CUB Executive Director*
Joe Daniel *Union of Concerned Scientists Sr. Energy Analyst*

Union of Concerned Scientists

Background

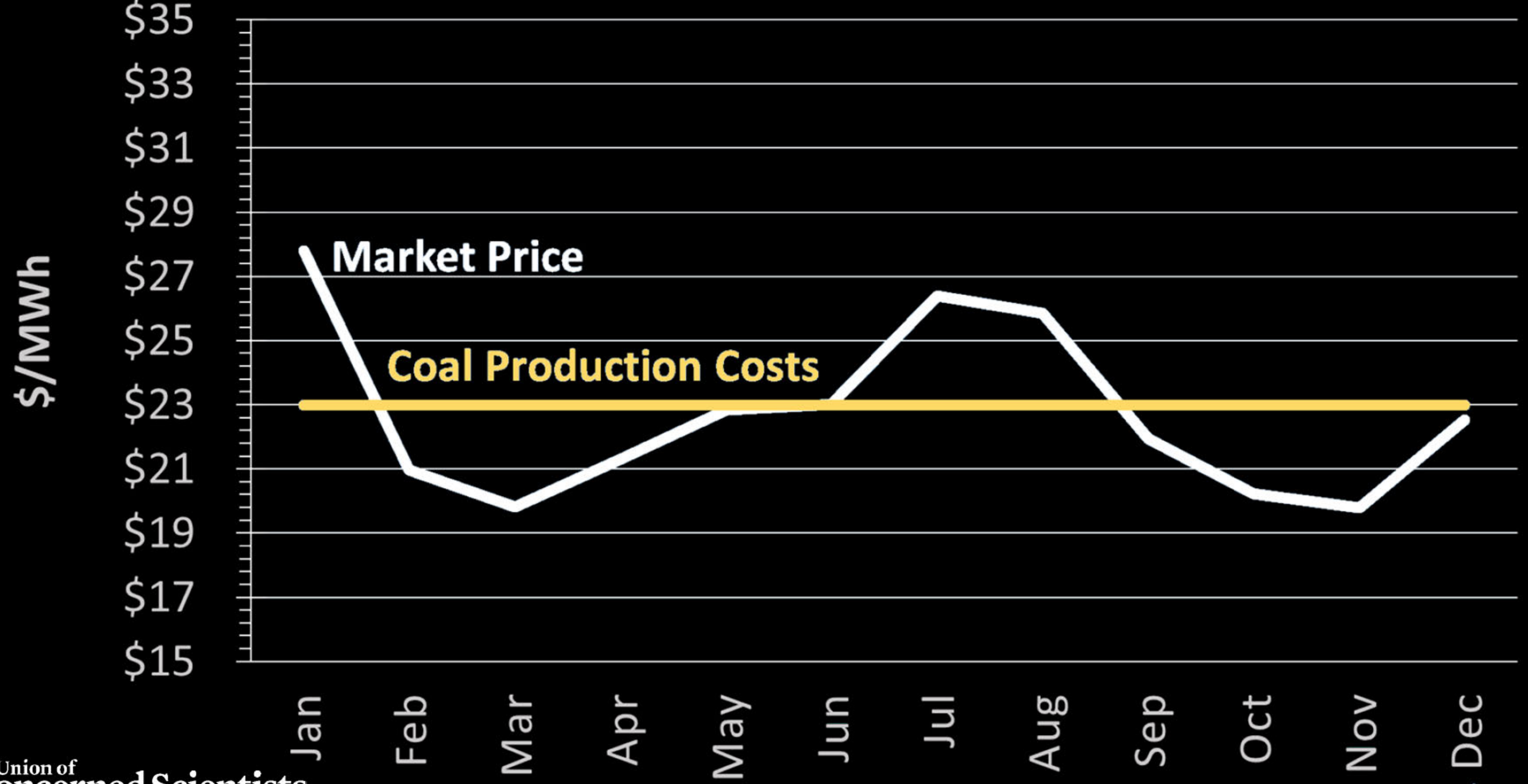
Primer on Self-Committing

Out-of-merit Generation - Visualized



Union of Concerned Scientists

Wholesale Market Prices - Illustrative



Union of Concerned Scientists

History of Research

- Backdoor Subsidies for Coal in SPP – Daniel, J. 2017. Sierra Club
- Dalman Economic Assessment – 2017. Chamber of Commerce
- Half of Coal is on Shaky Ground – Nielson, R. et. al. 2018. BNEF
- Out-of-Merit Coal Generation in Organized Markets– Daniel, J. 2018. UCS
- Playing With Other People's Money – Fisher, J. et. al. 2019 Sierra Club
- Used But How Useful – Daniel, J and S. Sattler. Forthcoming. UCS

Commissioners Taking Notice

- IA: IUB Docket No. RPU-2019-0001 (TF-2019-0017, TF-2019-0018)
- IA: IUB Docket No. RPU-2018-0003
- KS: KCC Docket No. 18-WSEE-328-RTS
- LA: PSC Docket U-34794
- MI: PSC Case No. U-20069
- MI: PSC Case No.: U-20471
- MO: PSC Docket No. EW-2019- 0370
- MN: PSC Docket Nos. E-999/AA-17-492, E-999/ AA-18-373
- MN: PSC Docket No. 19-704
- TX: SOAH Docket No. 473-17-1764 / PUC Docket No. 46449
- WI: PSC Docket No. 5-UR-109
- WI: PSC Docket No. 6690-UR-126

This list is not exhaustive

Analysis and Findings

Preliminary Results for forthcoming report: “Used but how Useful?”

Analytical Approach

MISO

Plexos

2018

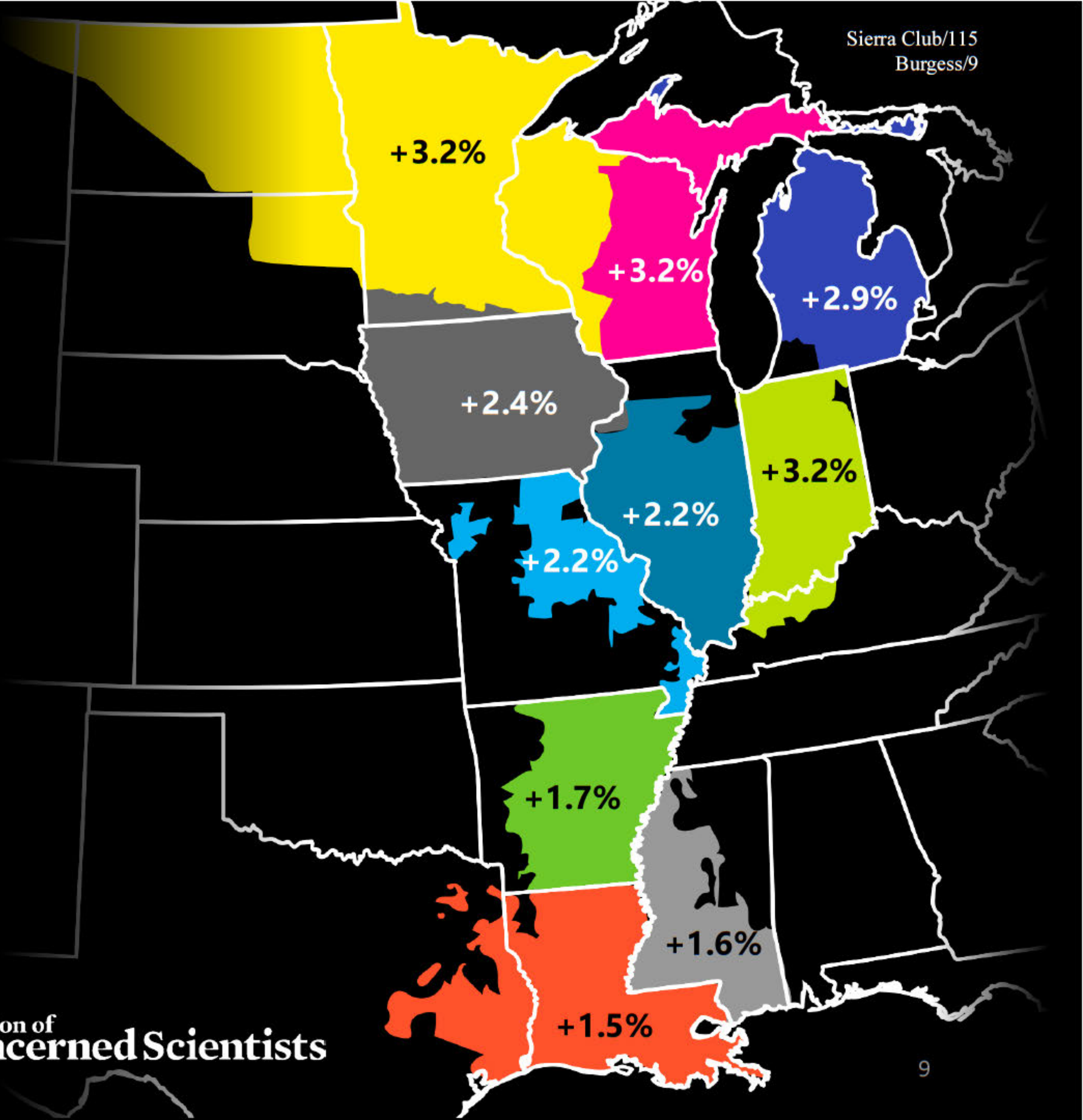
2 Runs

Union of Concerned Scientists

If market resources were dispatched economically, then market prices would increase slightly over status quo.

MISO Avg LMP ↑ 3%

Preliminary Results



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LMP ↑ 3%

Production Costs ↓ 11%

Market Surplus ↑ 64%

Coal Generation ↓ 19%

Preliminary Results

Dispatching resources economically produces a more healthy and efficient market:

Customer costs ↓

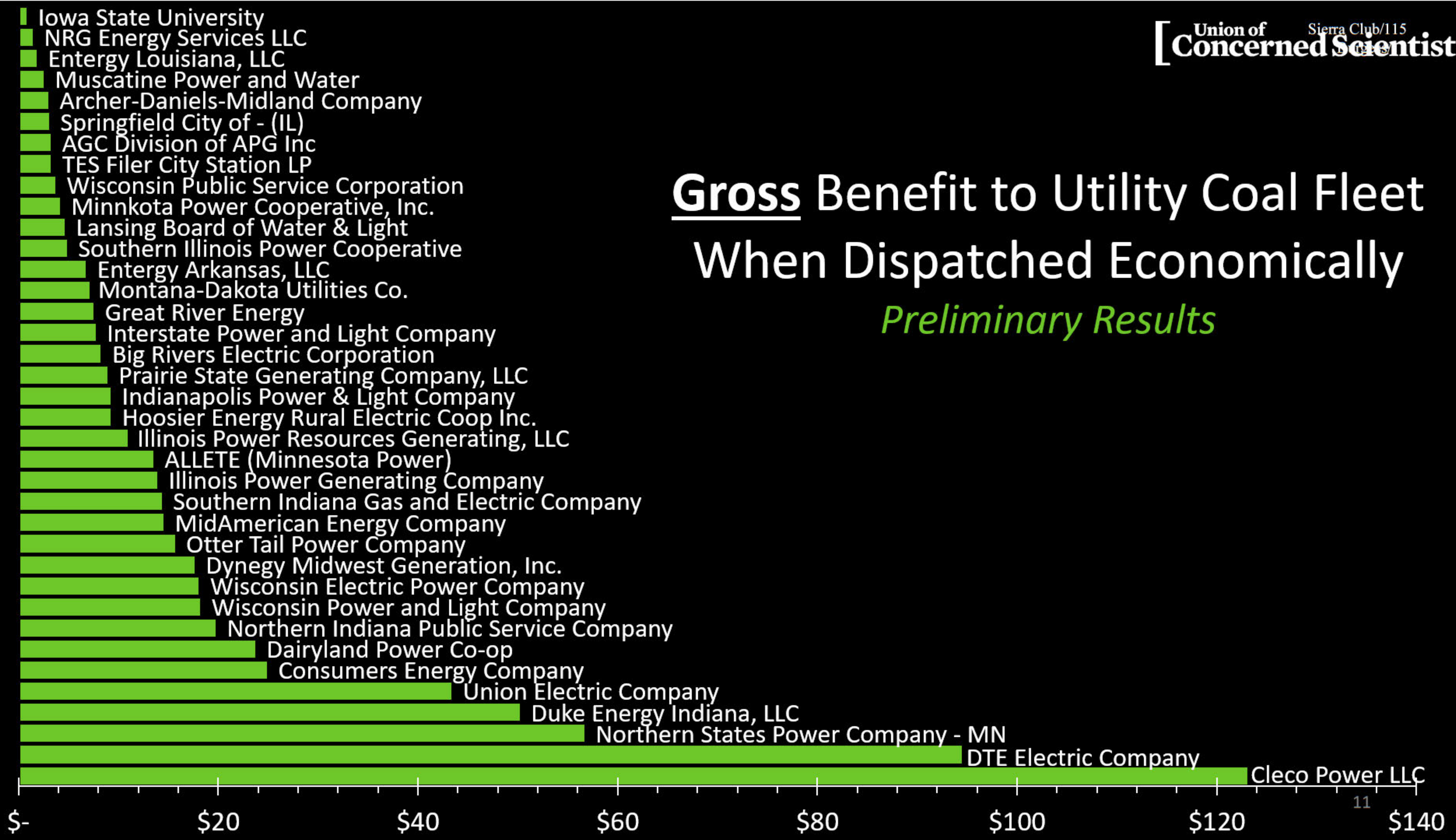
&

Market profits ↑

Union of Concerned Scientists

Gross Benefit to Utility Coal Fleet When Dispatched Economically

Preliminary Results



Conversation moderated by Catherine Morehouse Utility Dive

Comm'r. Rich Glick
FERC

Comm'r. Sarah Freeman
IN URC

Annie Levenson-Falk
MN CUB

Chmn. Ted Thomas
AR PSC

Joe Daniel
UCS

Union of Concerned Scientists