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May 15, 2020

***Via Electronic Filing and US Mail***

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

**RE: Docket No. UE 375 – In the Matter of PACIFICORP, dba PACIFIC POWER, 2021 Transition Adjustment Mechanism.**

Enclosed for filing are the following exhibits:

Exhibit 100 to 101: Gibbens

Exhibit 200 to 205: Enright

- Exhibit 200: confidential pages: 6-8, 13-17, 21-22, 29-30, 33, 35-36 40-41, 43, 46, 50, 52 and 53
- Exhibit 203 is confidential
- Exhibit 201, 204 and
- Exhibit 205 is in electronic format

Exhibit 300 to 302: Soldavini

- Exhibit 300: confidential pages: 6-7 and 9 -13
  Highly confidential pages: 14 and 15
- Exhibit 301 and 302

Exhibit 400 to 403: Zarate

- Exhibit 400: confidential pages: 2, 6, 7, 10 & 11
- Exhibit 401 and 402
- Exhibit 403 is confidential with 2 spreadsheet

Confidential and Highly-confidential exhibits will be mailed to parties who have signed Protective and Modified Protective Order in UE 375.

/s/ Kay Barnes
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CERTIFICATE OF SERVICE

UE 375

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

Dated this 15th day of May, 2020 at Salem, Oregon

Kay Barnes

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UE 375

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CASE: UE 375
WITNESS: SCOTT GIBBENS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 100

# Opening Testimony

**May 15, 2020**

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

A. My name is Scott Gibbens.  I am a Senior Economist employed in the Energy Finance and Audit Division of the Public Utility Commission of Oregon (OPUC).My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

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

A. My witness qualification statement is found in Exhibit Staff/101.

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

A. I discuss the 2021 TAM filing and Staff's analysis of the issues. Specifically, I will discuss Staff's review of and recommended Commission action regarding: load forecast and allocation factors, wind capacity factors and PTC forecasts, the official Forward Price Curve (OFPC) scalar methodology, and the Nodal Pricing Model.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## 2021 TAM BACKGROUND

**Q. Please summarize PacifiCorp's 2020 TAM filing.**

A. On a system basis, the Company's initial filing requested a 2020 Net Power Cost (NPC) of $1,401,677,191, which represents a decrease of approximately $40.2 million compared to the final 2020 NPC.[1] The reduction in Total NPC is further increased by an approximately $151.4 million increase in forecast production tax credit (PTC) benefits compared to the previous year.[2] The net adjustment of the 2021 TAM is a $193 million decrease on a total Company basis.[3]

**Q. What is the effect on an Oregon basis?**

A. On an Oregon basis, the 2021 TAM of approximately $292 million is lower than the 2020 TAM of $344.6 million.[4] When accounting for load changes this represents a 3.7 percent decrease to overall rates on a net basis.[5]

**Q. Did PacifiCorp propose any changes from its methodology in the 2021 TAM?**

A. Yes. PacifiCorp proposes to:

1. Update scalar methodology for the OFPC.
2. Integrate the flexible reserve study from the 2019 IRP.
3. Update the EIM benefits model.

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[1] PAC/101, Webb/1 line 38.
[2] *Ibid.* line 41.
[3] *Ibid.* line 42.
[4] *Ibid*.
[5] PAC/100, Webb/3 line 7.

**Q. What topics will Staff's opening testimony address?**

A. Staff discusses the following issues in our opening round of testimony:

(Staff/100 - Gibbens)

1. Load Forecast and Allocation
2. Wind Capacity Factor Forecasts
3. Nodal Pricing Model
4. OFPC Scalar Methodology

(Staff/200 - Soldavini)

5. Other Revenues
6. Jim Bridger Fuel Plan and BCC
7. Coal Contracts
8. Company Supply Service Access Charge
9. Naughton 3 Gas Conversion

(Staff/300 - Enright)

10. Economic Cycling
11. Wholesale Power Transactions
12. Day Ahead/Real Time Adjustment
13. Western EIM Benefits

(Staff/400 - Zarate)

14. Standard Inputs
15. Wheeling Costs
16. PURPA

## ISSUE 1, LOAD FORECAST AND ALLOCATION

**Q. How does PacifiCorp's Load Forecast in the 2020 TAM compare to last year's 2019 TAM Load Forecast?**

A. Oregon's load is estimated to decrease by 1 percent, or 158 GWh, from 2020 to 2021. Oregon load is forecasted to be approximately 14,968 GWh in 2021. Due to forecasted load reduction, PacifiCorp anticipates $3.4 million less than expected will be collected in NPC based on rates approved in the 2020 TAM, and has included this amount in the overall rate change for the 2021 TAM, as an increase to NPC.[6]

**Q. Has the Company updated its load forecast methodology in this TAM compared to the 2020 TAM?**

A. Yes. This year, the Company developed a post-model adjustment to the residential and commercial sales forecasts that estimates the projected transportation electrification levels going forward. The Company also incorporated a LED lighting adoption curve into its street lighting forecast.

**Q. How did Staff analyze this issue?**

A. Due to the Company filing a GRC concurrent with this year's TAM, Staff is analyzing the Company's load forecast methodology in that docket. This approach limits the number of duplicate issues in the two dockets and allows Staff to perform a deeper level of analysis. Further, the impacts of load forecast on the power costs and a general rate case are different. In power costs, load

[6] Staff notes that PAC/100, Webb/3 line 16-18 states the opposite (that Oregon load grew), however based on the Company's workpapers and Exhibit PAC/101, Staff believes this statement is incorrect and the Company's Oregon load forecast fell in 2021.

increases tend to have offsetting effects where the variable costs increase but the recovery in rates does as well. In a general rate case, the majority of the costs are fixed, so an under-forecast in that scenario would result in over-recovery through rates without offsetting impacts to the costs themselves. Staff has reviewed the load forecast and at this time find it reasonable. Staff reserves the right to make alternate recommendations in the GRC given a greater depth of review.

**Q. Does Staff propose an adjustment to Load Forecasting?**

A. No, at this time. Staff recommends that the Company incorporate any adjustments or changes to the load forecast made in UE 374 if there is sufficient time to implement them in this docket.

## ISSUE 2, WIND CAPACITY FACTOR FORECASTS

**Q. Please provide a background for this issue.**

A. In UE 339, PacifiCorp proposed to change the forecast methodology for the wind farms owned by the Company. Specifically, PacifiCorp proposed to change a fixed capacity factor for the life of the asset based on the generation forecasts used to determine the prudence of the project to a forecast based on a rolling 48 months of historical generation.[7] Ultimately, parties settled on a 50/50 methodology which utilizes fifty percent historical actuals, and fifty percent original P50 forecast, for a one-year basis.[8] In UE 356, the parties agreed to a three-pronged approach that ensured customers received the benefits of economic investments related to the EV 2020 repowering projects and New Wind projects. For non-repowered wind projects, the same 50/50 methodology is utilized. For repowered wind facilities, the economic analysis from February 2018 will be used to calculate the capacity factors. For all new wind facilities, the economic analysis used to justify the investment will be used in the TAM. As part of the agreement, no party will propose any changes to the wind capacity factors until the 2025 TAM.

**Q. Has the Company complied with the 2020 stipulated methodology?**

A. Yes. Staff reviewed the Company's workpapers and found that the Company has properly included the wind capacity factors from the varying sources based on the vintage of the wind project. This ensures that the customers receive the

[7] PAC/100, Wilding/34.
[8] Order 18-421 at 4.

benefits they were expecting for the next five years at a minimum. Staff notes that due to the increase in the level of wind generation, net power costs are over $150 million less than they otherwise would have been.

## ISSUE 3, NODAL PRICING MODEL

**Q. What is a nodal pricing model (NPM)?**

A. Nodal Pricing is a way of finding separate equilibrium prices for a vast number of locations within a given system. The model uses supply, demand, and transmission constraints to calculate the locational marginal price (LMP) at nodes on the system. Each node represents the physical location on the transmission system where energy is injected by generators or withdrawn by loads. Under a nodal pricing model, each of PacifiCorp's six states would have its own metered load boundaries (and associated price) and a day-ahead locational marginal price associated with each of PacifiCorp resources. Due to different states within PacifiCorp's service territory pursuing different energy policies, a way to separately track each state's power costs based on load and generator was necessary. Accordingly, PacifiCorp sought a third party that would operate a dispatch engine to optimize PacifiCorp's day-ahead resources and create transparent nodal pricing to enable precise power cost tracking.

**Q. Who is the third-party that PacifiCorp has chosen to operate its NPM?**

A. PacifiCorp has contracted with the California ISO (CAISO) to implement a NPM. The service will begin on January 1, 2021 and is expected to be utilized to track power costs starting in 2024.

**Q. Why did PacifiCorp choose CAISO to run its NPM?**

A. Many of the optimization systems necessary to run a nodal pricing model already exist in CAISO's "Total Market Model", which creates an LMP at the many different nodes and market hubs within its market. Further PacifiCorp has already integrated much of its system to operate within the Western EIM which is also operated by CAISO. The NPM will use the same tool, network model, and input data as the EIM and any potential enhanced day-ahead market.

**Q. How will the NPM be used?**

A. Beginning in 2021, the NPM will be used to dispatch PacifiCorp's system on a day-ahead basis. Once the interim period of the 2020 multi-state protocol is over, PacifiCorp expects to utilize the NPM to track power costs beginning in 2024. PacifiCorp is currently reviewing options for forecasting power costs using a NPM in order to match the forecasts and actuals once the switch is made in 2024.

**Q. Why is Staff raising this issue now?**

A. Although the NPM will not be used to track power costs until 2024, customers will begin paying for the NPM next year.[9] This includes an $8.4 million annual service fee paid to CAISO to perform the nodal pricing model service. Apart from allowing the Company to better track costs and assign them on a more granular level, the model also represents a new dispatch algorithm which will be used starting next year. Staff believes that this more complex dispatch system, which is better integrated with CAISO's EIM, will provide cost savings through a more optimal solution to generation dispatch.

**Q. Why does a nodal dispatch provide cost savings?**

[9] PacifiCorp will use the CAISO NPM to track power costs, and is attempting to identify another appropriate nodal based model to forecast power costs.

A. Staff continues to learn about the differences between the Company's current dispatch model and the NPM as it relates to operational savings (as opposed to modeling changes) and invites the Company to provide the Commission with a more in-depth discussion. It is Staff's current understanding that PacifiCorp's current operational dispatch is based on a zonal model, which defines areas of limited transmission constraints and connects the zones via transmission constraints between them. Within each zone, the generation-weighted averages contributing to the constraints between each zone are the same. Under a nodal model dispatch, each individual generator is assigned a separate contribution to transmission constraints. This leads to a better-informed model that can optimize to a higher level of precision. In 2010, ERCOT changed from zonal to nodal dispatch and estimated consumer savings at $5.6 billion over the following 10 years.[10]

**Q. What is Staff's recommended adjustment for this issue?**

A. Although the tracking and forecasting of costs using a nodal pricing model are not set to ensue until 2024 per the 2020 protocol, Staff believes that the efficiency gains as a result of the new dispatch logic should be passed onto customers in this year's TAM. Staff views this adjustment similar to the Company's participation in the EIM and the resulting benefit adjustment which results. Customers are currently paying for a new modeling approach which is expected to provide some cost savings, as a result, the 2021 forecast should include an estimate of the expected impact on power costs. Staff does not

[10] http://www.ercot.com/news/releases/show/349

have an estimated adjustment of the impact at this time but will work with the Company and intervenors to arrive at a reasonable number.

## ISSUE 4, OFPC SCALAR METHODOLOGY

**Q. What is the Official Forward Price Curve?**

A. In the TAM, the Official Forward Price Curve (OFPC) OFPC is the market price fed into GRID on an hourly basis by which GRID optimizes the generation portfolio and makes necessary market purchases and economic market sales. The OFPC starts as an average monthly price, which gets shaped by the hour on a, generally speaking, weekly basis. So apart from holidays, every week within each month will look identical. The scalars shape the monthly price by applying a different factor to each hour in a month for a given day type. A factor of 1.1 would mean that prices are 10% higher than average for that particular hour in the week (average price X hourly factor). The monthly average price in GRID remains the same as the OFPC monthly price but each hour in a day type will be higher or lower to reflect normal prices.

**Q. How is the Company proposing to change the scalar methodology?**

A. Prior to the 2020 TAM, the Company scaled the OFPC by applying factors based on the average value for five years of historical hourly prices from PowerDex.[11] Each day type factor was the result of the average of that day type's hourly price over the five years divided by the monthly average price.

In the 2020 TAM. the Company proposed to use a single year of day-ahead hourly market prices at the California-Oregon Border (COB) and Palo

[11] UE 356 PAC/100, Wilding/19.

Verde (PV) markets provided by CAISO.[12] The process is similar, but instead of five consecutive years, the Company would only use a single year.

In response to Staff and Intervenor concerns regarding the normalization of the scalars raised in the 2020 TAM, PacifiCorp has proposed to use two years' worth of data from CAISO, which it would average to come up with the hourly scalars.

**Q. Does Staff support this change?**

A. Yes, Staff views the change from a single year to two years as an improvement. Staff's recommendation following the Company's proposal to change the OFPC scalars in last year's TAM was to utilize at least two years of CAISO data.[13] In making the change to incorporate two years to calculate the scalars, the Company has reduced the one of Staff's two concerns regarding the new methodology. Two years will produce a more normalized forecast of prices, more robust against non-normal events which may occur in a single year.

**Q. What was Staff's other concern?**

A. Staff's other concern was regarding the use of the California-Oregon Border (COB) market hub as opposed to the Mid-C market. In looking at the Company's historical trading volumes, it is apparent that the Company transacts much more often at Mid-C than at the COB market. Although these markets are somewhat correlated in terms of price, they are not

[12] *Ibid*.
[13] UE 356, Staff/100, Gibbens/33 at line 5.

perfectly correlated. The use of the COB market is simply due to the fact that CAISO does not report Mid-C day-ahead market prices like it does for COB.

**Q. Has the Company accounted for this concern in this year's filing?**

A. No. As noted on the record in UE 356, Staff was not able to find a market index which would serve the same purpose and was publicly available like the CAISO data. The Company has chosen to continue the use of the COB market in lieu of Mid-C.

**Q. Does Staff have any recommended adjustments or changes to the methodology?**

A. No. Not at this time. Staff notes that the use of two years of data was the minimum requested amount in order to mitigate the normalization concern. Staff will continue to monitor the impact of single large events on the scalars. Staff recommends that in the following TAMs, the Company review the appropriate balance of normalization and realistic values as more data becomes available in the future. Staff further recommends that the Company continue to look for more appropriate market hub indices as inputs to the scalar methodology.

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

A. Yes.

CASE: UE 375
WITNESS: SCOTT GIBBENS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 101

# Witness Qualifications Statement

**May 15, 2020**

**WITNESS QUALIFICATION STATEMENT**

| | |
|---|---|
| NAME: | Scott Gibbens |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Economist<br>Energy Rates, Finance and Audit |
| ADDRESS: | 201 High St. SE Ste. 100<br>Salem, OR 97301-3612 |
| EDUCATION: | Bachelor of Science, Economics, University of Oregon<br>Masters of Science, Economics, University of Oregon |
| EXPERIENCE: | I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management. |

CASE: UE 375
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 200

## Opening Testimony

**May 15, 2020**

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

A. My name is Moya Enright. I am a Senior Utility and Energy Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (Commission). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

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

A. My witness qualification statement is found in exhibit Staff/201.

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

A. I discuss the PacifiCorp (PAC or Company) 2021 TAM filing and Staff's review of and recommended Commission action regarding: Economic Shutdowns, Wholesale Transactions, and the Day Ahead/Real Time (DA-RT) Adder. In addition to this, I will explain Staff's review of several issues of interest regarding the Company's participation in the Western Energy Imbalance Market (EIM) benefits, including the Company's forecasted Inter-Regional Transfer Benefits, Green House Gas (GHG) Benefits, and Flexible Reserve Benefits.

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

A. Yes. I prepared the following Staff Exhibits:

- Staff/201: Witness Qualification Statement
- Staff/202: Referenced news articles and documents.
- Staff/203: PacifiCorp's confidential responses to Staff data request (DR) Nos. 88 and 99, and PacifiCorp's response to ALJ bench request 1.

- Staff/204: PacifiCorp's responses to Staff DR Nos. 8, 10, 11, 12, 13, 16, 18, 19, 22, 24, 27, 28, 34, 41, 61, 64, 68, 86 (redacted), 93, 105, and PacifiCorp's response to Sierra Club DR 1.25..
- Staff/205: Staff workpapers, confidential electronic exhibit.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:



**Q. Please summarize your recommendations and adjustments.**

A. Staff's recommendations and adjustments are as follows:

1. Economic Shutdowns:
    a. Require the Company to submit a quarterly report to the Commission detailing any instances of actual uneconomic operation of its coal plants, specifically, when production costs are above the market price for energy.
    b. Remove the "must run" condition in GRID from all coal units, for every month of the year.
    c. Require the Company report on its engagement with its co-owners regarding the potential for economic shutdowns, submitting a progress report to the Commission by January 1, 2021.

d. Remove the four start-up limit on economic shutdowns in the current TAM modeling, and require any replacement start-up limit to be informed by the study detailed in subsection (e) of Staff's recommendation.

e. Require the Company to conduct a comprehensive study into the non-fuel costs and savings of economic shutdowns by January 1, 2021.

2. Wholesale Transactions

No adjustment recommended.

3. EIM Benefit Forecasting

a. Reject PacifiCorp's calculation of actual EIM benefits in 2015 and 2016.

b. Reject PacifiCorp's calculation of actual GHG benefits.

c. Increase the GHG Benefit forecast by five percent plus inflation for each twelve month period, and proportionately for periods of less than one year.

d. Update the IRP modeled flexible reserve benefit with data from the most recent twelve months available.

e. Require the Company to request copies of the CAISO benefits calculations from CAISO on a quarterly basis beginning with quarter one 2019, and require that it maintain this data, making it available for consideration by Staff in future filings.

4. DA-RT Adder

Require the Company to hold a workshop with Staff and intervenors prior to April 1, 2021, to investigate how the adoption of the AURORA model in the 2022 TAM can address the deficiencies in GRID which caused the DA-RT adder to be adopted.

## ISSUE 1, ECONOMIC SHUTDOWNS (ECONOMIC CYCLING)

**Q. Please provide an overview of your testimony regarding economic shutdowns.**

A. Staff's testimony is structured as follows:

- Background on economic shutdowns, overview of the costs and benefits, and discussion of how they are modeled in the TAM.
- Description of Staff's analysis, and discussion of Staff's concerns.
- Summary of Staff recommendations on economic shutdowns.

**Q. Please provide background for this issue.**

A. Changing market conditions, such as when market prices are lower than the marginal cost of operating the coal unit, have resulted in some PacifiCorp coal units becoming un-economic for extended periods. This has become more common in recent years, as renewable generation becomes more competitive than coal generation.[1] In these cases, PacifiCorp has managed to reduce power costs through economic shutdowns of coal plants.

In addition to the financial benefits of economic shutdowns, environmental benefits also accrue when coal generation is replaced by lower emitting alternatives.[2]

[1] See Exhibit 202. "The Coal Cost Crossover: 74% Of US Coal Plants Now More Expensive Than New Renewables, 86% By 2025", Forbes, March 26, 2019.

[2] See Exhibit 202. "Xcel Minnesota: Running coal seasonally will save customers millions, reduce emissions", Utility Dive, January 8, 2020.

**Q. Is this unique to PacifiCorp?**

A. No. This is not unique to PacifiCorp, but mirrors the experiences of many other coal generators across the country in recent years, which are also opting for seasonal shutdowns[3] of coal plant that have become uneconomic to run.[4]

Xcel Energy (Xcel) for example, asked regulators in Minnesota in early 2020 to approve the seasonal dispatch of two of its plants, representing 31 percent of the company's capacity. Xcel expects to save "anywhere from $8.5 million to $28.5 million annually on fuel costs by operating the plant based on market signals during the non-peak seasons, unless they are needed for reliability." Other expected benefits to its approach include reducing emissions, and continuing to study how this type of operation affects the rest of their system to ensure reliability. In addition to the fuel costs mentioned above, over a nine-year period Xcel expects this approach to save a further $18.4 million in total operation and maintenance costs, and $27 million in capital costs.[5]

Another example is Dolet Hills coal generator in Louisiana, which in late 2018 was announced to be transitioning from generating electricity year-

[3] Staff is using the umbrella term "economic shutdown" to refer to shutdowns of units for economic reasons. The specific term "seasonal shutdown" is here, as this most accurately reflects the coal plant shutdowns modeled by the Company. The term "economic cycling", which was used in previous filings, is a term better suited to the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** carried out by PacifiCorp, demonstrated in the confidential electronic attachment to PacifiCorp's response to Staff DR 103.

[4] See Exhibit 202. "Texas muni to shut Gibbons Creek coal plant for most of the year", Utility Dive, July 24, 2017.

[5] See Exhibit 202. "Xcel Minnesota: Running coal seasonally will save customers millions, reduce emissions", Utility Dive, January 8, 2020.

round to seasonal, during the hottest months when demand is highest, from June to September, saving customers of CLECO and SWEPCO utilities $85 million.[6]

**Q. What financial benefits have been forecasted from economic shutdowns in the Company's current and previous TAM filings?**

A. PacifiCorp modeled the economic shutdown of coal units both in the 2019 and 2020 TAM filings. The forecasted cost savings are as shown in Figure 1.[7] [8] [9]

*Figure 1 - GRID-modeled financial benefits and hours of economic coal shutdowns (confidential)*

**[BEGIN CONFIDENTIAL]**

| [redacted] | [redacted] | [redacted] |
|---|---|---|
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |

**[END CONFIDENTIAL]** Staff notes that the decrease in forecasted benefits from economic shutdowns in the 2021 TAM, when compared with previous TAM filings, is driven in part by the permanent closure of Cholla 4 at the end of 2020.[10]

6 See Exhibit 202. "SWEPCO announces coal mine layoffs for 2019", KSLA News, December 4, 2018.
7 UE 339 - PAC/100, Wilding/36.
8 See the confidential electronic attachment to PacifiCorp's response to Staff DR 5.
9 UE 356 - PAC/100, Wilding/17.
10 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** by PacifiCorp in recent years. See the confidential electronic attachment to PacifiCorp's response to Staff DR 5.

PacifiCorp is modeling economic shutdowns for just two of its 23 coal generators in the 2021 TAM.[11]

**Q. What other benefits or costs arise from economic shutdowns?**

A. When modeling economic shutdowns, GRID accounts for the economic value of the shutdown, while incorporating the minimum up times, minimum down times, and startup costs. This approach has the potential to miss other benefits or costs of economic shutdowns.

For example, repeated short-term economic shutdowns can increase O&M cost, as startups and shutdowns increase wear and tear on the machinery. Conversely, in the case of seasonal shutdowns where several months of planned use does not occur, larger O&M projects such as major outages can be delayed, driving O&M costs lower.

Finally, several of the additional benefits of economic shutdowns, such as its contribution to the Company meeting Clean Air Act rules and reducing carbon emissions, are not captured in GRID's decision-making process. These benefits can bring significant value to customers, for instance in 2019 PacifiCorp avoided spending over $300 million on new pollution controls at its Jim Bridger plant to meet its regional haze targets in Wyoming, by making operational changes at the plant.[12]

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[11] See Exhibit 204. PacifiCorp's response to Sierra Club DR 1.25.

[12] See Exhibit 202. "PacifiCorp to Reduce Jim Bridger Output to Meet Wyoming Haze Plan", Clearing Up, September 6, 2019. Note that this article incorrectly states that PacifiCorp will "limit the capacity factor for all four coal-fired units at Bridger to 76.3 percent". Having clarified this matter with the Company, Staff notes that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

**Q. How does PacifiCorp model economic shutdowns in GRID?**

A. Normally, all coal units are marked as “must run” in GRID.[13] Beginning with the 2019 TAM; however, PacifiCorp has allowed GRID to model whether it is economic to shut down a plant by removing the “must run” constraint from certain coal units, when a number of restrictive conditions are met.[14]

Staff finds the use of a “must run” constraint for coal units in GRID to be concerning. GRID is a production cost model, which is designed to simulate the operation of the Company’s power system on an hourly basis, using the most economic resource available. The use of a “must run” condition inhibits GRID’s economic decision-making,[15] and may lead to uneconomic results. This is similar to how recent studies have shown that self-scheduling units in power markets often run at a loss.[16]

Staff recognizes that this “must-run” rule may facilitate the modeling of take-or-pay coal contracts, however Staff does not accept that a blanket “must run” rule for coal generation is an appropriate solution.

**Q. Is the Company’s model likely to change in the near future?**

A. Yes. The Company has informed Staff of its intention to begin using the AURORA model to forecast power costs in the 2022 TAM filing.

[13] See Exhibit 204. PacifiCorp’s response to Sierra Club DR 1.25, which states ““All coal units, except Hunter Unit 1 and Hunter Unit 2, during the period of February 1 and May 31 are subject to a must-run constraint.”

[14] The restrictions are described in detail in page 13.

[15] See UE 339, PAC/100, Wilding/35, lines 15 – 16.

[16] See Exhibit 202. “The Billion-Dollar Coal Bailout Nobody Is Talking About. Self-Committing In Power Markets”, Forbes, May 28, 2019.

Staff regards this change as a unique opportunity for the Company and its stakeholders to collaborate to ensure that economic shutdowns are being modeled in power cost forecasts in the most appropriate way, while still accounting for constraints such as take-or-pay provisions.

**Q. How are the Company's actual operations and its GRID modeled forecast intertwined?**

A. Oregon power cost rates are set through the Transition Adjustment Mechanism, a forecast of power prices prepared in advance of the calendar year, while any deviations from forecast go through the Power Cost Adjustment Tariff (PCAM).

Both aspects of power cost filings are critically important. In the case of the TAM, the most economical way of running the system is modeled. The PCAM ensures that the Company has performed in a cost-effective way, by holding it to the forecast.

Each filing informs the other. The PCAM filing informs the TAM forecast about actual operations; while the TAM filing informs the Company's actual operations by providing financial targets for their performance.

**Q. Please describe Staff's analysis of this issue.**

A. Staff's research included issuing substantial discovery, including a total of 13 data requests relating to this topic. Staff also researched the changing landscape for coal generators across the US.

Staff's analysis included an in-depth analysis of the Company's actual coal and gas generator economic shutdowns since 2016, querying analysis carried out by the Company in optimizing its modeling of economic shutdowns, and reviewing economic shutdown decision-making in actual operations.

**Q. What concerns did Staff have about PacifiCorp's modeling of economic shutdowns?**

A. Staff addressed the following concerns:

1) The importance of forecasting efficient economic operations in the TAM.

2) Unnecessary restrictions are imposed in the forecasting model.

3) Non-fuel financial benefits of economic shutdowns are not considered.

4) Missed opportunities for economic shutdowns linked to planned outages.

**Q. Staff's first concern relates to the importance of forecasting efficient economic operations in the TAM. Please explain how this is relevant to the forecasting of economic shutdowns.**

A. As described above, both the TAM and AUT filings are critically important. Actual operations inform the TAM forecast, while the TAM provides a financial target, reflecting economic operations, which the Company must perform to.

In the case of coal generation and economic shutdowns, there has been increasing evidence of utilities defaulting to coal generation without regard for the economics of doing so. Regulators across the country are beginning to scrutinize the scheduling of coal generation, as wholesale markets increase transparency and shine a light on non-economic decision-making.

For example, a bill proposed in Minnesota in early 2020 would require utilities to analyze the economic and environmental costs and benefits of seasonal shutdowns of their nonrenewable energy sources.17 This follows a decision by Minnesota's Public Utilities Commission to request data from their investor-owned utilities on the practice of "self-committing" and "self-scheduling" generating units in the Midcontinent Independent System Operator (MISO) grid. A similar case has also been opened by the Public Service Commission in Missouri to investigate whether the practice is benefiting the state's ratepayers.[18] [19]

**Q. What is Staff's recommendation on this matter?**

A. Staff recommends the Commission require the Company to submit a report to the Commission on a quarterly basis, which provides details of any instances of uneconomic operations at its coal plant, specifically, when production costs are above the market price for energy. The exact contents, format, and timing of this report would be agreed by the Company, Staff, and intervenors.

**Q. Staff's second concern relates to the unnecessary restrictions which the Company's places on the modeling of economic shutdowns. Please describe these restrictions, and why this is significant.**

A. PacifiCorp prevents GRID from modeling economic shutdowns by using a "must run" constraint for all of its coal units, unless the following strict conditions are met:[20]

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[17] See Exhibit 202. "'Coal holiday bill' would make seasonal shutdowns possible", Minnesota House of Representatives, February 18, 2020.

[18] See Exhibit 202. "Are old Midwest coal plants pushing renewables offline?" E&E News, June 11, 2019.

[19] See Exhibit 202. "Missouri regulators vow to keep closer eye on power plant self-scheduling", Energy News, September 17, 2019.

[20] See Exhibit 204. PacifiCorp's response to Staff data request 12.

*A) "Economic Cycling Period"*: GRID is permitted to model economic shutdowns during a four-month window only, from February 1 to May 31.

*B) Non-EIM participating units*: Only non-EIM participating units may be considered by GRID for economic shutdowns.

*C) Majority owned units*: Only majority owned units are made available for economic shutdowns.

*D) Limited number of startups:* The number of startups during the entire cycling period is limited to no more than four.[21]

**Q. Please explain Staff's concerns regarding the Company's "Economic Cycling Period."**

A. The Company's model permits economic shutdowns during a four-month window, which runs from February 1 through May 31. It enforces this by assigning a "must run" setting to all other coal units in GRID. The Company states that this four-month period is informed by historic instances of economic shutdowns, which often occur in Spring, being driven by seasonally lower loads, mild weather, lower market prices, and hydro and solar conditions.[22]

*Figure 2 - Months in which economic shutdowns have occurred (confidential)*

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

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[21] See UE 356, PAC/400, Wilding/33.

[22] See Exhibit 204, PacifiCorp's response to Staff DR 8.

In spite of this, data provided in response to Staff discovery shows that in the past four years, economic shutdowns have historically occurred on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** months of the year. This data is summarized in confidential Figure 2. Furthermore, shutdowns have been driven by conditions not typical of springtime, such as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[23] Staff has also observed that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** occurred in months that are not included in the Company's "Economic Cycling Period."[24] This is illustrated in confidential Figure 3.

*Figure 3 - Hours in which economic shutdowns have occurred (confidential)*

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

**Q. Has Staff identified any instances in the 2021 TAM forecast whereby extending the "economic cycling period" would lower power costs?**

Potentially. Staff notes that PacifiCorp's **[BEGIN CONFIDENTIAL]** [redacted]

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[23] See the confidential electronic attachment to PacifiCorp's response to Staff DR 5.
[24] See the confidential electronic attachment to PacifiCorp's response to Staff DR 5.

[redacted] **[END CONFIDENTIAL]** of the Company's "economic cycling period."[25] Staff suspects that GRID may have modeled a longer shutdown if the unit had not been marked as "must run" from midnight on.[26]

**Q. What is Staff's recommendation regarding the "economic cycling period"?**

A. Staff recommends removing the "must run" setting from all of the Company's coal plant for every month of the year.

**Q. Please explain Staff's concerns regarding modeling economic shutdowns for only non-EIM participating units.**

A. The Company's participation in EIM has historically been a source of significant benefits to customers through forecasted lower power costs in the TAM. Nevertheless, Staff notes that the market conditions incentivizing economic shutdowns in spring, such as low market prices and low load, are the same conditions that PacifiCorp has identified as drivers of lower EIM benefits.[27] This suggests to Staff that as EIM benefits fall in spring, economic shutdowns could potentially provide more power costs benefits to customers than EIM participation.

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[25] See PacifiCorp's confidential electronic workbook "ORTAM21w Thermal Dispatch Check", tab name "Sheet 2".

[26] Staff notes that Hunter units 1 and 2 running at minimum load would provide an additional **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of generation to the Company. See Exhibit 203. PacifiCorp's confidential response (and attachment) to ALJ Bench Request 1.

[27] See PAC/200 Mitchell/6 - 9.

*Figure 4 – Actual economic shutdowns of EIM and non-EIM participating units (confidential)*

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

Staff is unaware of any physical or market reason why EIM participating units cannot be considered for economic shutdowns. As EIM participation can be opted into or out-of on a daily basis, EIM participation should not preclude economic shutdowns. In fact, Staff's analysis of historic instances of economic shutdowns at PacifiCorp has revealed that over the past four years, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the Company's economic shutdowns have been carried out on EIM participating units. This is demonstrated in confidential Figure 4.

**Q. How will the economic shutdown of EIM units affect the results of the EIM benefits model?**

A. It will make the forecast more precise. The results of the proposed model already reflect the economic shutdowns of EIM units that have occurred over the past several years, because it is based on the results of actual operations.

Currently, when PacifiCorp restricts the GRID by adding unrealistic conditions such as preventing EIM participating units from economic shutdowns, it removes a potential benefit from customers, without passing that benefit back in the TAM through increased EIM benefits.

**Q. How does Staff recommend its concerns about modeling shutdowns for exclusively non-EIM participating units be addressed?**

A. Staff recommends removing the "must run" setting from all of the Company's coal plant for every month of the year.

**Q. Please explain Staff's concerns regarding only the Company's majority-owned units being eligible for economic shutdowns.**

A. Growing numbers of energy companies are opting to shutter coal plants through either seasonal shutdowns or permanent closures, including Xcel, a co-owner of several of PacifiCorp's minority-owned plant.[28]

Notably, data provided to Staff by PacifiCorp indicates that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** [29]

Staff interprets this, and the documented changes affecting utilities across the US, as a sign that PacifiCorp's co-owners,[30] like themselves, may have an appetite for shutting down the plant when it is economic to do so.

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[28] PacifiCorp is a minority owner in six coal generator units: Colstrip units 3 and 4, Hayden units 1 and 2, and Craig units 1 and 2. Xcel Energy owns a stake in Hayden units 1 and 2, and Craig units 1 and 2.

[29] See the confidential electronic attachment to PacifiCorp's response to Staff DR 5.

[30] Staff expects that the **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** NorthWestern Energy, which is planning to increase its ownership share from 30 percent (majority share) to 55 percent in the coming months.

**Q. Has the Company engaged with its co-owners since this issue was raised by Staff in the 2020 TAM filing?**

A. Minimally. The Company reported in response to Staff discovery that it 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."[31]

**Q. How does Staff recommend its concerns regarding modeling economic shutdowns for only the Company's majority-owned units be addressed?**

A. Staff recommends the Commission require the Company to report on its efforts to engage with its co-owners, to identify which non-majority owned units could be economically shutdown in the future. Staff recommends the Commission order the Company to report to the Commission by January 1, 2021, with details of its efforts and status of discussions.

Staff notes that this is not an adjustment to GRID or NPC forecast, but a recommendation to try to identify new opportunities to benefit customers in a changing market. If the Company is successful in identifying opportunities for economic shutdowns at its non-majority owned plants, this would allow Staff and other interested stakeholders to work with the Company to accurately reflect actual operations in the NPC forecast.

[31] See Exhibit 204. PacifiCorp's response to Staff DR 11.

**Q. Please explain Staff's concerns regarding the limit on the number of startups.**

A. Although this limitation was presumably put in place to avoid excessive wear and tear in the generator units, this restriction may bring limited value to Oregon's ratepayers by unnecessarily restricting GRID's otherwise economic dispatch of the units.

**Q. How does Staff recommend its concerns about limiting shutdowns based on the number of startups be addressed?**

A. Staff's recommendation is twofold. First, remove the limit in the 2021 TAM filing. Second, if replaced, the limit on startups for future TAM filings should be informed by the comprehensive study into non-fuel economic shutdown costs and benefits recommended on page 20 of this section.

**Q. Please explain Staff's concerns regarding the modeled costs and benefits of economic shutdowns.**

A. As described on page 8, when modeling economic shutdowns, GRID accounts for the economic value of the shutdown, while incorporating the minimum up times, minimum down times, and startup costs.

The GRID model does not account for increased O&M costs from wear and tear,[32] decreases to O&M costs due to low running hours, or the multiple added benefits of economic shutdowns, such as helping to meet Clean Air Act requirements, reducing carbon emissions, and reducing pollution control costs.

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[32] See Exhibit 204. PacifiCorp's response to Staff DR 10.

Staff is concerned because to date, the Company has not carried out any analysis to quantify the financial impacts associated with economic shutdowns on non-fuel plant operation costs.[33] Staff considers this an important issue that should inform both forecasted and actual economic shutdowns going forward.

**Q. What is Staff's recommendation on this issue?**

A. Staff recommends the Commission require the Company to conduct a study to assess the additional non-fuel costs and savings of economic shutdowns. This study should be completed by January 1, 2021.

Staff expects this to provide valuable insights, which could be drawn on for years going forward in informing economic shutdown decisions.

**Q. Please provide a brief overview of Staff's concern that the "must run" condition applied to coal units may prevent opportunities for planned outages and economic shutdowns to be modeled together in GRID.**

A. In its 2020 TAM reply testimony, the Company argued that economic cycling that was related to outages and maintenance could not be considered as instances of economic cycling. [34] Staff disagrees with this, and believes that the planning of scheduled outages and economic shutdowns should in fact go hand-in-hand.

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33 See Exhibit 204. PacifiCorp's response to Staff DR 10.

34 See UE 356, PAC/400, Wilding/35, lines 15 – 17. "These very short extensions of maintenance-related outages (a few hours or days) are not the same as a one-or-two month shutdown of a plant for economic reasons. PacifiCorp 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 should not be included in Staff's analysis of actual economic cycling."

The crux of the matter is that when GRID models a decision to temporarily shut down a unit, it accounts for both the market price of power, and the unit's fuel running and start-up costs.[35] However, if the unit is already scheduled to come offline for an outage, the startup costs are "sunk costs" relating to the outage. This significantly reduces the economic hurdle for keeping the plant shut down, as the decision is a function of the generation cost, versus the market price for replacement generation, without added startup costs.

Data provided by the Company distinguishing between shutdowns preceding or following an outage or maintenance, and economic shutdowns occurring independently, support Staff's view. Historically, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** have occurred either preceding or following an outage or maintenance.

**Q. Has Staff engaged with the Company about this issue?**

A. Yes. Through discovery Staff learned that "*GRID determines the hourly commitment status of thermal units based on planned outage schedules, and a comparison of operating cost versus market price if the unit is capable of cycling up or cycling down in a short period of time. The commitment status of a unit indicates whether it is economical to bring that unit online in that particular hour*."[36]

[35] See UE 356, PAC/400, Wilding/33, lines 10 - 11. "The eligible coal plants incorporate the minimum up time, minimum downtime and startup costs as part of the economic dispatch parameters."
[36] See Exhibit 204. PacifiCorp's response to Staff DR 105.

The issue that remains unclear is whether the "must run" condition of coal units prohibit GRID from identifying the units as capable of cycling.

**Q. Has Staff identified any situations in the 2021 TAM in which economic shutdowns and planned outages could be combined?**

A. Yes, potentially. Staff reviewed the Company's scheduled outages for 2021, and notes that five of the outages are scheduled to begin on a Sunday or Monday.[37]

As power prices are typically lower on a weekend,[38] it may make economic sense for the unit to be shut down early. Staff's concern lays in the question of whether PacifiCorp's coal generator "must run" condition prevents GRID from identifying opportunities such as this.

**Q. How does Staff recommend its concerns about modeling shutdowns and planned outages together be addressed?**

A. Staff recommends removing the "must run" setting from all of the Company's coal plant for every month of the year.

**Q. Does Staff have any other issues to raise?**

A. Yes. Staff has two further concerns.

Staff notes that although PacifiCorp addresses only its coal shutdowns forecast in its TAM filing, that the Company also cycles its gas units on an

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37 Note that Staff actually observed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** See Confidential workpaper "ORTAM21 Planned Outages CONF", tab name "GRID_Planned Outages wo FO".

38 Lower weekend prices typically kick-in from Saturday evening, for example, Mid-C light load hours (LLH) begin at hour ending 2300 on Saturday and run through hour ending 0600 on Monday.

almost daily basis. Staff would like the Company to explain in reply testimony, how the economic cycling of gas units is modeled in GRID.

Following information provided at the Special Public Meeting on May 12, 2020, Staff would like the Company to provide reply testimony detailing the interplay between the forecasting of coal generation volumes prior to running GRID, and the forecasting of coal units in GRID. Staff would like the Company's testimony to specifically to address:

- How coal generation volumes are forecasted.
- How forecasted coal generation volumes compare to actual generation volumes.
- The interplay between forecasted coal generation volumes and the modeling of economic cycling.
- The interplay between the prices produced by the forecasted coal generation volumes and economic decision-making in GRID.
- How the Company ensures the GRID has arrived at an optimal economic forecast, given the pre-defined forecasted coal generation volumes.

## ISSUE 2, WHOLESALE POWER TRANSACTIONS

**Q. What wholesale power transactions are included in Net Power Costs (NPC)?**

A. The wholesale power transactions in NPC include long-term firm, short-term firm, [39] and system balancing transactions.[40] They also include QF purchases, storage and exchange costs, and EIM benefits.

*Figure 5 - Breakdown of wholesale power transactions*

| Wholesale Transactions ($ million) | Purchases | Sales |
|---|---|---|
| Long Term Firm | ($203.1) | $7.7 |
| Short Term Firm | | $4.9 |
| System Balancing | ($131.0) | $269.1 |
| Qualifying Facilities | ($337.6) | |
| Storage & Exchange | ($5.4) | |
| EIM Benefits | [BEGIN CONFIDENTIAL] [redacted] | |
| Total 2020 Forecast | [redacted] [END CONFIDENTIAL] | $429.9 |
| Total 2021 Forecast | ($612.5) | $281.6 |

As shown in Figure 5, EIM Benefits are accounted for as an offset to system balancing purchase costs.[41]

**Q. Please describe how each element of the Company's forecasted wholesale power transactions are derived.**

A. Each element is forecasted in a different way.

[39] Long-term firm transactions are wholesale contracts with a term-length of more than one year, while short-term firm transactions are wholesale contracts with a term-length of less than one year.
[40] System balancing transactions are market transactions modeled by GRID to economically balance load and resources on an hourly basis. See PacifiCorp's response to Staff DR 40.
[41] See PacifiCorp's confidential electronic workpaper "ORTAM21 NPC CONF", tab names "NPC", and "ORTAM20."

- *Short-term and long-term transactions* in the forecast reflect actual transactions already executed for delivery during the 2021 year, and will increase in subsequent updates to this filing as the Company completes its hedging for the year ahead.[42]
- *System balancing costs*, are market transactions which are forecasted by GRID as being required to balance the system. The system balancing transactions reported by the Company also include other minor transactions, representing Cal ISO imports and exports, emergency transactions, and trapped energy.
- *QF costs* represent the cost of acquiring power from PURPA projects. These costs are based on forecasted generation and contract prices. This is discussed further in Staff/400.
- *EIM benefits*, which include inter-regional transfer benefits and GHG benefits, are forecasted following the Company's proposed EIM benefit model, which is discussed further from page 27 of this section.

**Q. Please describe Staff's analysis of the Company's wholesale power transactions.**

A. Staff delved into the detail of the Company's NPC calculations, identifying each component of the Company's wholesale transactions. Staff also looked at multi-year trends in wholesale transactions, issuing 12 multi-part data requests to better understand the influences at play.

[42] See Exhibit 204. PacifiCorp's responses to Staff DRs 41 and 61.

Staff also investigated the Company's energy risk management and hedging policies, forward curves, and choice of trading counterparties.

**Q. Does Staff have a recommended adjustment?**

A. No.

## ISSUE 3, WESTERN ENERGY IMBALANCE MARKET BENEFITS

**Q. Please provide an overview of your testimony regarding EIM benefits.**

A. Staff's testimony is structured as follows:

- Overview of the EIM, of participating utilities, and the various EIM benefits.
- Overview of the Company's two proposed EIM benefits forecast models.
- Description of Staff's analysis and discussion of Staff's concerns.
- Summary of Staff recommendations regarding the EIM benefits forecast.

**Q. Please explain how the EIM functions.**

A. Electric generation and load must be instantaneously balanced for the electric grid to remain stable, as a large sustained imbalance between generation and load will cause both voltage and frequency instability on the grid. The balancing and coordination of generation assets is performed on several time scales, beginning months or weeks ahead with generation unit planning, on a day-ahead basis, and finally through real-time balancing, which is the realm of the EIM.

Utilities participating in EIM begin each hour with their forecast of load and generation balanced. This plan for running the system is referred to as the "base schedule." The utilities provide generation bids to the market for each generator unit, reflecting at what price they are willing to increase or decrease generation from their base schedule.

The EIM market's automated economic dispatch system looks across multiple BAAs to create a "merit order" of generation bids, prioritizing the lowest cost generation. The market dispatches the lowest cost generator to meet imbalances.  It also optimizes the Company's base schedule when savings are available.  This process is repeated in each five-minute period.

**Q. Who participates in the EIM?**

A. The EIM footprint includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, and the Canadian province of British Columbia. The current and planned new EIM participants are summarized in Figure 6 below. [43]

*Figure 6 - Timeline of EIM expansion*


**Q. What benefits does EIM participation provide to utilities?**

A. CAISO measures EIM benefits in three categories:

[43] See Exhibit 202. "Four Colorado power providers to join the California Western Energy Imbalance Market", press release from Black Hills Energy, December 17, 2019, and EIM website, periodically updated with the details of new participants http://www.westerneim.com/Pages/About/default.aspx.

- *Inter-Regional Transfer Benefits*: The largest benefit to participating in the western EIM is the economic efficiency of an automated dispatch model for both generation and transmission line congestion, which allows PacifiCorp to transact with CAISO and other EIM participants on a five- and 15-minute basis.
- *GHG Benefits*: Excess GHG revenues provide a substantial financial benefit to PacifiCorp's EIM participation.[44]
- *Flex Transfer Benefits*: The diversity of loads and variability of resources in the expanded footprint allows the Company to save money, by holding lower reserves than it otherwise would.

**Q. What EIM benefit has PacifiCorp forecasted for 2021?**

A. PacifiCorp has forecasted a system-wide benefit of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in 2021. This is the result of two forecasts, the first a forecast of inter-regional transfer benefits of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and GHG benefits of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million.[45]

**Q. How are EIM benefits reflected in rates?**

A. PacifiCorp's power cost forecasting model, GRID, does not consider EIM operations in its estimate of power costs. Consequently, the benefits of the

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[44] Energy generated in California or imported into the state to serve California load is subject to California's GHG obligation. The GHG adder in EIM is intended to compensate entities importing power into California for their compliance costs, and is paid to PacifiCorp when CAISO determines that generation within their BAAs served CAISO load. In this case, both the GHG emitting and non-GHG emitting resources generating at a node will receive the GHG adder. Excess GHG revenue results from the fact that non-GHG emitting resources do not have a compliance cost.

[45] See PAC/100, Webb/4, lines 10 - 11.

Company's EIM participation must be forecasted outside of the GRID model. To date, Staff, intervenors, and PacifiCorp have not agreed on an enduring model for EIM benefits.

The Company's forecasted EIM benefit is applied as an offset to power costs, and reduces the rates paid by customers.

**Q. Please describe how PacifiCorp's model forecasts EIM inter-regional transfer benefits.**

A. PacifiCorp's proposed market fundamentals approach for forecasting EIM inter-regional transfer benefits is a time-series regression forecast. PacifiCorp estimates import and export transfer benefits based on price and transfer volume explanatory variables. The prices used in the model include forward power and gas prices, while the transfer volumes are represented by the total transfer capacity of transmission and spring oversupply conditions.[46] The EIM transfer benefit forecast is the sum of the forecasted import and export transfer benefits for each of the PacifiCorp BAAs.

**Q. Please describe how PacifiCorp's model forecasts GHG benefits.**

A. PacifiCorp's GHG benefits model forecasts that future GHG benefits will equal past benefits, by taking average historic GHG benefits, and applying a quarterly seasonal shape to reflect **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[47]

[46] See PAC/200, Mitchell/4.
[47] See the confidential electronic attachment to PacifiCorp's response to Staff DR 33.

PacifiCorp's proposed GHG forecasting model uses data from December 2018 on, corresponding with an upward shift in GHG benefits following a change to CAISO's market policy.[48]

**Q. Please describe Staff's analysis of this issue.**

A. Staff's research included engaging in two workshops with the Company, held in January and April 2020, issuing substantial discovery, with a total of 40 data requests relating to this topic, and an in-depth investigation how EIM benefits have been forecasted in the past by PacifiCorp and Oregon's other Investor Owned Utilities (IOU). Staff also reached out to outside sources such as CAISO and WECC to inform this testimony.

Staff's analysis included analyzing calculations performed by the Company, verifying data inputs, auditing costs, and querying decisions.

Staff investigated the historic EIM benefits reported by CAISO, and PacifiCorp's alternative method of calculating actual EIM benefits. For the EIM transfer benefits model, Staff looked at the drivers of EIM benefits, the variables used, and the backcast of the model's performance versus previous forecasting models proposed in the TAM. Staff also looked at the potential for increasing PacifiCorp's EIM benefits by expanding the number of PacifiCorp's own generator units in EIM or through new EIM participants joining.

To inform its analysis of the GHG benefits model, Staff investigated GHG bidding in EIM, GHG compliance costs, purchases of California Carbon Allowances, the Company's use of offsets to meet its compliance obligations.

[48] See PAC/200, Mitchell/18 – 19.

Staff also investigated wheel-throughs in EIM, the nodal pricing model which comes into effect in January 2021, EIM costs, and the flexible reserve benefits PacifiCorp receives from EIM.

**Q. What concerns did Staff have with PacifiCorp's forecasted EIM benefits?**

A. Staff addressed the following concerns:

1) PacifiCorp's measurement of actual EIM benefits.

2) PacifiCorp's proposed model for EIM transfer benefits.

3) No reflection of EIM expansion.

4) Lack of forecasted growth in GHG Allowance prices.

5) Limited historic data to test for GHG model efficacy.

6) Flexible Reserve Benefits.

7) EIM costs.

8) Wheel-throughs in EIM.

**Q. Please describe how the Company measures actual EIM benefits, how this differs from the CAISO approach, and why this is significant.**

A. Staff noted that the Company calculates its inter-regional transfer benefits and GHG benefits using a different methodology than the CAISO, and that PacifiCorp does not track flexible transfer benefits. This concerned Staff, because the EIM benefit values calculated by the Company represent the input data for its proposed forecasting model.

Staff first considered total financial EIM benefits reported by PAC, compared to those reported by the CAISO. This analysis was restricted somewhat by the fact that the Company was unable to provide a breakdown of CAISO's benefit amounts between the three benefit types.[49]

PAC's measurement of EIM benefits fits closely with CAISO values in the most recent three years, however Staff is concerned by the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**,[50] summarized in confidential Figure 7. EIM benefits data from 2015 through 2019 is used as an input to the Company's proposed forecast of EIM transfer benefits, so the accuracy of this data is critical.

*Figure 7 - Comparison of CAISO and PacifiCorp's measurement of total EIM benefits (confidential)*

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

Staff then looked at each measured EIM benefit separately to assess the potential impact of this difference in approach.

49 See Exhibit 204. PacifiCorp's response to Staff DR 64.

50 Staff recognizes that a small proportion of this difference is due to GHG benefits not being included in PacifiCorp's values for 2015 and 2016. Staff calculated these values as a proxy for total EIM benefits, having received erroneous data in the confidential electronic attachment to PacifiCorp's response to Staff DR 17.

*Measuring Inter-Regional Transfer Benefits:*

CAISO methodology uses resource level imbalance energy, EIM prices and bids to calculate transfer values, associated costs, and avoided costs and intra-regional benefits. PacifiCorp's calculation is similar to CAISO's, but uses balancing authority area (BAA) level EIM transfer volumes, EIM prices, and a BAA level resource stack to determine the associated costs or avoided costs.[51]

Notably, PacifiCorp's measure does not account for intra-regional benefits;[52] however this is consistent with previous TAM filings, and the assumption GRID already reflects the optimized dispatch of PacifiCorp's generators within its BAAs.

Upon looking at the results of the Company's calculation of inter-transfer regional benefits, Staff was also concerned to see that negative benefits had been calculated for some months. Upon querying this with the Company, Staff learned that any negative values are removed prior to using the data as an input to the benefits forecast.[53]

Staff is satisfied with the Company's measurement of inter-regional transfer benefits since 2017, on the condition that negative monthly benefits are removed from all of the datasets before the model is run.

Staff has ongoing concerns about the measurement of total EIM benefits in 2015 and 2016. Staff expects that this difference is partially due to GHG

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51 See Exhibit 204. PacifiCorp's response to Staff DR 16.
52 Intra-regional transfer benefits refer to savings arising from the improved economic dispatch of the Company's own generators within its BAA.
53 See Exhibit 204. PacifiCorp's response to Staff DR 18, and redacted response to Staff DR 86.

benefits and flex transfer benefits being included in the CAISO calculation; however, this is difficult to conclude, because as mentioned previously, PacifiCorp has been unable to provide a breakdown of the values reported by CAISO.

Staff would like to see reply testimony from the Company to support the use of its measure of EIM benefits for 2015 and 2016, before the use of this input data for the Company's transfer benefits forecast can be supported.

*Measuring GHG benefits:*

CAISO measures GHG benefits as GHG revenues less the Company's GHG bid. PacifiCorp, on the other hand, calculates GHG benefits as GHG revenues less the Company's "compliance costs,"[54] measured as the cost to procure GHG Allowances for the energy attributed to serving CAISO load in the EIM.[55] As **[BEGIN CONFIDENTIAL]** [redacted] **END CONFIDENTIAL]** [56] the difference lays in CAISO using a forecasted GHG Allowance price, and PacifiCorp using an actual GHG Allowance compliance cost.

Staff investigated the Company's EIM compliance cost, by auditing purchases of GHG Allowances, the division of the Company's compliance obligation between its EIM operations and wholesale transactions into

[54] PAC/200, Mitchell/18, lines 9 – 10.

[55] See Exhibit 204. PacifiCorp's response to Staff DR 28, which states "The Company's compliance costs are the costs to procure California Carbon Allowances (CCA) for the energy attributed as serving California Independent System Operator (CAISO) load in the energy imbalance market (EIM)."

[56] See Exhibit 203. PacifiCorp's confidential response to Staff DR 88.

California, and the Company's use of GHG Allowance offsets[57] to meet its compliance obligation. Staff was unable to verify that the EIM compliance cost has been calculated as described, and despite issuing discovery to clarify this, the Company was unable to provide Staff with its calculations of the EIM compliance cost, which it claims is used in in calculating GHG benefits.[58]

**Q. Does Staff have a proposed adjustment relating to PacifiCorp's calculation of actual EIM benefits?**

A. Yes. Staff recommends the Commission reject the Company's calculation of EIM transfer benefits for 2015 and 2016. Additionally, Staff recommends the Commission reject the Company's calculation of GHG benefits.

Staff has significant concerns with the data being used by PacifiCorp. Staff requests that the Company address the differences in CAISO and PacifiCorp's calculation of EIM benefits in 2015 and 2016 in its next round of testimony.

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[57] California's Cap-and-Trade program allows the use of GHG reducing offset projects to meet compliance obligations. One example of this is PacifiCorp's involvement in the livestock methane dairy digester project, Farm Power Lynden. Staff approximates that the value of the offsets acquired from this project is approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which is the difference between the Company's average GHG Allowance purchase price during the period the project offsets were received (2016 to April 2020), and the cost of the offset allowances). See the confidential electronic attachment to PacifiCorp's response to Staff DR 32. Also see Exhibit 203. PacifiCorp's confidential response to Staff DR 99.

[58] See Exhibit 204. PacifiCorp's response to Staff DR 93. *Request:* "Please supplement the Company's response to Staff DR 31 with…(e) The Company's California Carbon Allowance compliance cost in dollars for EIM exports. *Response:* "the Company has not performed the requested analysis. The Company does not make separate greenhouse gas (GHG) California carbon allowance purchases for day-ahead / hour-ahead and energy imbalance market (EIM) compliance. Since these allowances are purchased together, to try and separate them after the fact would merely be a best guess. Once the Company's yearly California carbon allowance total obligation is trued up from the estimate, deficiencies may be purchased months after the year has ended along with allowances for the current year. This true up process makes it even more difficult to separate the purchased GHG California carbon allowance purchases between day-ahead / hour-ahead and EIM after the fact."

This should be accompanied by compelling evidence as to why the Company's measure is more accurate than CAISO's.

Further, Staff requests that the Company demonstrate in detail how it has calculated EIM compliance costs, and how GHG Allowances purchases, GHG Allowances offsets, and generator emission factors are used.

**Q. Please explain Staff's concerns with PacifiCorp's proposed transfer benefits forecasting model.**

A. PacifiCorp tried three different approaches to model its inter-regional transfer benefits: a linear trend forecast,[59] an exponentially weighted moving average forecast,[60] and a market fundamentals approach.[61]

The Company argues that it can assess the accuracy of the models by forecasting "*the 2019 EIM transfer benefits using the historical EIM transfer benefit data from January 2015 – December 2018 and the actual 2019 market prices as inputs into the statistical models*."[62] Based on this analysis, PacifiCorp found the linear trend and exponentially weighted moving average forecasts "*to be less reliable and less consistent than PacifiCorp's market fundamentals approach*."[63] Thus, it proposes to use its market fundamentals approach to forecast transfer benefits in the 2021 TAM.

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59 The linear trend forecast represents the model used to forecast EIM transfer benefits in the 2019 TAM, and supported by Staff in the 2020 TAM. See UE 339, PAC/100, Wilding/44 – 45, and UE 356, Staff/300, Enright/12.

60 The exponentially weighted moving average forecast represents an alternative model proposed by the Citizen's Utility Board for forecasting transfer benefits in the 2020 TAM. See UE 356, CUB/200, Gehrke/7.

61 PacifiCorp also proposed using a market fundamentals approach for forecasting transfer benefits in the 2020 TAM. See UE 356, PAC/100, Wilding/29.

62 See PAC/200 Mitchell/16, lines 14 – 16.

63 See PAC/200, Mitchell/13, lines 18 – 19.

Staff finds PacifiCorp's method of comparing model performance problematic, because when 2019 forecasts were being prepared the actual 2019 market prices were unknown. If the goal is to compare which forecast method would have produced the best 2019 forecast, then it is inappropriate to use actual 2019 market prices.

Furthermore, Staff notes that the model that performed best in 2019 will not necessarily perform best in 2021. There are benefits to each of the proposed models, for example because an exponentially weighted moving average favors more recent observations, it might be a good way to capture recent EIM changes.

**Q. Does Staff have a recommendation on this matter?**

A. At this time, Staff does not have a recommendation but requests that that PAC recreate what the 2019 forecast would have been with each of the three models, using only the data that was available at the time of the final update to the 2019 TAM, and provide this information in its next round of testimony.

**Q. Please explain Staff's concern that there is a lack of forecasted growth from new EIM participants being reflected in the Company's model.**

A. In previous TAM filings, the Company and Staff had witnessed increasing EIM benefits in line with the addition of new entrants to the market.[64] Nevertheless, the Company's proposed inter-regional transfer benefits forecasting model accounts only for increases in transmission capacity between PacifiCorp and

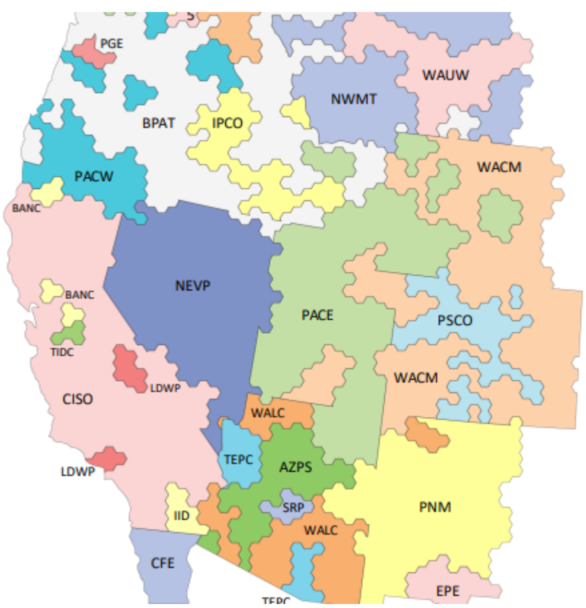
[64] See UE 339, PAC/100, Wilding/40, lines 15-18.

CAISO, leaving increased transmission capacity between PacifiCorp and new EIM participants unaccounted for.[65]

In its opening testimony, PacifiCorp explained that new EIM entrants in 2020 and 2021 were expected to have a minimal impact on forecasted EIM inter-regional transfer benefits, as they would represent an unsubstantial increase in load served, and more importantly, brought little to no transmission connectivity between themselves and PacifiCorp.[66]

Staff was concerned by PacifiCorp's explanation, as it relied on outdated information from July 2019.[67] Staff's investigation found that in December 2019 a further four Colorado utilities committed to joining the EIM in 2021. In total, nine new participants are expected to join the EIM in 2021, and a further four are expected in 2022. This represents a substantial addition to the EIM, which the market operator has called “one of its largest expansion periods”.[68]

*Figure 8 – Locations of WECC BAAs*




The largest of the Colorado utilities is Public Service Company

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[65] See Exhibit 204. PacifiCorp's response to Staff DR 24.

[66] PAC/200, Mitchell/12 states “The EIM footprint currently encompasses approximately 60 percent of Western Electricity Coordinating Council load and the entities joining the market in 2020 and 2021 will not increase this percentage substantially. More importantly, the new entrants bring little to no transmission connectivity between themselves and PacifiCorp. With these factors combined, the projected impact to PacifiCorp's EIM transfer benefits is expected to be minimal.”

[67] See PAC/200, Mitchell/12, footnote 3.

[68] See Exhibit 202. News release from CAISO, April 30, 2020.

of Colorado (PSCo), which serves 75 percent of load in Colorado. PSCo, along with NorthWestern Energy (NWMT), which will also join the EIM in April 2021, shares a significant border with PacifiCorp.

**Q. Please detail Staff's analysis of this subject.**

A. Through discovery, Staff learned that PacifiCorp considers its connectivity to the CAISO to be more valuable in terms of creating EIM benefits than its connectivity to the rest of the EIM participants for *imports*. This is due to the combined solar, wind, and hydroelectric capacity of the CAISO, which lead to low EIM prices during the middle of the day in spring, driving the majority of PacifiCorp's EIM import transfer benefits in both the East and West balancing authority areas.[69] The Company provided ample evidence of low prices, and of wind and solar oversupply, to support this stance.[70]

*Figure 9 - Transfer benefits derived from exports and imports in 2019 (confidential)*

**[BEGIN CONFIDENTIAL]**

[redacted]

**[BEGIN CONFIDENTIAL]**

[69] See Exhibit 204. PacifiCorp's response to Staff DR 22.
[70] CAISO data on solar and wind oversupply is accessible at http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

Nevertheless, Staff does not find PacifiCorp's explanation compelling enough to justify the exclusion of other transfer benefits from the forecast. Notably, PacifiCorp stated that it finds CAISO connectivity to be more valuable for *imports*. As demonstrated in confidential Figure 9,[71] transfer benefits from imports amounted to **[BEGIN CONFIDENTIAL]** [redacted].**[END CONFIDENTIAL]**

**Q. Does Staff have a recommendation on this matter?**

A. At this time, Staff does not have a recommendation but requests that that PacifiCorp update its proposed methodology to account for the record EIM growth expected in 2021 and 2022, with a view to reflecting the incremental benefits of increased EIM participation. Staff requests that PacifiCorp provide this information in its next round of testimony, including supporting data and explanations for its proposed approach.

**Q. Please explain Staff's concern related to a lack of forecasted growth in California Carbon Allowances prices being reflected in the Company's model.**

A. GHG Allowance prices are designed to increase each year. This occurs because auction reserve prices rachet up each year,[72] while the cap on emission reduces, creating scarcity in the market. GHG Allowance prices at

[71] Compiled by Staff using data provided in the confidential electronic attachments to PacifiCorp's response to Staff DRs 16 and 17.

[72] In accordance with 95911(c)(3) of the California Regulation, California Carbon Allowances auction reserve prices are calculated as the auction reserve price for the previous calendar, increased annually by five percent plus the rate of inflation as measured by the most recently available twelve months of the Consumer Price Index for All Urban Consumers.

auction cleared at 7 percent above the auction reserve price in the first quarter of 2020.[73]

GHG Allowance prices are a direct input to GHG bids, which in turn are reflected in GHG Allowance prices. As PacifiCorp explained to Staff: *"as the GHG price increases, the spread between the GHG revenue and the GHG cost increases for all resources that are infra-marginal.[74] This spread is a resource's GHG benefit."*[75]

A recent example of this relationship is the upward shift in PacifiCorp's GHG benefits, occurring in-line with increasing GHG prices, due to the November 2018 CAISO policy change.[76]

**Q. What is Staff's recommendation on this issue?**

A. Staff recommends increasing the GHG Benefit forecast by five percent plus inflation for each twelve month period, and proportionately for periods of less than one year.

**Q. Please explain Staff's concern related to the limited availability of data for testing the Company's proposed GHG model.**

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[73] See Exhibit 202. "California-Quebec carbon auction kicks off 2020 with record allowance price", by Environmental Defense Fund, February 26, 2020.

[74] "Infra-marginal" refers to units that are within the margin, rather than at the margin. For example, unit A has a GHG bid of $0/MWh, while unit B has a GHG bid of $7/MWh. If unit B is the marginal generator (setting the GHG price at $7/MWh), unit A would be an infra-marginal unit, earning a GHG benefit of $7/MWh (revenue of $7/MWh minus compliance cost of $0/MWh). If the GHG price increases to $20/MWh, unit A's GHG benefit will increase to $20/MWh. For a more detailed version for this example, demonstrating specifically how the November 2018 policy change affected GHG prices. See Exhibit 204. PacifiCorp's response to Staff DR 68.

[75] See Exhibit 204. PacifiCorp's response to Staff DR 68.

[76] See Exhibit 204. PacifiCorp's response to Staff DR 34.

A. Staff's concern related to the GHG benefits forecast, in which PacifiCorp proposes to use data only from the post November 2018 period, is because of the implementation of a new CAISO methodology in November 2018,[77] which affected PacifiCorp's GHG benefits.

Staff was initially concerned about using such a short period of actual data in the forecast, however having pulled the GHG benefits data for the period since 2017, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**This shift is illustrated in confidential Figure 11.[78]

*Figure 10 - GHG benefits January 2017 - December 2019*

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

**Q. What is Staff's position regarding the limited availability of data for testing the Company's proposed GHG forecasting model?**

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77 PAC/200, Mitchell/18 - 19.

78 Compiled by Staff using data provided in the confidential electronic attachment to PacifiCorp's response to Staff DR 33.

A. Staff agrees that historical values are generally a prudent forecast when the appropriate causal factors have not yet been identified. However, considering Staff's concerns with the Company's calculation of actual GHG benefits discussed on page 36, Staff does not support the Company's approach.

**Q. Please explain flexible transfer benefits, as related to Staff's concerns.**

A. As mentioned on page 29, the diversity of loads and variability of resources in EIM allow the Company to save money by holding lower reserves than it otherwise would require. In addition to saving money, the Company may earn flexible reserves revenue for reserves provided.

CAISO calculates flexible transfer costs by calculating a BAA's net flexible ramping award, multiplied by the flexible ramping shadow price. The result of this calculation is that when a BAA exports flexible ramping products it receives compensation from other BAAs, and when the BAA imports flexible ramping product, it pays other BAAs for providing the service.[79]

**Q. Please explain Staff's concerns.**

A. Staff's concerns are twofold.

First, PacifiCorp does not account for flex transfer in its EIM benefits calculation. It states that these benefits are accounted for in GRID through a 104 MW system-wide reduction to its reserve requirement,[80] and as such do not need to be account for in the Company's EIM benefit forecasting model.

[79] See CAISO's EIM benefit methodology, accessible at: https://www.westerneim.com/Documents/EIM_BenefitMethodology.pdf.

[80] See Exhibit 204. PacifiCorp's response to Staff DR 19.

The 104 MW value was provided by PacifiCorp in its 2019 IRP. Staff investigation found at the time the IRP study was carried out, only four full months of data were available, covering the period from March 2018 to the beginning of July 2018.[81] Given that at least two years' worth of data is now available, Staff believes it would be correct for the IRP modeled figure to be updated with data from the most recent twelve months available.

Second, PacifiCorp's approach does not account for *revenue* derived from *providing* flexible reserves. Staff has attempted to investigate the level of revenues received by the Company, but was informed that the Company "has no archive of the CAISO calculated benefits or the breakdown of these benefits into its components."[82]

**Q. What is Staff's recommendation regarding flexible reserve benefits?**

A. With regard to Staff's first concern, regarding the 104 MW flexible transfer benefit value, Staff recommends that PacifiCorp: update the IRP model with data from the most recent twelve months available for use in calculating flexible reserve benefits in this case. Staff will continue to monitor this issue as further data becomes available from CAISO to evaluate whether the addition of new participants add incremental benefits to the flexible reserve benefit.

With regard to Staff's second concern, revenue derived from providing flexible reserves, Staff recommends PacifiCorp: request copies of the CAISO

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81 See Exhibit 202. Appendix F to PacifiCorp's 2019 IRP, "Flexible Reserve Study", pages 100 – 102, which explains that data exclusively from March 2018 onward is used in the study because of an error that was identified in CAISO's calculations affecting data issued prior to March 2018.

82 See Exhibit 204. PacifiCorp's response to Staff DR 64.

benefits calculations from CAISO on a quarterly basis beginning with quarter one 2019, and that it maintain this data, making it available for consideration by Staff in future filings.

Considering the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** observed by Staff between the EIM benefits measured by CAISO those measured by the Company in recent years (as seen in Figure 7 on page 33),[83] Staff does not have an adjustment related to this issue, but will continue to consider this in future TAM filings.

**Q. As related to Staff's seventh concern, please explain what EIM O&M costs are being recovered in this filing, and how that differs from previous TAM filings.**

Fixed EIM costs were recovered through the TAM in 2019 and 2020, in accordance with Order No. 18-421. Beginning with the 2021 TAM, fixed EIM costs will no longer be recovered in the TAM, and will instead be dealt with in the Company's general rate case, Docket No. UE 374. This change results in a $1,456,461[84] system-wide reduction to the EIM costs being recovered in the TAM.

EIM Grid Management Charges (GMC), will continue to be recovered in the TAM, as they represent variable EIM costs. Staff audited the Company's past GMCs, and its forecast of GMCs for 2021, and has found no issues with the

[83] The CAISO value is the sum of flexible reserve benefits, transfer benefits and GHG benefits, while PacifiCorp's value is the sum of transfer benefits and GHG benefits only. Therefore, the difference between these values can be attributed to flex reserve benefits, and measurement differences.
[84] Exhibit PAC/101, Webb/1.

data. Staff notes that the forecast is based on actual GMCs incurred in the period July 2018 to June 2019, and is consistent with the 2020 TAM filing.

Finally, in the 2021 TAM, a $8 million system-wide cost relating to the PacifiCorp's Nodal Pricing Model Agreement with CAISO will be recovered for the first time. This is discussed further in Staff/100.

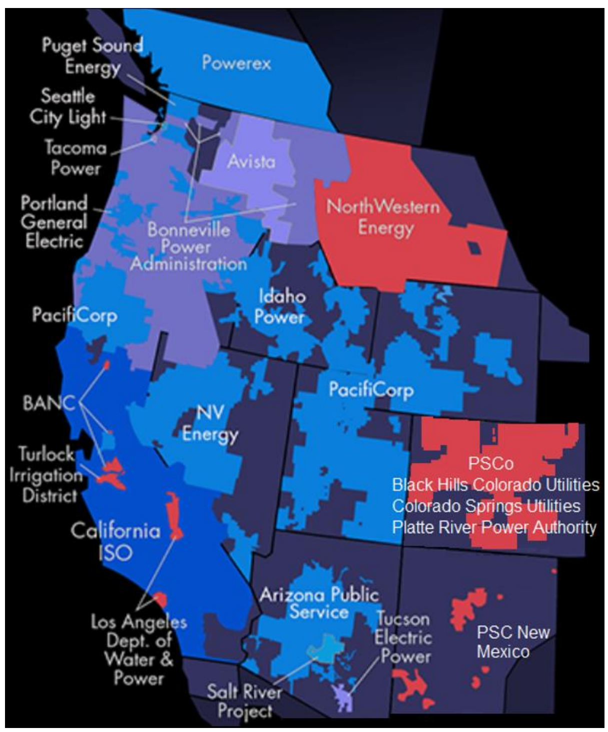
**Q. Does Staff have any recommendations regarding the recovery of EIM costs in this filing?**

A. No.

**Q. Staff's final concern relates to wheel-throughs in EIM. Please explain why this is significant.**

A. Staff's concern stems from the fact that EIM entities that facilitate wheeling power do not currently receive any benefit for doing so.

*Figure 11 - Map showing PacifiCorp's physical location in the EIM footprint*




Oregon's IOUs are in somewhat advantageous locations in relation to other EIM participants. As the EIM footprint grows, for example with the addition of four Colorado utilities and NorthWestern Energy in 2021, which share their EIM border with PacifiCorp, wheel-through transfers are likely to become more common.

*Figure 12 - CAISO estimated wheel through transfers in Q1 2020*

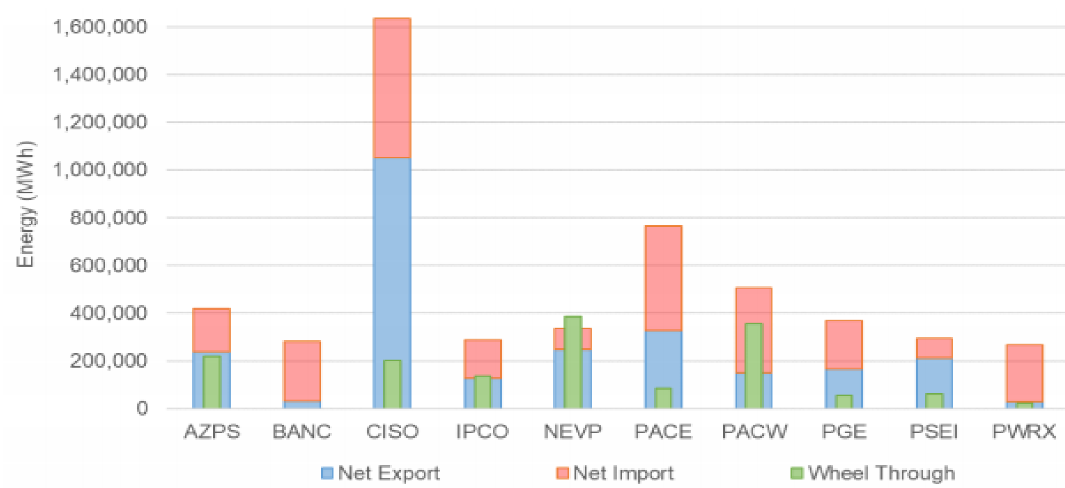



Figure 12 demonstrates how PAC's system is already used for high volumes of wheel-throughs.[85]

**Q. Has any action been taken on this matter?**

A. CAISO has committed to monitoring EIM wheel-through volumes[86] to assess whether as the EIM grows, a market solution may be needed to ensure that wheeling benefits are shared equitably between the sink, source, and facilitating EIM participants.

Although PacifiCorp has not conducted an analysis of the value lost through EIM wheel-through transfers in its territory,[87] Staff notes that it has become

[85] EIM benefits report for Quarter 1 2020. Accessible at: https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ1-2020.pdf.

[86] CAISO's undertakes monitoring of wheel-through volumes via the Western EIM Consolidated Initiatives stakeholder process.

[87] See Exhibit 204. PacifiCorp's response to Staff DR 27.

involved with other EIM entities in taking a position on transmission elements of an extended day-ahead market design.[88]

**Q. Does Staff have any recommendations on this matter?**

A. Not at this time, however Staff will continue to monitor this issue .

[88] See the joint presentation delivered by the EIM entities accessible at: http://www.caiso.com/InitiativeDocuments/Presentation-ExtendedDay-AheadMarket-TransmissionProvision-EIMEntities.pdf.

## ISSUE 4, DAY AHEAD/REAL TIME (DA-RT) ADJUSTMENT

**Q. Please provide background on the DA-RT adjustment.**

A. The DA-RT adder was approved in the 2016 TAM, in Order No. 15-394. It has been a highly contentious issue, being contested by Staff or intervenors in all but one TAM filing since then.[89] PacifiCorp remains the only Oregon Investor Owned Utility applying such an adjustment to its power cost forecast.

In the 2021 TAM, the DA-RT adder will increase customer costs by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[90] on a system-wide basis, and $11.3 million on an Oregon-only basis.[91]

**Q. Please explain the DA-RT adjustment.**

A. The DA-RT adder is made up of two adjustments:

- Volume adder. This adder reflects the fact that PacifiCorp must transact in the market in set quantities, e.g. a 25 MW block, while GRID does not have this restriction and instead buys and sells MW of any quantity.
- Price adder. This creates distinct prices in GRID for system balancing sales and purchases, aiming "to better reflect the market prices available to the Company when it transacts in the real-time market."[92]

**Q. Please describe Staff's analysis of this issue.**

A. Staff issued 24 multi-part Data Requests relating to the DA-RT model. As this is a highly complex adjustment, Staff spent a significant amount of time

[89] The DA-RT adder was contested in UE 297, UE 307, UE 323, and UE 356.
[90] See PacifiCorp's confidential electronic workbook "ORTAM21 Testimony Support CONF".
[91] See PAC/100, Webb/18, line 11.
[92] See UE 339, PAC/100, Wilding/27.

looking into the mechanics of the DA-RT volume and price calculations. In addition to this, Staff investigated the Company's choice of market hubs to which the DA-RT adder is applied, the knock-on effect of the DA-RT adder on other wholesale transactions other than system balancing transactions, the Company's historic transactions, and the effects of the Company's EIM participation on DA-RT trading processes.

**Q. What is Staff's recommendation on this issue?**

A. Staff does not have an adjustment to the DA-RT adder in this case.

Staff is aware that PacifiCorp plans to use the AURORA model to forecast NPC in the 2022 TAM. Given that the DA-RT adder was created to compensate for deficiencies in their GRID model,[93] Staff recommends using the switch to AURORA as an opportunity for collaboration between Staff, the Company and intervenors, to determine how and whether the DA-RT adjustment is appropriate once AURORA is used to forecast power costs.

The objective of this collaboration would be to eliminate or at least reduce the need for out-of-model adjustments for DA-RT transactions, rather than carrying forward and adjusting for GRID's perceived modeling deficiencies in perpetuity.

Therefore, Staff recommends that the Commission require the Company to hold a workshop on this issue by April 1, 2021. Issues Staff would like to see resolved include, but are not limited to:

[93] See UE 296, PAC/100, Dickman/21 – 30.

1) *Volume Adder.* As explained above, the volume adder exists to reflect the fact that GRID buys and sells MW of any quantity, but PacifiCorp must transact in the market in 25 MW clips. Staff expects that the logic in PacifiCorp's new AURORA model could easily be set to recognize the need to transact in 25MW clips, eliminating the need for the out-of-model volume adder.

2) *Price Adder.* The price adder creates distinct prices in GRID for system balancing sales and purchases, however **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[94]

*Figure 13 - Example of DA-RT Price Adder (confidential)*

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

See confidential Figure 13, which shows and example taken from the current TAM filing. Historically, PacifiCorp has purchased peak power in February at a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to the forecasted price. Limitations in the GRID model do not allow PacifiCorp to reflect these historic results. Instead it

[94] See PacifiCorp's confidential workbook "ORTAM21w_DA-RT Price Adder (1912) CONF xAdders.xlsx", tab name "Adders", cells B236 to Z261.

substitutes a mid-price for both buying and selling, meaning that the historic benefit is not reflected in the model, only the historic loss is reflected. This occurs in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** price adder calculations.

3) *EIM balancing transactions.* Further, the DA-RT model was specially designed to reflect price differences in system balancing transactions. It was approved in December 2015, at a time when PacifiCorp had been operating in EIM for just twelve months, and was one of only two EIM participants.[95] With the Company now carrying out many balancing purchases and sales in EIM, PacifiCorp's move to using the AURORA model presents an opportunity to review the continued relevance of the DA-RT adder.

4) *Day ahead market and Nodal Pricing Model*. Considering the potential introduction of a day-ahead market in the coming years, and PacifiCorp's commitment to using a nodal pricing model from January 2021 onward, the dynamic of its DA-RT adder is likely to change. These changes, and the Company's move to forecasting NPC with AURORA, present an opportunity for the model to reflect PacifiCorp's actual operations going forward, rather than continuing to focus on four years' of past results.[96]

5) *Hourly transactions.* Staff has argued on more than one occasion that the use of hourly or daily data in DA-RT calculations would provide more accurate results. This could also be explored in-line with the transition to AURORA.

[95] The third EIM participant, NV Energy, joined in December 2015.
[96] The DA-RT adder uses four years of historical data to inform future balancing transactions. See Exhibit 204. PacifiCorp's response to Staff DR 13.

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

A. Yes.

CASE: UE 375
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 201

# Witness Qualifications Statement

**May 15, 2020**

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| NAME: | Moya Enright |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Economist<br>Energy Rates, Finance and Planning Division |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | Energy Risk Professional Certification (part-qualified).<br>Global Association of Risk Professionals.<br><br>M.Sc. Political Science, 2015.<br>University of Amsterdam.<br><br>M.Sc. Investment, Treasury and Banking, 2011.<br>Dublin City University.<br><br>B.A. International Business and Languages, 2008.<br>Dublin City University through a joint curriculum with École Supérieure de Commerce de Montpellier. |
| EXPERIENCE: | Senior Utility and Energy Analyst at OPUC since January 2019.<br><br>Energy Trader for Meridian Energy from 2015 to 2019. Meridian Energy is a power generator and retailer operating both in New Zealand and Australia.<br><br>Trading and Operations Analyst at Tynagh Energy from 2011 to 2013. Tynagh Energy is an independent power producer operating in the Republic of Ireland.<br><br>Senior Electricity Market Controller at EirGrid from 2008 to 2011. EirGrid is the Irish electricity Transmission System Operator. It operates the Single Electricity Market for the Republic of Ireland and Northern Ireland.<br><br>Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG in Northern Ireland. |

CASE: UE 375
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 202

## Exhibits in Support
## Of Opening Testimony

**May 15, 2020**

**The Coal Cost Crossover: 74% Of US Coal Plants Now More Expensive Than New Renewables, 86% By 2025**

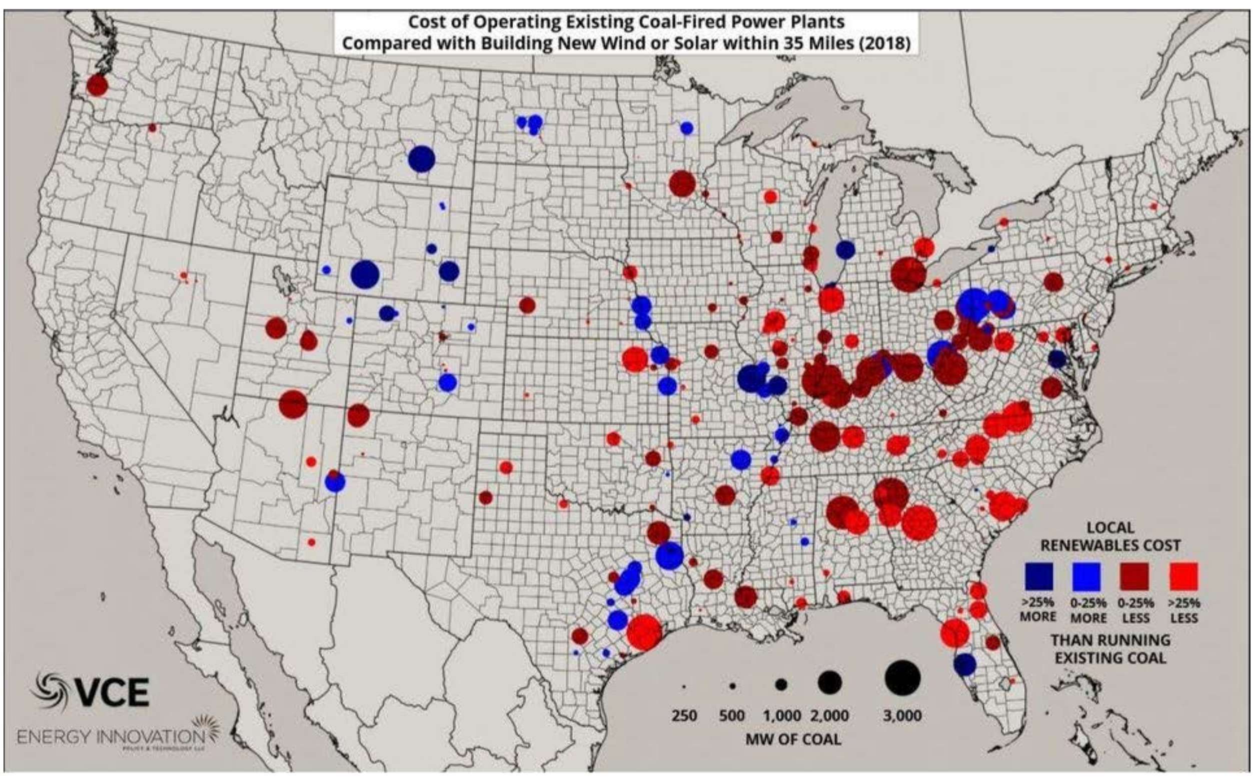
*By Silvio Marcacci – Forbes, 03.26.2019.*

**Renewable energy has been beating coal on cost in many parts of the United States for years**, but now we know exactly where coal is out of the money compared to renewables – and exactly how far coal generation is in the red.

New research from Energy Innovation and Vibrant Clean Energy (VCE) shows **the U.S. has officially reached the coal cost crossover point**, where fast-falling wind and solar prices make simply **operating three-quarters of all existing coal generation plants more expensive than building new local renewable energy** .

In 2018, 74% of the national coal fleet was "at risk," meaning the plants could be replaced with new wind or solar generation within 35 miles of each plant cheaper than the combined fuel, maintenance, and other going-forward costs of running those plants. By 2025, at-risk coal increases to a whopping 86% of the entire existing U.S. generation fleet, even as federal renewable energy tax credits phase out.

**The coal cost crossover raises serious questions for regulators and utilities as to why these coal plants should keep running unprofitably and at extra cost to consumers** , instead of being replaced with new renewable energy generation.

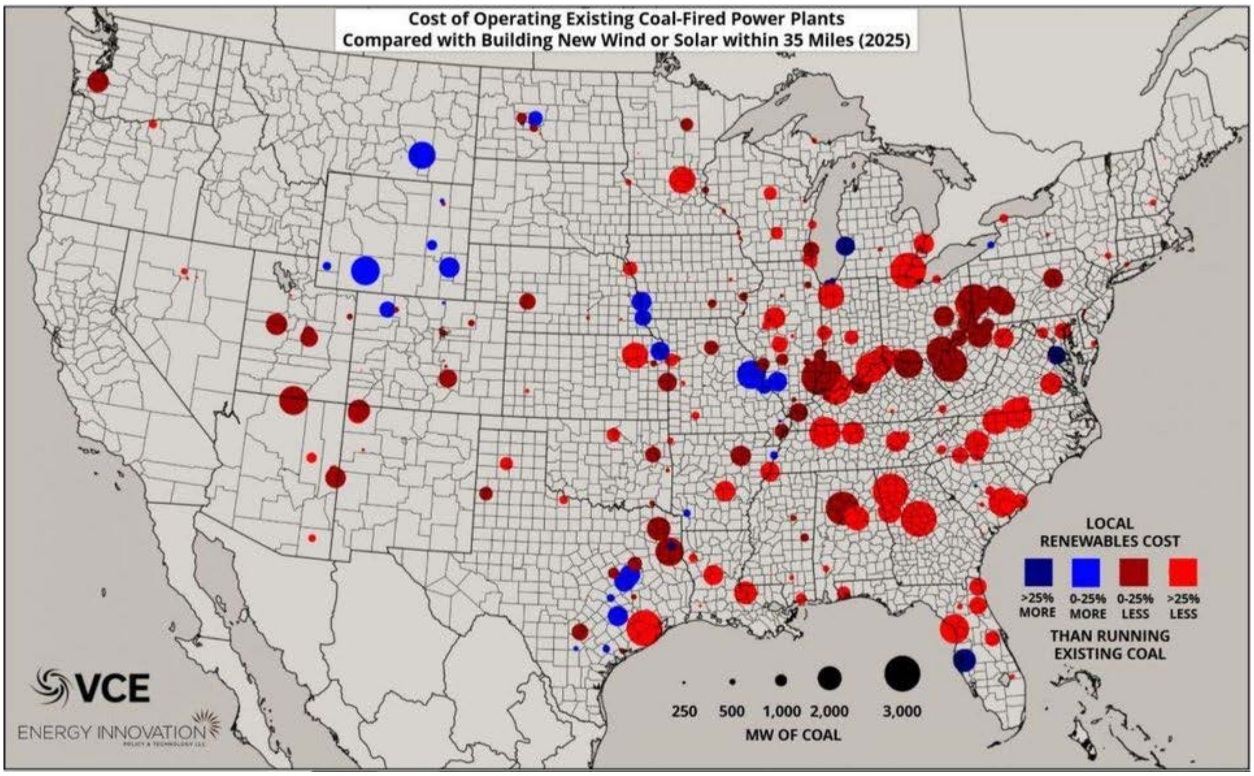



*Cost of operating existing coal-fired power plants compared with building new wind or solar within 35 miles, **2018** ENERGY INNOVATION/VIBRANT CLEAN ENERGY*

The “Coal Cost Crossover”

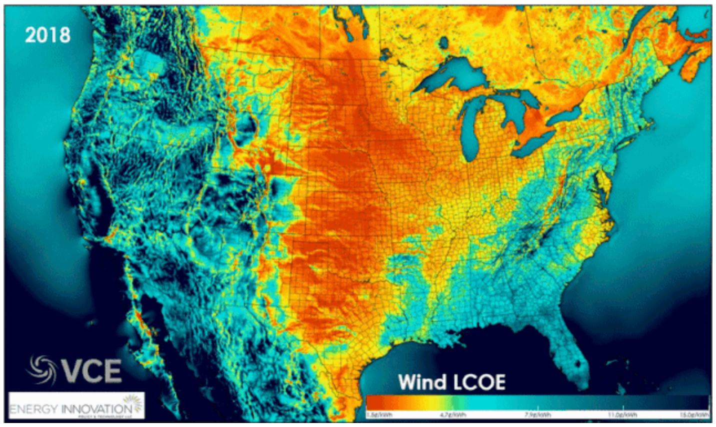
The new Energy Innovation-VCE analysis uses multiple data sources to compare each coal plant’s marginal cost of energy (MCOE) to the lowest levelized cost of energy (LCOE) for wind or solar resources within 35 miles of that plant to determine if it has reached the coal cost crossover point.

**In 2018, 211 gigawatts (GW) of existing U.S. coal capacity were at risk and operating at higher costs for consumers than cheaper wind and solar energy, and by 2025 that number jumps to 246 GW.**



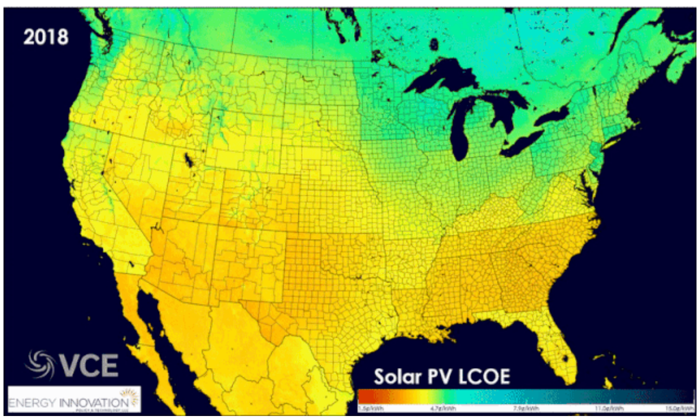

*Cost of operating existing coal-fired power plants compared with building new wind or solar within 35 miles, **2025** ENERGY INNOVATION/VIBRANT CLEAN ENERGY*

Previous research has shown solar photovoltaic energy prices fell 90% and onshore wind prices declined 65% in the past decade, and our new analysis reveals pricing for new renewable energy generation as low as \$15 per megawatt-hour (MWh) for wind and \$28/MWh for solar.



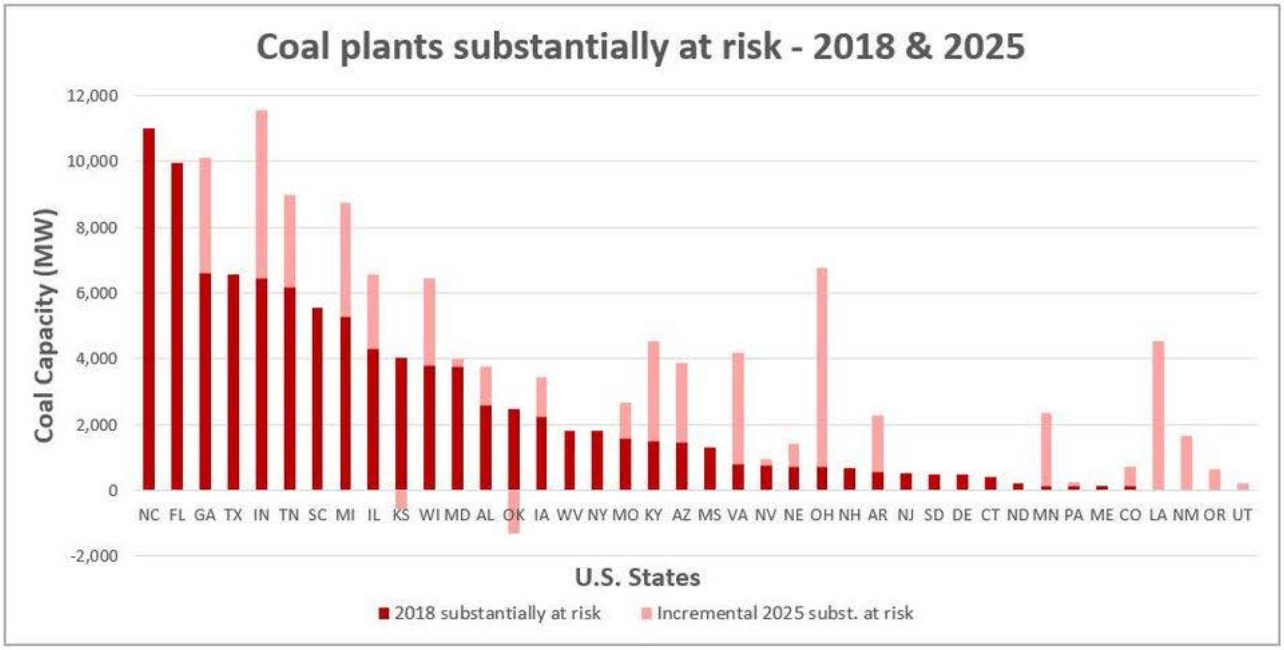

*Map of the levelized cost of energy for U.S. wind projects in 2018 using VCE dataset ENERGY INNOVATION/VIBRANT CLEAN ENERGY*

And while wind energy resources are fairly concentrated in Midwest states, solar price forecasts made using the National Renewable Energy Laboratory Annual Technology Baseline project solar will soon be cost-competitive with coal-fired electricity in nearly every corner of the U.S.




*Map of the levelized cost of energy for U.S. solar photovoltaic projects from 2018 to 2025 using VCE dataset. ENERGY INNOVATION/VIBRANT CLEAN ENERGY*

These additional price declines mean that not only will coal-fired power be more expensive than new renewables, it will soon be dramatically uneconomic by comparison. By 2025, “substantially at-risk” coal – meaning coal plants with operational costs at least 25% higher than building new local wind or solar generation – rises from 94 GW in 2018 to 140 GW, or roughly half the existing U.S. fleet.




**U.S. coal plants substantially at risk 2018 and 2025**. *ENERGY INNOVATION/VIBRANT CLEAN ENERGY*

Our analysis represents high confidence that replacing substantially at-risk coal plants with local renewable energy would immediately yield cost reductions, and these plants also raise the potential for resources like demand response or energy storage to cost-effectively tackle intermittency concerns.

While using solely local resources makes this analysis quite conservative, building local renewables in the immediate vicinity of coal plants is quite important for the economic transition of coal-dependent communities. This implies wind and solar could replace lost jobs, expand the tax base, and reuse transmission, all within the same local region or often the same utility territory. So communities get cleaner, with cheaper electricity costs, and stronger economies – all through the coal-to-clean transition.

Unlocking the coal-to-clean transition for utilities

Any coal plant failing the cost crossover test should be a wake-up call for regulators, utilities, and the public that clean energy transition opportunities exist in the immediate vicinity of that plant. But this is just the first step in thinking about closing U.S. coal, and replacing that output with new wind and solar energy will be more complex in practice.

Some forward-looking utilities are already tackling this challenge – Xcel Energy is targeting 100% clean energy by 2050, and Indiana's NIPSCO intends to replace all its coal generation with clean energy within ten years – but the utility industry can't go it alone.

Policymakers must enable utilities to profitably retire uneconomic coal generation and unlock clean energy potential. Coal securitization legislation has just been enacted in New Mexico by Governor Lujan-Grisham and is being considered in Colorado's state legislature with the endorsement of Governor Polis, demonstrating how smart policy can expedite the clean energy transition and cut customer costs while keeping utilities profitable.

However, far more financial tools exist. A series of research briefs from America's Power Plan outlines these tools and provides options for any analysis of potentially uneconomic coal-fired generation.

Analyzing publicly available financial information can help policymakers and utility stakeholders identify where running existing generation (particularly older, less efficient coal-fired plants) costs more than replacing it with wind or solar. When building renewables is cheaper than operating existing coal, swapping "steel for fuel" adds value for investors, customers, and the environment.

Modifying depreciation schedules and early plant retirements are important tools for transitioning away from older assets, such as coal plants, to cheaper resources such as wind and solar. And finally, when electric utilities transition from fossil fuels to clean energy, they can address unrecovered investment balances through debt for equity refinancing.

Time to get ahead of the looming coal closure wave

Despite unsuccessful federal efforts to subsidize uneconomic coal generation and roll back air pollution regulations, clean energy technologies keep improving and falling in cost, meaning coal's biggest threat will forevermore be economics and not regulations.

Policymakers must now start planning for a massive turnover of U.S. electricity generation from coal to clean, requiring a true accounting of which clean energy resources can replace existing coal plants.

Every passing day that regulators and utilities fail to wake up to the new clean energy reality locks in higher customer costs, deeper economic risks, and more emissions that cause climate change. It's time to start the coal-to-clean transition.

**Xcel Minnesota: Running coal seasonally will save customers millions, reduce emissions**

*By Catherine Morehouse – Utility Dive, January 8, 2020.*

Dive Brief:

**Xcel Energy Minnesota wants to run some of its coal under economic and seasonal dispatch instead of through self-scheduling practices**, it told state regulators in December.

The utility submitted a filing with the Minnesota Public Utilities Commission (PUC) to **begin offering its two remaining coal plants seasonally into the Midcontinent Independent System Operator** (MISO), **rather than self-committing the plants to the market, which leads to market distortions**, according to research from the Sierra Club and the Union of Concerned Scientists (UCS). The move is part of an ongoing proceeding opened by state regulators in November, and several clean energy groups in the state have been pressing the utility to consider moving away from self-scheduling.

The measures are **estimated to reduce customer costs by tens of millions of dollars and 5 million tons of carbon emissions annually** by optimizing use of the plants. **Minnesota's PUC was the first state commission in the country to open up a docket on this issue**, according to UCS Senior Energy Analyst Joe Daniel, whose research implies the market distorting effects of self-scheduling are widespread across regional power markets.

Dive Insight:

**Xcel's filing with state regulators shows clear environmental and economic benefits to seasonally dispatching its coal units, and those results would likely be magnified if utilities across the country did the same thing**, according to Daniel.

"Extrapolate [Xcel's results] out to the US Coal fleet and we are talking about a double-digit reduction in US electric sector emissions overnight while simultaneously reducing energy costs to customers," he said in a Tweet Tuesday.

Based on preliminary results from Daniel's research, Xcel subsidiary Northern States Power Company is the third worst offender in the MISO region, in terms of potential cost savings from operating plants more effiiciently.

The company asked regulators to approve economic and seasonal dispatch of its 511 MW Allen S. King plant and Sherco Unit 2, which accounts for 682 MW of the facility's over 2.2 GW of capacity. Xcel will operate those facilities based on market signals rather than self-scheduling during non-peak seasons, unless the plant is needed for reliability. The Allen plant will begin these operations in March and the Sherco unit in September of this year.

"We expect seasonal operation of our coal units will reduce carbon emissions, save our customers money and we will continue to study how this type of operation affects the rest of our system to ensure reliability," Xcel told Utility Dive in an emailed statement.

Xcel will save anywhere from $8.5 million to $28.5 million annually on fuel costs for these units, based on the utility's modeling. Over the lifetime of the proposal, which would last until Sherco Unit 2's retirement in 2023 and the Allen Plant's retirement in 2037, the facilities would save $18.4 million in total operation and maintenance costs. King would also save over $27 million in capital costs over those nine years.

**The utility's results "validate a lot of what has been raised by UCS and Sierra Club,"** Senior Director of Energy Markets and Regulatory Affairs at Fresh Energy Allen Gleckner told Utility Dive. "And then what we've been seeing in our work in advocacy is that this is a real opportunity, and I think these numbers in this proposal show that there's an opportunity for change."

**Under self-committing practices, utilities run their units on a scheduled basis, which can distort market prices if the units production costs are higher than how much power is selling for that day.**

**In some cases, utilities self-schedule in order to avoid the high costs of powering up and shutting down units, which traditionally run as baseload. But low-cost solar, wind and natural gas mean that coal is less economic more often, which is causing utilities and regulators to take a harder look at resource scheduling,** prodded by clean energy groups.

"The increasing levels of renewables on our system and across the MISO footprint are impacting the wholesale energy markets, and we expect those impacts to increase as more renewables are added," Xcel said in its filing. "Wind and solar resources provide energy to the grid without fuel costs and have a dispatch cost of zero, or a negative price. … In response to the changing market dynamics … we are proposing to implement **seasonal operations**."

**The Southwest Power Pool's independent market monitor is the only one to have run a full market evaluation, which found self-committing power was suppressing the market's clearing prices by about $2/MWh.**

**Sierra Club research examining the MISO market found self-scheduling practices suppressed market prices by about $7.70/MWh and without it coal generated power would be reduced 10%.**

MISO's market monitor has not run a full analysis on the impacts of self-scheduling, but MISO itself has developed a multi-day operating margin forecast to help mitigate the issue and "guide more economic generation start and stop decisions," the grid operator told Utility Dive in October.

There is also a docket open to examine the issue with Minnesota's other two investor-owned utilities, Otter Tail Power and Minnesota Power. Those utilities will file an informational compliance filing in March.

"I think that there's a good opportunity for those other utilities to, if not do the exact same thing, to take a really hard look at some of these changes," said Gleckner.

**Texas muni to shut Gibbons Creek coal plant for most of the year**

*By Peter Maloney – Utility Dive, 07.24.2017*

Dive Brief:

**The Texas Municipal Power Agency (TMPA) told the Electric Reliability Council of Texas (ERCOT) that it plans to operate the 470 MW coal-fired Gibbons Creek power for only five months of the year.**

TMPA said **it is not economical to run the plant** in Anderson, Texas, **except during the hottest months, from June through September**. The agency must sell the plant by Sept. 2018 or its board will have to decide whether to shutter it completely.

TMPA says the plant **cannot effectively compete with generation fueled by low cost natural gas and against an influx of wind power** in ERCOT, a trend the grid operator expects to push up to 10 GW of coal-fired generation offline by the next decade.

Dive Insight:

In ERCOT, the absence of a capacity market means energy market prices can reach up to $9000/MWh during peak demand events, making it profitable to operate some plants for only part of the year.

But a recent influx of wind generation is cutting down on the frequency of those episodes, and better economywide efficiency is denting overall demand growth. Despite occasional price spikes from hot weather, ERCOT says the Texas grid has sufficient capacity to meet summer loads. Total generation is about 82,000 MW, against a summer peak demand forecast of about 73,000 MW.

As renewables increase the need for fast-ramping generation, less flexible coal plants are running less. A report released last September by the Institute for Energy Economics and Financial Analysis showed average capacity factors for major ERCOT coal plants in 2015 were significantly lower than in previous years. Gibbons Creek was one, with Platts noting its factor dipped to 39% this year after averaging 86% between 2004 and 2008.

The IEEFA report found that coal generated 39% of the electricity in ERCOT in 2015, but only 24.8% as of May 2016. By 2031, ERCOT expects 10 GW of additional coal retirements as solar increases to 17% of its generation portfolio.

TMPA has been trying to sell the Gibbons Creek plant and struck an agreement with the privately held Clean Energy Technology Association last year. But the sale effort has not been going well and there are no pending sales or attractive offers, TMPA told local news outlet KBTX.

In May, the municipal members of TMPA agreed to waive a Sept. 2017 deadline for the sale, allowing for more negotiation time. If the plant does not sell by Sept. 2018, the agency could face up to $40 million in decommissioning costs, according to the Denton Record-Chronicle.

The cities of Bryan, Garland, Denton, and Greenville make up the Texas Municipal Power Agency.

**SWEPCO announces coal mine layoffs for 2019**

*By Jeff Ferrell - KSLA News 12, 12.04.2018*

SHREVEPORT, LA (KSLA) - We have some good news, bad news to report on the economic front.

First the good: **SWEPCO and CLECO Power customers are expected to save a total of $85 million by the end of 2020.**

Now the bad: To help make those savings a reality about half the workforce will be laid off in the next year at a lignite mine in Red River Parish.

In the Coushatta area of Red River Parish word that the Dolet Hills Lignite Mine will be losing roughly 135 workers in the next year has been a reaction of concern and sadness.

Those layoffs of SWEPCO employees at the Oxbow Mine are taking place because the year-round operation will soon drop from 3 of those giant dragline machines down to 1.

“We’re going to transition to the single dragline starting in early 2019. And we’re in the middle of a re-staffing process,” explained SWEPCO Spokesperson Carey Sullivan.

“So, we’ll identify what positions will be reduced and all those employees will be offered a severance program through SWEPCO and through AEP.”

**The lignite mined at the Oxbow Mine fuels the CLECO Dolet Hills Power Station near Mansfield.**

**But the high cost of mining lignite at Oxbow, along with the low market price of power, mean the station will transition from generating electricity year-round to seasonal, during the hottest months when demand is highest, from June to September.**

The silver lining: A CLECO spokesperson told us that none of their employees will be laid off. But for local residents, word of lost jobs is a big blow to the economy.

That included Brandon Williams who said, “People are desperate for jobs now, you know. People are trying to make it out here.”>

**As for the bottom line in saving customers money, A CLECO spokesperson said their customers alone will save about $35 million by the end of 2020.**

**And when you combine that figure with the estimated savings for SWEPCO customers, it comes to as much as $85 million.**

Sullivan added that there will likely be two waves of reductions in those SWEPCO Oxbow Mine employees, one early in 2019 and the other later in the year.

**PacifiCorp to Reduce Jim Bridger Output to Meet Wyoming Haze Plan**

*By Steve Ernst – Clearing Up, 09.06.2019*

**PacifiCorp will dial back the output from Jim Bridger 1 and 2, rather than install pollution control equipment needed to comply with Wyoming's regional haze implementation plan.**

The Wyoming Department of Environmental Quality agreed Aug. 23 to allow the utility to meet the state haze reduction rules with an alternative strategy that will **limit the capacity factor for all four coal-fired units at Bridger to 76.3 percent**, and allow the utility to **forgo a capital investment of over $300 million to install selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) equipment** on units 1 and 2.

In a filing, known as a Reasonable Progress Determination, PacifiCorp said the annual cost of installing SCRs, SNCRs, and the Reasonable Progress (RP) Determination Assessment would annually cost $34.8 million, $9.4 million, and $2.1 million, respectively, using a depreciation schedule of 2037 for units 1 and 2.

"Considering the expected remaining useful life of the Jim Bridger plant, neither Jim Bridger Unit 1 nor Unit 2 is expected to operate long enough to justify SCR or SNCR installation," the utility said in the filing.

Under the RP Reassessment, the potential annual CO2 emissions from the Bridger plant would be 16.8 million tons per year, a decrease of 1.7 million tons/year as compared to current operations. The plant would use 8.6 million tons of coal annually using a capacity factor of 76.3 percent, compared to 11.3 million tons annually currently.

PacifiCorp's plan will reduce average annual mass emissions of haze-causing sulfur dioxide plus oxides of nitrogen by nearly 20 percent.

The plan sets a monthly "block-pound-per-hour" of NOx and SO2 emission limits for all four units, according to the filing with DEQ, and set a 12-month rolling limit of 17,500 tons.

"This combined set of lb/hour and tons/year limits will be enforced in lieu of installation of selective catalytic reduction technology on Units 1 and 2, and will effectively decrease the operating capacity of the plant, thereby reducing its emission of haze-causing pollutants," a DEQ document states.

Installation of SCR controls on Jim Bridger units 3 and 4 were completed in 2015 and 2016; units 1 and 2 were scheduled to have the equipment installed in 2022 and 2021, respectively.

**"We believe this is a compelling case for compliance with regional haze rules, in a meaningful way across a range of environmental concerns, at a much more**

**reasonable cost for our customers," Dave Eskelsen, spokesman for PacifiCorp**, told Clearing Up.

PacifiCorp continues to perform modelling for its 2019 integrated resource plan, which includes reviewing the economic costs and reliability issues associated with potentially closing some of its coal units early.

A economic analysis released in December showed that roughly 60 percent of PacifiCorp's coal units could potentially be retired in 2022 and replaced with renewables or natural gas-fired generation (CU No. 1880 [14]).

Bridger Unit 1 appeared several times as part of a cluster of plants in Utah, Colorado and Wyoming that showed the largest potential benefits of early retirement.

Closing Naughton units 1 and 2 and Jim Bridger Unit 1 in 2022 would yield a benefit of $301 million in present value of revenue requirement.

Shuttering Naughton 1 and 2, Hayden 1 and Bridger Unit 1 in 2022 would create $307 million in PVRR savings.

Retiring Naughton 1 and 2, Hayden 1, Bridger 1 and Craig 2 in 2022 yielded $317 million in PVRR savings.

The 2019 IRP is scheduled to be filed on Oct. 18.

**The Billion-Dollar Coal Bailout Nobody Is Talking About: Self-Committing In Power Markets**

*By Joe Daniel[1] and Mike O'Boyle[2] – FORBES. May 28, 2019*

**Nearly two-thirds of the United States' power plants operate in competitive wholesale markets. Market rules typically prescribe that only the cheapest set of resources may run—nowadays, those are often renewable energy resources. Despite a growing trend of coal losing on cost to renewables and natural gas, coal generation remains a dominant player in many of these markets.**

**New research** by Union of Concerned Scientists Senior Energy Analyst Joe Daniel uncovered the fact that **coal plants in "competitive" wholesale electricity markets were being run uneconomically**, meaning they accrued significant losses for months at a time. This behavior defied economic logic, but **could be explained by regulation**. These plants are owned and operated by vertically-integrated utilities (companies that own their generation sources and directly serve retail customers in an area without alternative suppliers), who receive cost recovery for expenses related to these coal plants under regulatory approval outside of the market.

To investigate the size of the problem, Joe analyzed wholesale electricity market data to better understand what drives investment in fossil fuel and clean energy power plants in those markets. **Much of this market distortion was happening for plants owned and operated by vertically-integrated utilities which are permitted to "self-commit" their coal plants, forcing them to run at above-market costs**. In this way, **regulation functions as a subsidy to keep coal plants running, and customers are on the hook**.

Energy Innovation's Director of Electricity Policy Mike O'Boyle interviewed Joe to learn why this is happening, the risks of this practice, and what it means for consumers and clean energy's future in these markets.

**Mike O'Boyle: Can you explain what you mean by coal self-committing?**

Joe Daniel: Most people think the system operators that coordinate competitive power markets are centralized decision-makers for the electricity grid. That's true, in theory. In practice, it's a bit more complicated. Market rules give participants like utilities and power plant owners a great deal of decision-making authority. For instance, power plant owners can decide when to make their resources available, then offer those resources into the market for others to purchase.

Some owners allow the market to "commit" their resource by specifying what price and output level they are willing to operate at. Market committed resources allow market forces to drive increases or decreases output, or turn off units entirely. In aggregate,

[1] Joe Daniel is a senior energy analyst with the Climate & Energy program at the Union of Concerned Scientists.
[2] Mike O'Boyle is Energy Innovation's Director of Electricity Policy.

these economic bids provide the system operator with enough information to choose the power plants that minimize overall system costs.

However, market participants can bypass this process by self-committing the unit, essentially superseding the market operator's decision of whether to run that plant. Instead, power plant owners can tell the market that the unit must remain on, which requires that it operate at some minimum level of output. Barring an emergency, the operator can't tell the unit to turn off even if there's cheaper energy available on the market.

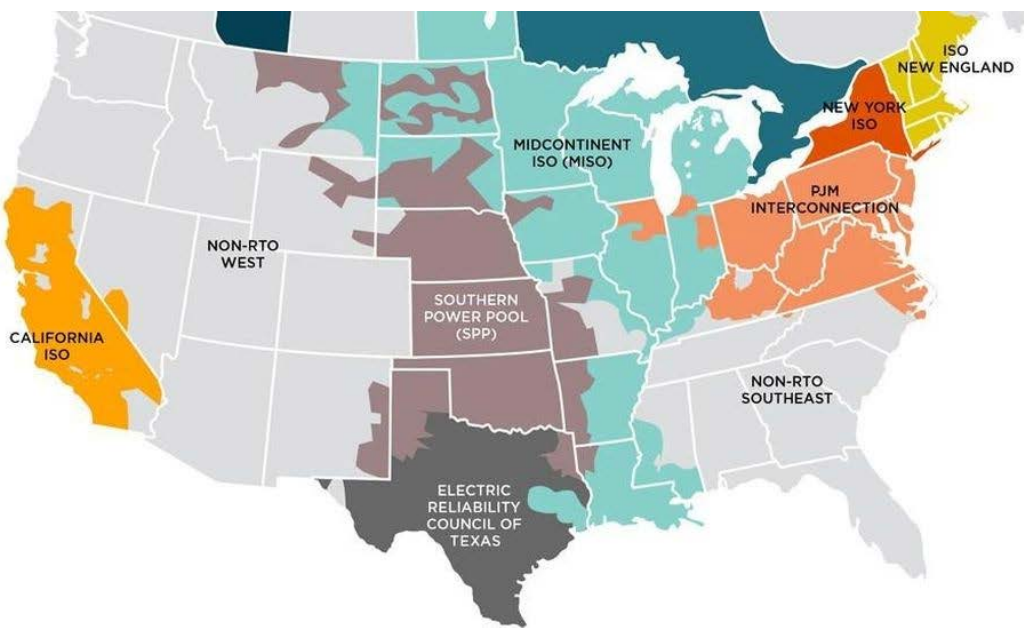
**MO: Please explain how you figured out that self-committing is happening.**

JD: A few years back, I was working on a utility proceeding within the Southern Power Pool (SPP) organized market with a lawyer who noticed that the utility's coal plant, which previously operated at a high capacity factor, suddenly stopped running. The lawyer and I eventually discovered that the utility-owner had changed its operational paradigm from "self-commitment" to "market-commitment."

So, I began researching self-commitment, market rules, and hourly coal plant operations across the country to understand why coal plant operators were running at seemingly illogical times, based on the low prices for solar, wind, and other sources in these markets. Originally, my focus was on SPP, but I quickly expanded my analysis to the Midcontinent-ISO (MISO), PJM Interconnection, and Electric Reliability Council of Texas (ERCOT) competitive energy markets, too.

**MO: How many coal plants did you examine and where are they located?**

JD: Most recently, I completed an analysis screening every coal-fired power plant that operates in PJM, MISO, ERCOT, or SPP, roughly two-thirds of all existing U.S. coal plants.



RTO/ISO markets in the United States

Roughly 100 gigawatts (GW) of coal, or nearly half of the coal in organized markets, received additional scrutiny that included analyzing hourly coal plant revenues. These coal plants operated at a loss for *at least* one month during the study periods; even worse, customers were footing those bills.

Compared to SPP and MISO, PJM and ERCOT had fewer, but still, some bad actors who engaged in self-committing to the detriment of their customer's wallets.

**MO: What has your research on self-committing shown?**

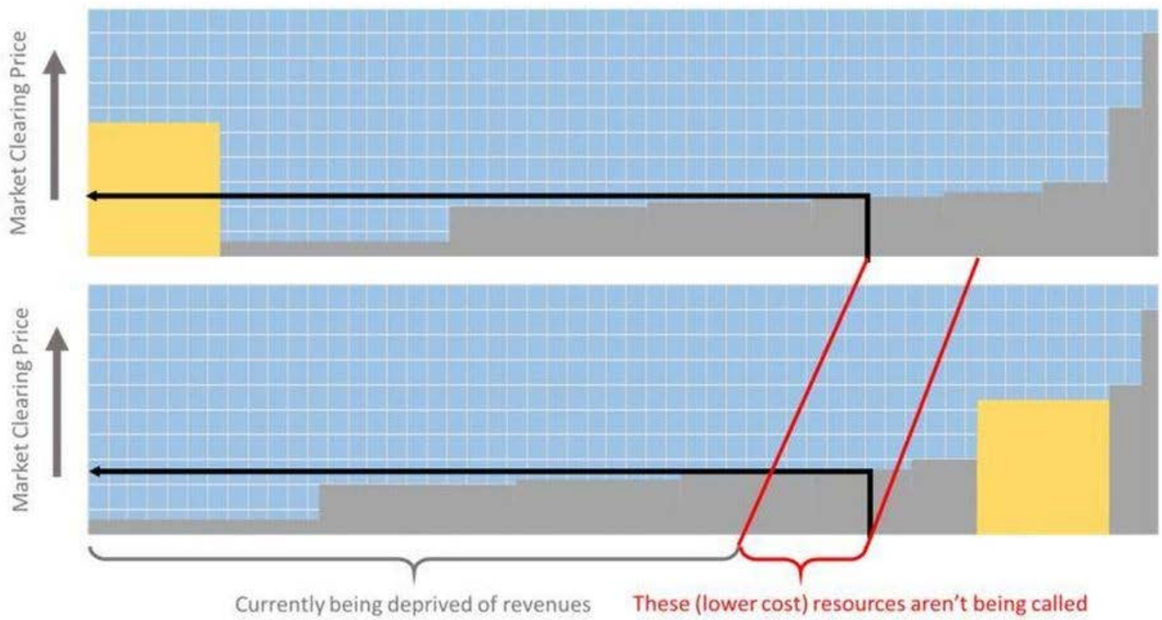
JD: This opaque practice undertaken by coal plant owners hurts customers and contributes to climate change. My analysis indicates that self-committing uneconomic coal costs consumers an estimated $1 billion dollars a year in the regions I evaluated. But I also found that not all coal plant owners engage in this inefficient practice. Rather, the worst offenders are vertically integrated utilities that can lose money in the competitive market and then recover those losses on the backs of retail customers, including those most economically vulnerable to higher electricity costs. Customers of vertically integrated utilities are "captive"—they have no choice but to accept these costs.

My research is ongoing, so it is hard to say with precision what the cumulative environmental impacts are of coal plants that operate like this, but it's not good. Statistically, an uneconomic coal plant would be replaced by either (a) emissions-free wind energy; (b) a natural gas plant that, while not clean energy, has lower emissions rates than coal; or in a worst-case scenario, (c) a more efficient coal plant with marginally lower emissions rates.

**MO: How does this practice affect renewables in wholesale electricity markets?**

JD: Markets are supposed to ensure that all power plants are operated from lowest cost to most expensive. Self-committing allows expensive coal plants to cut in line, pushing out less expensive power generators such as wind, depriving those units from operating and generating revenue.

The practice of self-committing also reduces market revenues for all the generators that do get called. Wholesale electricity prices are set by the marginal cost of supplying one unit of energy – the most expensive power plant selected by the operator sets the price. In the absence of self-committing, this price for energy would increase, raising revenues for all selected power plants.




**Coal plant self-committing reduces market revenue for all generators.**

Properly functioning markets are predicated on properly functioning price signals. If the market prices are distorted, then what happens to the market? Nothing good.

**MO: You've called self-committing coal a hidden coal bailout. What do you mean by this, and how does it compare to state subsidies for renewable energy?**

JD: Self-committing is regressive, reducing the efficiency of our electricity grid, exploiting customers, and exacerbating emissions when coal plants run more. It also artificially distorts market prices to favor aging technology while limiting investments in low-priced renewables.

On the other hand, renewable subsidies are policy decisions that are proposed, scrutinized, and enacted by democratically-elected representatives. Consequently, the policies—whatever their strengths and weaknesses—are at least the product of a transparent, intentional process, and those who put them in place are accountable for the subsidies' effects. But that's not what we have with self-committing.

**MO: Is self-committing coal happening in any states with clean energy goals? If so, is it undermining the energy transition?**

JD: Yes and yes. Minnesota, for instance has set clean energy goals yet has uneconomic coal plants self-committing in the MISO market. This reduces grid flexibility and may force wind farms to curtail output because the electric grid is essentially zero-sum. If a coal plant is finagling the market to take the electricity it produces, it is preventing some other unit from providing that electricity. That might be a wind farm. It might be a gas plant. Regardless, it is hurting consumer pocket books and our health.

**MO: What can be done about self-committing coal plants?**

JD: Self-committing is a choice the utilities are proactively making. In some markets, this is as simple as selecting a different drop-down option. Power plant operators simply have to change their bidding behavior when offering their power plant into the market, which would allow the market operator to more efficiently run the whole system.

Alternatively, utilities could choose to seasonally operate the plants they own, similar to the strategy taken by owners of several coal plants in Texas and Louisiana. Just this past winter, Cleco and AEP subsidiary SWEPCO announced that Louisiana's Dolet Hills coal facility will switch to operating only four months of the year. The utilities' own estimations indicate this will save its customers $85 million by the end of 2020.

State regulators have tremendous influence over the utilities they oversee. They can't assume the controls of power plants but can create incentives or penalties to ensure utilities behave better.  In some states like Washington, Oregon, and Montana, regulators have come up with a better mechanism to allow for cost/profit sharing that aligns price incentives. Alternately, a regulator can disallow the costs associated with running a power plant uneconomically, forcing investors to take a loss rather than forcing customers to bail out those plants.

Staff/202
Enright/19

Minnesota House of Representatives

Feb 18 2020 3:31PM

# ‘Coal holiday bill’ would make seasonal shutdowns possible

By Rob Hubbard

What would happen if coal-burning electricity plants shut down during the spring and fall, when demand is lower? That’s what Xcel Energy wanted to know, so, in December, it asked the Public Utilities Commission if it could find out.

But it’s unclear in state law whether such a pilot project is permissible.

It would be under HF3209.

Sponsored by Rep. Zack Stephenson (DFL-Coon Rapids), the bill would require utilities to analyze the economic and environmental costs and benefits of seasonal shutdowns of their nonrenewable energy sources.

At Tuesday’s meeting of the House Energy and Climate Finance and Policy Division, the bill was laid over for possible inclusion in an omnibus energy and climate bill. It has no Senate companion.


Rep. Zack Stephenson

Stephenson calls it the “Coal Holiday Bill,” and the impetus for it came from Xcel, which wanted to idle a pair of plants in the spring and fall. According to its filing with the Public Utilities Commission, that would save customers an estimated $55 million over a three-year period.

“The old model for these coal power plants is that they needed to essentially run all the time to be an economic proposition,” Stephenson said. “But there’s substantial evidence that ratepayers can save significant amounts of money if plants are idled, particularly in the spring and fall, when load is lower and there’s less demand. … This bill is about providing utilities with the option of being able to take advantage of those savings.”

Stephenson said the bill features what he called a “show your homework” section, in that utilities would be required to explain how seasonal shutdowns would make economic sense for them.

Isabel Ricker, senior policy associate for Fresh Energy, said, “Xcel’s analysis shows that this would save customers between $90 million and $130 million over nine years, and reduce carbon dioxide emissions by 65%.”

Rick Evans, director of regional government affairs for Xcel Energy, also spoke in support of the bill.

“You do your modeling, and you come out with an idea of how this might work,” he said. “But we really don’t know until we try it. This will give the PUC the authority to approve this kind of dispatch and provides enough safeguards.”

Two amendments offered by the division’s Republican lead, Rep. Chris Swedzinski (R-Ghent), were defeated. But they started a conversation that continued through two other bills, which propose requiring utilities report to customers on electric generation sources and renewable energy programs: That they could result in significant work and expense for small rural and municipal electrical cooperatives.

**Are old Midwest coal plants pushing renewables offline?**

*Jeffrey Tomich - E&E News, Energywire 06.11.2019*

**Regulators are looking at whether coal plants are running when cheaper, cleaner options are available.**

Midwest regulators are **probing whether a little-known practice** is slowing the region's accelerating pivot away from coal toward renewables and gas.

Utility commissions in Minnesota and Missouri are looking at the way companies run older coal plants, even when those units aren't the cheapest option — **and whether that's squeezing out lower-carbon resources and raising costs for consumers**.

The **Minnesota Public Utilities Commission asked the state's investor-owned utilities for data earlier this year on the practice of "self-committing" and "self-scheduling"** generating units in the Midcontinent Independent System Operator (MISO) grid.

Similarly, the **Public Service Commission in Missouri**, which includes parts of MISO and the Southwest Power Pool (SPP), **unanimously voted to open a similar case last week** after Commissioner Daniel Hall asked whether the practice is benefiting the state's ratepayers.

Hall said the issue is worth a close look, noting that MISO and SPP — as allowed under existing tariffs — have 78% and 31% of their energy self-committed, respectively.

"From what I understand, that is squeezing out some, perhaps, lower-cost generation, particularly gas in the short run, but possibly renewables in the long run," Hall said.

Regional transmission operators such as MISO and SPP are tasked with keeping the lights on at the lowest cost, and they prefer to dispatch the cheapest generating units before running more costly ones.

But under grid operator tariffs, utilities can ensure generating units run at a designated output level even with less costly units available and accept the prevailing market price. In such cases, plants are price takers and accept the prevailing wholesale energy price.

**The utility process of self-committing or self-scheduling power plants to run even when there's cheaper energy available on the grid is a complex issue and opaque to outsiders. Increasingly, there are questions about whether it's slowing a transition to cleaner energy amid inexpensive shale gas and falling costs for renewable energy.**

For Joseph Daniel, a senior energy analyst at the Union of Concerned Scientists, there's little doubt.

Daniel has analyzed the coal fleet throughout MISO, SPP, the PJM Interconnection and the Electric Reliability Council of Texas. About half of it, or 100 gigawatts, ran more than expected based on economics.

In a recent blog post, he said the practice is costing consumers in those regions $1 billion a year.

Of the 100 GW, "every coal plant I looked at operated uneconomically for at least a month," he said. "Some of the worst actors operated uneconomically every month."

*Receiving value or getting 'fleeced'?*

Utilities and grid operators dismiss any notion that consumers are being shortchanged.

Bruce Rew, vice president of operations for Little Rock, Ark.-based SPP, said determining whether self-commitment of generating units into the day-ahead markets provides a net value to consumers requires taking a longer-term view of the issue.

"The total cost and value that the self-commits bring are more than just looking at a simplistic view of the energy side of it," he said.

The simplest example of why units are self-committed to run is nuclear plants, Rew said.

"They are averse to being turned off and on," he said. "So a nuclear unit in our market is self-committed."

While Rew defended the practice for nuclear plants in SPP, the bulk of self-committed plants in the region burn coal. **In some instances, generating units may have contracts that require them to burn a certain amount of fuel.**

**In other cases, they may have high startup costs that preclude them from being shut off and restarted over a 24-hour period.**

Over a longer period, however, units may be economical.

"It may be a really cheap-energy unit, but we wouldn't commit it because of the high startup cost," Rew said. "So a unit like that would need to self-commit so that they can get into the market so they can deliver this cheap energy."

Rew said the share of energy from generating units that self-commit has fallen over the past couple of years because of changes in market rules.

MISO, meanwhile, is "tracking this industry-wide discussion with our stakeholders and monitoring state proceedings on the issue," spokeswoman Julie Munsell said in an emailed statement.

The Midwest grid operator is also examining how it can "enhance visibility" into the anticipated capacity needs for multiple days to better assess the longer-term economics of units with high startup costs.

**In Minnesota, the PUC asked investor-owned utilities for three years of data, including the amount of energy self-committed or self-scheduled and the difference between production costs and market prices.**

Each utility defended self-committing or self-scheduling generating units given the limitations of grid operator rules.

Minnesota Power said in a filing with the PUC that self-scheduling of its 1,000-MW Boswell coal plant has reduced customer costs in 2017 and 2018 by a total of $23 million. At certain off-peak hours, there was a net cost to customers, the utility said.

Xcel Energy Inc. likewise said market revenue from self-commitment of Minnesota nuclear and coal plants exceeded the plants' production costs by more than $500 million over the last two years.

Xcel said the data "represents an appropriate metric for determining whether the company's self-commitment decisions were beneficial and ... demonstrates that the company's customers received value as a result of its decision to self-commit the baseload resources."

Minneapolis-based Xcel also said that MISO's rules under which generating units are committed 24 hours at a time can result in "potential uneconomic cycling of units with long lead times or high startup costs."

**In its order last week, the Missouri PSC has given utilities until June 28 to provide data, and the commission staff will produce a report by mid-August.**

Although it's yet unclear what regulators in Minnesota and Missouri will do with the information they're gathering, Daniel of UCS said he is encouraged to see regulators asking questions.

**"Commissions are uniquely positioned to navigate this issue," he said. "It has implications for transmission planning, it has implications for emissions and how we value renewable resources. But first and foremost, it's about consumers being fleeced."**

**Missouri regulators vow to keep closer eye on power plant 'self-scheduling'**

*By Karen Uhlenhuth – Energy News. September 17, 2019*

**Investor-owned utilities will need to disclose when they operate power plants despite low wholesale market prices.**

**Missouri will require investor-owned utilities to share information on how often they sell power to wholesale markets for less than what it costs to generate.**

A recent study by the Union of Concerned Scientists estimated the practice, known as "self-scheduling," costs ratepayers nationally at least $1 billion a year.

The impact on Missouri consumers isn't known, but state regulators vowed to keep a closer eye on the issue and haven't ruled out further reforms.

**"The amount of self-scheduling will be evaluated, and the impact on ratepayers will be explored,"** Missouri Public Service Commissioner Daniel Hall said.

The move last month was praised by clean energy advocates, who claim utilities have used self-scheduling as a way to prop up uneconomic coal plants.

"Very few states are looking into this. Missouri is on the forefront," said Casey Roberts, a senior attorney for the Sierra Club who offered testimony in the case.

Utilities are permitted to self-schedule, or self-commit, some power to the wholesale market, but the practice has come under the microscope in recent years. It's been discussed among members of the Southwest Power Pool and the Midcontinent Independent System Operator.

In February, the Minnesota Public Utilities Commission ordered three investor-owned utilities to begin submitting an annual analysis on self-scheduling and associated costs.

Joe Daniel, a senior energy analyst with the Union of Concerned Scientists, has studied the issue extensively and contends that it runs counter to the goal of reliable power at the lowest possible price, which is at the heart of the wholesale power-sharing marketplace.

Under the wholesale day-ahead market system, utilities each day tell the grid operator how much power they will have available each hour of the following day from which sources, and the price they want to be paid for their megawatts. They also specify how much power they will need to purchase.

The grid operator selects enough sellers to cover anticipated demand, choosing the cheapest sources first. In recent years, as wind generation has increased — and its price tumbled — coal-fired power has become ever less competitive, leaving offers of coal-fired power on the table.

Enter self-commitment. Rules in the wholesale energy marketplace allow utilities to require that a certain amount of power be sold at the day's going price, regardless of whether that price covers the utility's cost of generation.

If, for example, a utility's cost to produce power in a coal-burning plant is $30 per megawatt, but the utility offers to sell it for $25 per megawatt in order to ensure that it sells, the generating utility will lose $5 per megawatt if it proceeds to self-commit. Generally, it will then try — often with success — to persuade state regulators to allow it to recoup the difference from customers.

Selling coal-fired electricity for less than the cost to generate it likely will look less attractive to Missouri utilities once they start disclosing the details of the practice to regulators, Daniel said.

"This is an issue for which sunshine will be a great disinfectant," he said. "The more utilities know that their regulator is scrutinizing their practice, the more likely they're going to engage in better behavior."

**Going forward, Missouri utilities may not be able to recoup fuel expenses, depending on the information they disclose about self-commitment practices.**

**Utilities say there are legitimate reasons for requiring the sale of their power on the wholesale market, even when it will be a financial loss for the company. In explaining the decision to self-commit, Kansas City Power & Light said in a document filed with regulators that repeatedly starting up a coal plant can create significant wear on machine parts. The company sometimes will self-commit a plant to minimize that, especially if it anticipates that its power will be needed — and earn a profit — a day or two into the future.**

**Utilities also sometimes self-commit plants if they need to test them after repairs or to ensure they meet government environmental standards.**

Missouri commissioner Hall agreed that "there are some good reasons for units to self-commit. My **concern is that … self-commitment may go beyond those good reasons**."

State commissioners are in a "unique position" to appraise and possibly rein in self-commitment, said Daniel, of the Union of Concerned Scientists. They are charged with determining whether utility expenditures are "prudent," and have the authority to refuse to bill customers for company expenses they consider imprudent.

"I'd argue that operating expenses to run a coal plant when lower-cost resources were available on the market is imprudent," Daniel said.

**Steve Gaw, a former Missouri utility commissioner and legislator who now is a policy director for the Advanced Power Alliance**, said, **"Looking at these issues is something commissions should be doing."**

The finances of running power plants is “a complicated issue and it can be challenging to sort through,” he said. “In the past, I don’t believe there’s been any scrutiny.”

**Four Colorado power providers to join the California Western Energy Imbalance Market**

*New release from Black Hills Energy – 12.17.2019*

DENVER, Colorado – **Four Colorado utilities announced today that they plan to join the Western Energy Imbalance Market** (WEIM), operated by the California Independent System Operator (CAISO), to save customers money while allowing them to use more energy from wind and solar.

**Xcel Energy, Black Hills Colorado Electric, Colorado Springs Utilities and Platte River Power Authority** have different business models, customers and geography, but all share a commitment to leading the clean energy transition and believe the WEIM will provide the most benefit to their collective Colorado customers.

An energy imbalance market is a real-time market in which energy generation from multiple power providers is dispatched at the lowest possible cost to serve the combined customer demand of the region.

Earlier this year the utilities commissioned The Brattle Group to study the WEIM and the Western Energy Imbalance Service (WEIS) proposed by the Southwest Power Pool (SPP).

The study concluded that as the larger of the two markets, the WEIM offers greater potential to lower production costs due to the size of its market footprint and the diverse resources available within the WEIM. The WEIM also offers lower administrative costs and participants of the WEIM are exploring adding day-ahead market services. Day-ahead market services are designed to help utilities plan which resources they will use to generate energy, allowing more renewables to be integrated into the system.

Currently, Xcel Energy, Black Hills Colorado Electric and Platte River Power Authority share resources and balance demand for electricity through a joint dispatch agreement (JDA) that has reduced costs for customers. In March 2020, Colorado Springs Utilities will begin participation in this joint dispatch agreement. Joining the WEIM will allow the group to exchange energy with an even larger group of neighboring utilities and help integrate more clean energy into their systems.

“This decision is an important next step in our efforts to keep our customers’ bills low and provide more 100 percent carbon-free energy like wind and solar,” said Alice Jackson, president of Xcel Energy Colorado. “We are pleased to continue this regional collaboration of investor-owned utilities and public power agencies to benefit our customers, the environment and support the state of Colorado in achieving its clean energy goals.”

“By joining with our regional utility partners in this effort, we have the opportunity to create value for our customers,” said Vance Crocker, vice president of Black Hills Colorado Electric., doing business as Black Hills Energy. “We’re very supportive of a plan that will lead to lower energy costs and more renewable energy options for our customers and communities."

"We've created excellent partnerships though the JDA that currently provide great value to our owner communities," said Jason Frisbie, general manager and CEO of Platte River Power Authority. "Joining an EIM will expand the regional collaboration among all partners to the benefit of every Colorado customer we serve."

"We are committed to offering our customers clean, more diverse and affordable energy," said Aram Benyamin, Colorado Springs Utilities CEO. "This regional partnership provides us the opportunity to integrate more renewable energy into our system at a lower cost."

"The California ISO is pleased that Xcel Energy, Black Hills Energy, Colorado Springs Utilities and Platte River Authority have announced their intent to join the Western EIM," said ISO President and CEO Steve Berberich. "The outstanding results the Western EIM has achieved over the last several years demonstrates the valuable benefits and cost savings we achieve when we work together to meet consumer needs in an evolving energy industry."

Over the next few months, the group will be working with the ISO to finalize the implementation agreement and settle on a potential date to join the market, with a target of 2021.

WESTERN ENERGY IMBALANCE MARKET

California ISO

# News Release

For immediate release | **April 30, 2020** **Media Email** | **ISOMedia@caiso.com**

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## Western Energy Imbalance Market gross benefits exceed $900 million

### Nine balancing authorities share $57.9 million in first-quarter benefits for 2020

FOLSOM, Calif. – The Western Energy Imbalance Market (EIM), the real-time energy market operated by the California Independent System Operator (ISO), reports generating $57.9 million in first-quarter gross benefits, putting the total at $919.69 million since 2014.

The Western EIM uses advanced technology to find and deliver the lowest-cost energy to utilities throughout the West while enhancing reliability.

The following table shows the Q1 2020 benefits by participant. New entrants, Salt River Project and Seattle City Light, are not listed, as their participation started in the second quarter of 2020.

| | *(millions $)* |
|---|---|
| Arizona Public Service | $11.26 |
| BANC | $7.07 |
| California ISO | $9.57 |
| Idaho Power | $5.15 |
| NV Energy | $5.36 |
| PacifiCorp | $7.80 |
| Portland General Electric | $6.93 |
| Powerex | $1.09 |
| Puget Sound Energy | $3.67 |
| **Total** | **$57.90** |

In addition to the economic results, the total greenhouse gas emission reductions since 2014 is 470,245 metric tons, the equivalent of removing 98,867 passenger cars off of the roads.

Because of the renewable energy transfers facilitated by the Western EIM, there was a reduced need for renewable curtailments during periods of oversupply. The avoided renewable energy curtailment for the quarter was 86,740 MWh, resulting in a total of 1,098,890 MWh since 2014.

Over the next two years, the Western EIM will experience one of its largest expansion periods with the participation of Los Angeles Department of Water and Power, NorthWestern Energy, Turlock Irrigation District, Public Service Company of New Mexico, and BANC Phase 2 in 2021; and Tucson Electric Power, Avista, Tacoma Power, and Bonneville Power Administration in 2022.

Xcel Energy, together with Black Hills Colorado Electric, Colorado Springs Utilities, and Platte River Power Authority, announced in December 2019 their intent to join the Western EIM. The group is working with the ISO to finalize the implementation agreement.

Visit the Western EIM website for more information on the market, quarterly benefits reports and other information on its governance, upcoming meetings and initiatives.

###

**California ISO Media Hotline | 888.516.6397**

250 Outcropping Way | Folsom, California 95630 | www.caiso.com

**California-Quebec carbon auction kicks off 2020 with record allowance price**

*By Katelyn Roedner Sutter – Environmental Defense Fund, 02.26.2020*

The results of February's joint California-Quebec auction are in, and 2020 is off to a strong start in the Western Climate Initiative. Fewer allowances were available in this auction than in the past, which could help explain the record high settlement price.

**Highs and lows of the February 2020 auction:**

All 57,090,077 current allowances sold. Notably, this amount is over 10 million fewer allowances than what was offered at the last auction in November 2019. It is also the lowest volume of offered allowances since the very first joint auction in November 2014.

Current allowances cleared at $17.87, which is $1.19 above the price floor of $16.68. This is 87 cents higher than the November 2019 clearing price of $17.00 and 42 cents higher than the previous record-high price of $17.45 from the May, 2019 auction.

8,672,250 future vintage allowances were offered for sale, and all of them sold as well. With over 350,000 fewer future allowances than the November 2019 auction, this was the smallest volume of future allowances ever offered.

The future allowances cleared at $18.00, $1.32 above the floor. These allowances cannot be used for compliance until 2023.

The auction raised approximately $600 million USD for the Greenhouse Gas Reduction Fund, which California will use for programs that further reduce climate and local air pollution and advance environmental equity.

Quebec raised over $240 million CAD (approximately $185 million USD) to support climate action in the province.

**Decreased supply:**

The number of available allowances in this auction was about 15% less than in the previous auction.

One reason for this is the annual decline in the emissions cap. The key feature of a cap-and-trade program is the cap, or limit, on emissions. This binding limit decreases annually, so each year there are fewer allowances in the program. Between 2019 and 2020 the emissions cap decreased almost 3.5%. After 2020, that decline becomes even steeper to ensure that California reduces emissions fast enough to meet the 2030 greenhouse gas reduction goal.

The other main reason for the decrease in available allowances is that more allowances were directly allocated to regulated entities to guard against leakage. The state has policies in place, such as the direct allocation of allowances, to help prevent the shifting of production – and therefore emissions and jobs—out of state. Within a certain industry, specific producers receive different levels of direct allocation based on their output and efficiency. A producers' amount of direct allocation is calculated such that it is not penalized for making more goods, and a producer who can make more goods with fewer emissions is rewarded.

California has directly allocated a certain amount of allowances to industry since the cap-and-trade program began. But with the extension of the cap-and-trade program under AB 398 in 2017, the Legislature directed the California Air Resources Board to increase this direct allowance allocation to industry. That change took effect starting in 2020, so CARB now has fewer allowances available to offer at each auction.

Together, the decline in the emissions cap and the increase in directly allocated allowances contributed to a lower supply of allowances at February's auction, and these features could have been factors in the higher allowance price.

**Higher prices:**

Numerous factors affect prices, including that a more limited supply of allowances can increase the price for those allowances. Companies must have sufficient allowances to meet their compliance obligation. Some of those allowances may have been directly allocated from CARB to prevent leakage, some may be allowances they have saved or "banked," and if they can't reduce their emissions at a lower cost through strategies like equipment upgrades or technological investment, they still may need to purchase allowances at auction.

At the same time, the floor or minimum price of allowances also increased as it does annually; the 2020 floor price is 5% higher plus inflation than the 2019 floor price. This happens each year to ensure that even if demand for allowances drops off, as it did in 2016, there is still a minimum price on those allowances.

**Climate budget:**

Today's auction results delivered additional revenue to the Greenhouse Gas Reduction Fund. This is especially timely as the legislature considers the governor's proposed climate budget, which includes GGRF expenditures, a potential climate resilience bond, and a new Climate Catalyst Fund. Throughout the budget negotiations, EDF will continue to emphasize three priorities:

Innovative local air quality programs like the Community Air Protection Program created by AB 617;

Cleaning up the transportation sector, especially medium- and heavy-duty trucks;

Investing in climate resilience, and the states' natural and working lands as an essential part of climate and resilience strategy.

Revenue and investments are critical to helping meet the climate challenge, and California's cap-and-trade program provides the state with an important funding stream. But the central feature of the program is the declining limit on greenhouse gas emissions; the cap ensures pollution levels decline on pace to meet our climate target.

# 2019 Integrated resource plan

VOLUME II – APPENDICES A-L
OCTOBER 18, 2019


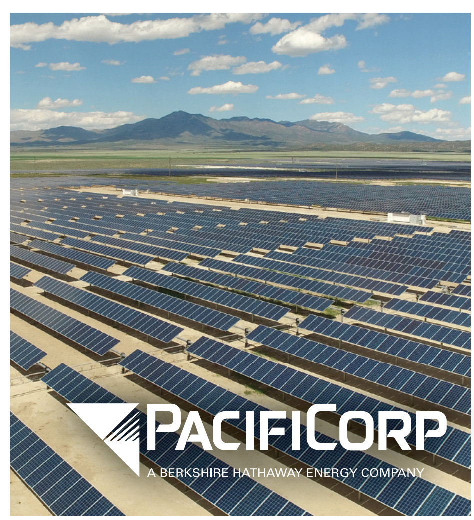

**Table F.7 - Results with PacifiCorp Portfolio Diversity**

| Scenario | Stand-alone Regulation Forecast (aMW) | Diversity Benefit (aMW) | Portfolio Regulation Forecast (aMW) |
|---|---|---|---|
| Non-VER | 110 | (40) | 70 |
| Load | 305 | (110) | 195 |
| VER - Wind | 434 | (157) | 277 |
| VER - Solar | 145 | (53) | 93 |
| **Total** | **994** | **(360)** | **635** |

## EIM Diversity Benefit

In addition to the direct benefits from EIM's increased system visibility and improved intra-hour operational performance described above, the participation of other entities in the broader EIM footprint provides the opportunity to further reduce the amount of regulation reserve PacifiCorp must hold.

By pooling variability in load, wind, and solar output, EIM entities reduce the quantity of reserve required to meet flexibility needs. The EIM also facilitates procurement of flexible ramping capacity in the fifteen-minute market to address variability that may occur in the five-minute market. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA requirements. This difference is known as the "diversity benefit" in the EIM. This diversity benefit reflects offsetting variability and lower combined uncertainty. This flexibility reserve (uncertainty requirement) is in addition to the spinning and supplemental reserve carried against generation or transmission system contingencies under the NERC standards.

The CAISO calculates the EIM diversity benefit by first calculating an uncertainty requirement for each individual EIM BAA and then by comparing the sum of those requirements to the uncertainty requirement for the entire EIM area. The latter amount is expected to be less than the sum of the uncertainty requirements from the individual BAAs due to the portfolio diversification effect of forecasting a larger pool of load and resources using intra-hour scheduling and increased system visibility in the hypothetical, single-BAA EIM. Each EIM BAA is then credited with a share of the diversity benefit calculated by CAISO based on its share of the stand-alone requirement relative to the total stand-alone requirement.

The EIM does not relieve participants of their reliability responsibilities. EIM entities are required to have sufficient resources to serve their load on a standalone basis each hour before participating in the EIM. Thus, each EIM participant remains responsible for all reliability obligations. Despite these limitations, EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority ACE Limit violation. While substantial EIM imports do occur in some hours, it is only appropriate to rely on PacifiCorp's diversity benefit associated with EIM participation, as these are derived from the structure of the EIM rather than resources contributed by other participants.

Table F.8 below provides a numeric example of uncertainty requirements and application of the calculated diversity benefit.

**Table F.8 - EIM Diversity Benefit Application Example**

| Hour | CAISO req't. before benefit (MW) | NEVP req't. before benefit (MW) | PACE req't. before benefit (MW) | PACW req't. before benefit (MW) | Total req't. before benefit (MW) | Total req't. after benefit (MW) | Total diversity benefit (MW) | Diversity benefit ratio (MW) | PACE benefit (MW) | PACE req't. after benefit (MW) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 550 | 110 | 165 | 100 | 925 | 583 | 342 | 37.0% | 61 | 104 |
| 2 | 600 | 110 | 165 | 100 | 975 | 636 | 339 | 34.8% | 57 | 108 |
| 3 | 650 | 110 | 165 | 110 | 1,035 | 689 | 346 | 33.4% | 55 | 110 |
| 4 | 667 | 120 | 180 | 113 | 1,080 | 742 | 338 | 31.3% | 56 | 124 |

While the diversity benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit described above. In the 2019 FRS, PacifiCorp has credited the regulation reserve forecast with a historical distribution of calculated EIM diversity benefits. While this FRS considers regulation reserve requirements in 2017, the CAISO identified an error in their calculation of uncertainty requirements in early 2018. CAISO's published uncertainty requirements and associated diversity benefits are now only valid for March 2018 forward. To capture these additional benefits for this analysis, PacifiCorp has applied the historical distribution of EIM diversity benefits from March 2018 through the beginning of this study in July 2018. Relatively small incremental EIM diversity benefits are expected going forward as additional entities participate in EIM; however, operational data on new participants was not available at the time the study was prepared.

The inclusion of EIM diversity benefits in the 2019 FRS reduces the probability of reserve shortfalls and, in doing so, reduces the overall regulation reserve requirement. This allows PacifiCorp's forecasted requirements to be reduced. As shown in Table F.9 below, the resulting regulation reserve requirement is 531 MW, a 47 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. The average regulation reserve requirement is reduced by 104 MW relative to the PacifiCorp portfolio reserve requirement without the EIM diversity benefit. The portfolio regulation forecast is expected to achieve an LOLP of 0.5 hours per year, based on a quantile regression at a 99.35 percent exceedance level.

**Table F.9 - 2017 Results with Portfolio Diversity and EIM Diversity Benefits**

| Scenario | Stand-alone Regulation Forecast (aMW) | Stand-alone Rate (%) | Portfolio Regulation Forecast w/EIM (aMW) | Portfolio Rate (%) | 2017 Capacity (MW) | Rate Determinant |
|---|---|---|---|---|---|---|
| Non-VER | 110 | 5.7% | 59 | 3.1% | 1,912 | 12 CP |
| Load | 305 | 3.0% | 163 | 1.6% | 10,044 | 12 CP |
| VER - Wind | 434 | 15.8% | 232 | 8.4% | 2,750 | Nameplate |
| VER - Solar | 145 | 14.8% | 78 | 7.9% | 983 | Nameplate |
| **Total** | **994** | | **531** | | | |

## Fast-Ramping Reserve Requirements

As previously discussed, Requirement 1 of BAL-001-2 specifies that PacifiCorp's CPS1 score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection

CASE: UE 375
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 203

## Exhibits in Support
## Of Opening Testimony

**May 15, 2020**

**STAFF EXHIBIT 203**

**IS CONFIDENTIAL AND SUBJECT TO**

**PROTECTIVE ORDER NO. 16-128**

CASE: UE 375
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 204

## Exhibits in Support
## Of Opening Testimony

**May 15, 2020**

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 10

**OPUC Data Request 10**

If PacifiCorp has carried out analysis to quantify all the financial impacts associated with economic cycling on non-fuel plant operation costs, or included such costs in the TAM filing, 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 10**

The Company has not performed the requested analysis and such costs are not included in the transition adjustment mechanism filing.

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.

**OPUC Data Request 12**

With regard to economic cycling decisions:

(a) Please list the issues which are considered when forecasting the economic cycling of units for the TAM.

(b) If the issues listed in response to section "a" have changed since the Company's most recent TAM filing, please provide a copy of the list of issues previously considered, and explain the reason for the change.

(c) Please list the issues that the Company considers when deciding to economically cycle units in actual operations.

(d) If the issues considered differ from those listed in response to section "a", please explain the reason for the difference.

**Response to OPUC Data Request 12**

The Company is assuming that this request relates to the economic cycling of PacifiCorp's owned coal generation units. Based on the foregoing clarification, the company responds as follows:

(a) The Company proposes modeling economic shutdowns for coal plants that are majority-owned by the Company, that are not participating in the energy imbalance market (EIM), and that are not under operational constraints that would preclude an economic shutdown. 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.

(b) The list of issues has not changed since the company's most recent transition adjustment mechanism, Docket UE 356.

(c) PacifiCorp considers economics and reliability in its determination of displacement of resources. Transmission congestion, voltage support, and other operational issues such as maintaining adequate system inertia all play a critical part in determining if a resource can be displaced. The decision to bring a coal plant off-line for economics is looked at on a case-by-case basis.

(d) For economic modeling purposes, Generation and Regulation Initiative Decision Tool is allowed to economically cycle certain coal plants within reasonable constraints. When determining whether to cycle a coal or gas plant in actual operations, PacifiCorp takes into consideration operational needs of the system, such as voltage support and an ability to meet all unknown contingency and operational events.

UE 375/PacifiCorp
April 2, 2020
OPUC Data Request 13

**OPUC Data Request 13**

Please provide the Company’s calculation of DA/RT adders, indicating what time period was used to calculate the adders, and why that time period was selected.

**Response to OPUC Data Request 13**

Please refer to the confidential work papers supporting the direct testimony of David G. Webb and provided with the net power costs 5-day work papers, specifically file “ORTAM21w_DA-RT Price Adder (1912) CONF.xlsx.”

The Company’s day-ahead / real-time (DA/RT) calculations in this proceeding are based on 48 months of data (July 2015 through June 2019). The DA/RT adders are updated on a semi-annual basis using the most recent 48 months of available data. The most recent update available at the time of filing was July 2015 through June 2019.

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OPUC Data Request 16

**OPUC Data Request 16**

Regarding the calculation of EIM benefits:

(a) Please provide a narrative explanation of how the Company calculates EIM benefits.

(b) If the Company's methodology for calculating EIM benefits differs from the methodology used by CAISO, please provide a detailed explanation of that difference.

(c) Please provide a copy of CAISO's calculation of the Company's EIM benefits for calendar year 2019. This data should be provided in electronic spreadsheet format, with all formulas and cell references intact.

(d) If the Company's differs from the methodology used by CAISO, please provide the Company's calculation of its EIM benefits for calendar year 2019 using its currently proposed methodology in the 2021 TAM. This data should be provided in electronic spreadsheet format, with all formulas and cell references intact.

**Response to OPUC Data Request 16**

(a) Using energy imbalance market (EIM) prices and EIM transfer volumes, a transfer value is calculated as the product of prices and volumes for four different scenarios: PacifiCorp East (PACE) Exports, PacifiCorp West (PACW) Exports, PACE Imports and PACW Imports. This transfer value is a revenue for the two export scenarios and a cost for the two import scenarios.

For the two export scenarios, the cost to provide the EIM exports is the cost to increase the energy output of PacifiCorp's resources to support the EIM exports which are incremental to the energy required to serve native load. For the two import scenarios, the cost avoided by importing energy from the EIM is the cost savings associated with decreasing the energy output of PacifiCorp's resources to support the EIM imports which are decremental to the energy required to serve native load.

The EIM benefit for the export scenarios is the transfer value less the cost. The EIM benefit for the import scenarios is the avoided cost less the transfer value.

Please refer to Confidential Attachment OPUC 16 for the details of the calculations.

(b) The Company's methodology for calculating EIM benefits uses balancing authority area (BAA) level EIM transfer volumes along with BAA level EIM prices to determine transfer values and a BAA level resource stack to determine the associated costs or avoided costs. The California Independent System Operator's (CAISO) methodology uses resource level imbalance energy along with resource level EIM prices to determine transfer values along with resource level bids to determine associated costs, avoided costs and intra-regional benefits.[1]

(c) PacifiCorp does not receive copies of the work papers used by the CAISO to calculate the company's EIM benefits.

(d) Please refer to Confidential Attachment OPUC 16.

Confidential Attachment OPUC 16 is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

[1] As the Public Utility Commission of Oregon (OPUC) determined in the 2016 transition adjustment mechanism (TAM), the Generation and Regulation Initiative Decision Tool (GRID) net power costs (NPC) forecast already reflects the optimized (i.e., lowest cost) dispatch of PacifiCorp's generating resources within its two balancing authority areas (BAA), therefore there are no additional benefits from the energy imbalance market (EIM) optimized dispatch (i.e., intra-regional and within-hour dispatch benefits). Docket UE-296, Order 15-394.

**OPUC Data Request 18**

Please provide a step-by-step explanation of how the Company's EIM benefits forecast was derived, with reference to the work papers provided in the Company's filing.

**Response to OPUC Data Request 18**

**Energy imbalance market (EIM) transfer benefit forecast:**
Forecasts were created for four different scenarios / models: PacifiCorp East (PACE) exports, PacifiCorp West (PACW) exports, PACE imports and PACW imports.

Please refer to the confidential work papers supporting the direct testimony of Ramon J. Mitchell, specifically folder "Market Fundamentals Forecast CONF.zip" and the five Microsoft Excel files, and one 'R' script.

Note: The PACE export model uses the "PACE_Export_Mona.xlsx" historical work paper. The PACE import model uses the "PACE_Import_Mona.xlsx" historical work paper. The PACW export model uses the "PACW_Export_MIDC.xlsx" historical work paper. The PACW import model uses the "PACW_Import_MIDC.xlsx" historical work paper. All models use file "OFPC.xlsx" as the future period work paper.

For the PACE export model, firstly, all instances of negative margins are removed from the data (if any). Then, a linear regression was performed using the following equation as expressed in line 26 of the R script

Margin^(1/2) ~ I(Power_Price^2) + I(Gas_Price^2) + Bilateral_EIM + Enbridge

The variable names are identical to the column names in the referenced work papers, and the "I" outside of the brackets is simply a method to indicate that the statement within the brackets is a formula.

To correct for data stationarity issues, the Cochrane-Orcutt procedure[1] is run and the coefficients of the linear regression are updated - line 30 and line 33 of the R script.

The linear regression model is then used to forecast EIM benefits by applying the model to the future periods in file "OFPC.xlsx." The mapping of column names from the PACE export work paper to the OFPC work paper is as follows:

[1] PAC/200, Mitchell/17, lines 16-20 provide an explanation of the Cochrane-Orcutt procedure.

Power_Price = Mona_Flat, Gas_Price = Opal, Bilateral_EIM = 0, Enbridge = 0

The forecast produced after applying the model to the future periods is a monthly forecast expressed as an average daily value. Consequently each monthly forecast is multiplied by the number of days in the month. The 12 resulting values are summed to produce the 2021 EIM transfer benefit forecast.

The procedure to forecast the other three models are identical with the following exceptions:

PACW export equation: Margin^(1/2) ~ I(Power_Price^2) + I(Gas_Price^2) + Enbridge.

Mapping from PACW export work paper to OFPC work paper: Power_Price = MIDC_Flat, Gas_Price = Stanfield, Enbridge = 0

PACE import equation: log(Margin) ~ log(Power_Price) + TTC + Spring_Increasing.

Mapping from PACE import work paper to OFPC work paper: Power_Price = Mona_Flat, Spring_Increasing = Spring_Increasing, TTC = PACE_Import_TTC

PACW import equation: log(Margin) ~ log(Power_Price) + TTC + Spring_Increasing

Mapping from PACE import work paper to OFPC work paper: Power_Price = MIDC_Flat, TTC = PACW_Import_TTC, Spring_Increasing = Spring_Increasing

**EIM greenhouse gas (GHG) benefit forecast:**
The 2021 forecast is a naïve[2] forecast.

Please refer to the confidential work papers supporting the direct testimony of Ramon J. Mitchell, specifically file “Mitchell - Workpapers CONF.xlsx,” tab “Analysis.” In that tab in column G, from cells G49 to G60, are the most recent EIM GHG actual benefits as of November 2019. The sum of these values is the 2021 forecast.

[2] PAC/200, Mitchell/18, lines 15-17 provides an explanation of a naïve forecast.

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OPUC Data Request 19

**OPUC Data Request 19**

Please provide a narrative explanation of how the Company accounts for the reserve benefits of EIM participation.

**Response to OPUC Data Request 19**

The regulating reserve requirement modeled in the Generation and Regulation Initiative Decision Tool uses the results from the Company's 2019 Integrated Resource Plan's (IRP) flexible reserve study. In this study, the Company's share of the reserve benefit based on the diversified footprint of the energy imbalance market is explicitly accounted for, and the regulating reserve requirement is reduced by approximately 104 megawatts.

Please refer to PacifiCorp's 2019 IRP, specifically Appendix F (Flexible Reserve Study), page 101 and 102. The 2019 IRP is publicly available and can be accessed by utilizing the following website link:

https://www.pacificorp.com/energy/integrated-resource-plan.html

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OPUC Data Request 22

**OPUC Data Request 22**

PAC/200, Mitchell/10, lines 7 - 8 state "the anticipated EIM entrants for 2020 and 2021 are not expected to increase PacifiCorp's transfer capability with the CAISO".

(a) Please provide data illustrating this statement in electronic spreadsheet format, with all formulas and cell references intact.

(b) Does the Company consider its connectivity to CAISO to be more valuable (in terms of EIM benefits) than its connectivity to the rest of the EIM participants? If yes, please explain why this is the case, providing data to support this in electronic spreadsheet format, with all formulas and cell references intact.

**Response to OPUC Data Request 22**

(a) Please refer to Attachment OPUC 22-1 in which it is observed that none of the 2020 or 2021 entrants are located between PacifiCorp and the California Independent System Operator (CAISO).

(b) The Company considers its connectivity to the CAISO to be more valuable (in terms of energy imbalance market (EIM) benefits) for imports. The combined solar, wind and hydroelectric capacity of the CAISO is substantial and this leads to low EIM prices during the spring.

Please refer to Attachment OPUC 22-2. In this attachment, Figure 1.3 illustrates the intra-day average output by resource type in Q2 2019, Figure 1.6 illustrates the average monthly EIM prices from January 2018 through June 2019, and Figure 1.7 illustrates the intra-day average EIM prices in Q2 2019. It is these low prices during the middle of the day in spring, driven by CAISO solar, wind and hydroelectric generation, which drive the majority of PacifiCorp's EIM import benefits in both the PacifiCorp East and the PacifiCorp West balancing authority areas.

Please refer to the following link which provides data on CAISO wind and solar oversupply by month:

http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

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OPUC Data Request 24

**OPUC Data Request 24**

PAC/200, Mitchell/12, lines 13 - 15 state "the EIM footprint currently encompasses approximately 60 percent of Western Electricity Coordinating Council load and the entities joining the market in 2020 and 2021 will not increase this percentage substantially".

(a) Please provide a copy of the document referenced in footnote 3 in electronic format.

(b) Please indicate what percentage of the Western Electricity Coordinating Council load will be served by the EIM following the entry of the new entities in 2020 and 2021.

(c) Does the Company's EIM benefits forecasting model account for the increase in transmission capacity caused by the entry of new participants in 2020 and 2021?

(d) If yes to section "c" above, please provide an explanation of the Company's response, including references to where this increase can be identified in the workbooks provided by the Company.

**Response to OPUC Data Request 24**

(a) Please refer to Attachment OPUC 24, specifically page 8. Attachment OPUC 24 is a document that PacifiCorp has access to through a subscription, please contact PacifiCorp before any disclosure or dissemination of this document.

(b) Approximately 70 percent as noted in Attachment OPUC 24, specifically page 8.

(c) No. The Company's energy imbalance market (EIM) benefits forecasting models account for increases in transmission capacity between PacifiCorp and the California Independent System Operator (CAISO). For example, the entry of Nevada Power into the EIM increased the transmission capacity between PacifiCorp and the CAISO. Please refer to the company's response to OPUC Data Request 22 which provides a more detailed explanation.

(d) Please refer to the Company's response to subpart (c) above.

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OPUC Data Request 27

**OPUC Data Request 27**

Staff notes that when the Company facilitates a wheel through in EIM, it receives no direct financial benefit, as only the sink and source BAA directly benefit from the wheel through. CAISO's fourth quarter 2019 EIM benefits report[1] indicates that significant volumes of transfers are conducted using the Company's system, in particular the PACW system.

(a) If the Company has engaged with CAISO regarding this matter, please provide a summary of the content of those communications to date.

(b) If the Company has conducted any analysis or tracking of EIM wheel through in its territory, please provide a copy of this analysis and a narrative explanation of the results.

(c) If the Company has conducted any analysis quantifying the value lost through EIM wheel through in its territory, please provide a copy of this analysis and a narrative explanation of the results.

(d) If the Company has an expectation of how wheel through transfers will be treated in the potential extended day-ahead market[2], or has taken a position on this issue, please provide a narrative explanation of this.

**Response to OPUC Data Request 27**

(a) The California Independent System Operator (CAISO) has engaged with the energy imbalance market (EIM) entities and is "committed to monitoring the wheel-through volumes to assess whether, after the addition of new EIM entities, there is a potential future need to pursue a market solution to address the equitable sharing of wheeling benefits." This quotation is provided at the bottom of page 9 in the document located at the following CAISO website link:

http://www.caiso.com/Documents/IssuePaper-ExtendedDayAheadMarket.pdf

(b) The CAISO publishes, on a quarterly basis, balancing authority area (BAA) specific wheel through volumes for each month. The data, calculation methodology and narrative descriptions are publicly available and provided in the quarterly "PDFs" published at the following CAISO website link:

[1] EIM Quarter 4 2019 EIM benefits report, page 11, table 3. Accessible at: www.westerneim.com/Documents/ISO-EIMBenefitsReportQ4-2019.pdf.
[2] As referenced in UE 374, PAC/500, Wilding/18.

https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

(c) PacifiCorp has not conducted an analysis of the value lost through EIM wheel-through transfers in its territory.

(d) The EIM entities have jointly presented on transmission elements of an extended day-ahead market design. A narrative description of the position of the EIM entities (which include PacifiCorp) on this issue, inclusive of wheel through transfers, is provided in the following presentation that is publicly available and can be accessed by utilizing the following CAISO website link:

http://www.caiso.com/InitiativeDocuments/Presentation-ExtendedDay-AheadMarket-TransmissionProvision-EIMEntities.pdf

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OPUC Data Request 28

**OPUC Data Request 28**

PAC/200, Mitchell/18, lines 9 – 10 state "the EIM GHG benefits are the GHG revenues less the Company's compliance costs". Please indicate how the Company defines "the Company's compliance costs", including the Company's calculation of this value and clear references to the input data used.

**Response to OPUC Data Request 28**

The Company's compliance costs are the costs to procure California Carbon Allowances (CCA) for the energy attributed as serving California Independent System Operator (CAISO) load in the energy imbalance market (EIM).

For EIM participating resources, energy in megawatt-hours (MWh) – greenhouse gas (GHG) quantity - is attributed as serving CAISO load in the EIM on a resource specific basis. Each resource has an emissions cost in dollars per megawatt-hour ($/MWh). This cost is the product of the resources emission factor in metric-tons per megawatt-hour (MT/MWh) and the cost of the CCAs in dollars per metric-ton ($/MT). The product of the GHG quantity (MWh) and the emissions cost ($/MWh) is the resources' compliance cost. The sum of all resources' compliance costs is the company's compliance cost for a given time period.

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April 2, 2020
OPUC Data Request 34

**OPUC Data Request 34**

Regarding CAISO's November 2018 GHG accounting changes[1]:

(a) Please provide a narrative explanation of how the changes at CAISO affected the GHG benefits received by the Company.

(b) Please include copies of any analysis carried out by the Company which supports the answer provided to section "a". Please provide this data in electronic spreadsheet format, with all formulas and cell references intact.

(c) Please provide a narrative explanation of how the Company's reflected CAISO's November 2018 change in its forecast of GHG benefits.

**Response to OPUC Data Request 34**

(a) The November 2018 policy change led to an increase in energy imbalance market (EIM) greenhouse gas (GHG) benefits.

(b) Please refer to the Company's response to OPUC Data Request 33, specifically Confidential Attachment OPUC 33. Tab "GHG Data" displays a chart showing the aforementioned increase. Specifically, the light blue line labeled "Actuals (GHG Marginal Revenue)."

(c) As discussed in the direct testimony of Ramon J. Mitchell, specifically Exhibit PAC/200, Mitchell/19, lines 1-3, and as also discussed in the Company's response to OPUC Data Request 33, PacifiCorp reflected the California Independent System Operator's (CAISO) November 2018 policy change by using only actual EIM GHG benefit data post November 1, 2018 to develop the forecast of EIM GHG benefits.

[1] As referenced in UE 356, PAC/500, Brown /4.

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OPUC Data Request 41

**OPUC Data Request 41**

Please provide the Company's definition of "system balancing", "short term", and "long term" sales and purchases, including detail of the timeline of each, and markets regularly transacted in.

**Response to OPUC Data Request 41**

"Short-term" is used by the Company to refer to transactions with a term-length less than one year.

"Long-term" transactions are defined as transactions with a length greater than one year.

In the Generation and Regulation Initiative Decision Tool, "System Balancing" refers to model-driven market transactions which are used in the model to economically balance load and resources in the forecast period on an hourly basis. In the company's net power costs report, these are distinguished from short-term and long-term transactions, which are actual transactions already executed by the company with delivery during the forecast period and which are reflected based on the specific terms of the transaction.

The Company regularly transacts at the following market locations: California-Oregon Border, Four Corners, Mead, Mid-Columbia, Mona, and Palo Verde.

**OPUC Data Request 61**

**Wholesale Purchases -** With regard to the data provided in the Company's confidential response to DR 39:

(a) Staff notes that both the dollar value and MWh volume of "Total Wholesale Sales" tends to be higher in the Company's initial filing than in actual results. Please provide a narrative explanation of this pattern, as understood by the Company. This pattern is highlighted in the document "UE 375 DR 61 CONF ME - Attachment A".

(b) Please provide a narrative explanation of any efforts taken by the Company to adjust its forecast to more accurately reflect expected "Total Wholesale Sales" in earlier versions of its Power Cost filing.

(c) Staff notes that both the dollar value and MWh volume of "Short Term Sales" tends to be lower in the Company's initial filing than in actual results. Please provide a narrative explanation of this pattern, as understood by the Company. This pattern is highlighted in the document "UE 375 DR 61 CONF ME - Attachment A".

(d) Please provide a narrative explanation of any efforts taken by the Company to adjust its forecast to more accurately reflect expected "Short Term Sales" in earlier versions of its Power Cost filing.

(e) Staff notes that both the dollar value and MWh volume of "Short Term Purchases" tends to be lower in the Company's initial filing than in actual results. Please provide a narrative explanation of this pattern, as understood by the Company. This pattern is highlighted in the document "UE 375 DR 61 CONF ME - Attachment A".

(f) Please provide a narrative explanation of any efforts taken by the Company to adjust its forecast to more accurately reflect expected "Short Term Purchases" in earlier versions of its Power Cost filing.

**Response to OPUC Data Request 61**

(a) The pattern observed by Public Utility Commission of Oregon (OPUC) staff in OPUC provided file "PAC UE 375 OPUC DR 61 CONF ME - Attachment A" indicates that the company over forecasted wholesale power sales in years 2015 through 2019. This is due to the differences between forecasted assumptions and actual system, market and operational conditions.

(b) In the past, the Company addressed this issue by specifying the limits to market depth for four major market hubs – California Oregon Broader (COB), Four Corners (4C), Mead and Mona - during all hours in the Generation and Regulation Initiative Decision Tool (GRID). GRID is a perfect foresight model with static prices. Without market caps, GRID will continue to transact in the markets until other system constraints are reached. The Company believes that a market may be liquid, but this liquidity may be less during actual operations. Due to load requirements and transmission constraints in the region and static assumptions about market prices in GRID, among other things, in actual operation with dynamic conditions, the Company may not have the flexibility to sell all of its economic generation to the markets.

The market depths for wholesale sales in GRID were originally determined by the average of historical short-term firm (STF) transactions during the same 48-month period on which availability of the thermal generation is based. The depths are then reduced by the quantity of STF transactions that the Company has included in the normalized net power costs (NPC) study for the test period in all sales markets. The method was approved by the OPUC in docket UE 227. However, in docket UE 245, Order 12-409, the OPUC ordered the Company to change its method for calculating the market caps and to instead use the highest of the four most recently available relevant averages for each trading hub, each month, and differentiated by on-peak and off-peak hours instead of the average of the 48-month period. The Company has been modeling market caps in GRID consistent with OPUC Order 12-409 in its annual transition adjustment mechanism (TAM) filings since.

(c) STF 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. The STF sales dollars and megawatt-hours in the Company’s initial filing is at a lower level than in actual results. This is because the STF sales are actual STF transactions, or hedges the Company has entered into for the test period. The Company hedges on a rolling 36-month horizon, but the majority of the trading activity is for the next 12 months. Therefore, the final TAM filed in November will have larger volumes of STF sales than the initial TAM filing. The volumes of STF sales for the test period will increase with each subsequent TAM update until the final TAM filing.

(d) The Company uses the most recent STF transaction information in each of its TAM filings throughout the year (initial, update, indicative and final).

(e) Please refer to the Company’s response to subpart (c) above.

(f) Please refer to the Company’s response to subpart (d) above.

UE 375/PacifiCorp
May 4, 2020
OPUC Data Request 64

**OPUC Data Request 64**

**EIM –** Please provide a breakdown of the CAISO's calculation of PacifiCorp's EIM benefits into the following categories, for each year since 2014:

(a) GHG benefits.

(b) Flex reserve benefits.

(c) Energy transfer benefits.

**Response to OPUC Data Request 64**

The California Independent System Operator's (CAISO) calculation of PacifiCorp's energy imbalance market (EIM) benefits is performed and maintained by the CAISO for the CAISO. PacifiCorp has no archive of the CAISO calculated benefits or the breakdown of these benefits into its components. The total EIM benefits calculated by the CAISO are publicly available in quarterly documents and can be accessed by utilizing the following website link:

https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

UE 375/PacifiCorp
May 4, 2020
OPUC Data Request 68

**OPUC Data Request 68**

**EIM –** The Company's response to DR 34 states that "the November 2018 policy change led to an increase in energy imbalance market greenhouse gas (GHG) benefits". Please provide an explanation of how the CAISO policy change increased the Company's GHG benefits.

**Response to OPUC Data Request 68**

Before the California Independent System Operator (CAISO) policy change, the amount of energy that was eligible to be allocated as having served California Independent System Operator (CAISO) load (greenhouse gas (GHG) quantity) was a resource's "Pmax." To simplify, after the policy change this quantity was limited to a resource's "Pmax" less the base schedule.[1] The policy change therefore limited the amount of GHG quantity that each resource in the energy imbalance market (EIM) could provide and this led to an increase in the marginal cost of GHG (GHG price) in the EIM.

As the GHG price increases, the spread between the GHG revenue and the GHG cost increases for all resources that are infra-marginal. This spread is a resource's GHG benefit. The marginal GHG resource (the resource that sets the GHG price) after the policy change has had a GHG cost that has been, on average, sufficiently higher than the pre-policy marginal GHG resource such that the increase in benefits on infra-marginal resources' GHG quantities has outweighed the decrease in benefits from the reduction in the resources' GHG quantities for PacifiCorp resources.

Consider a 100 megawatt (MW) natural gas resource with an 80 megawatt-hour (MWh) base schedule. Prior to the policy change, 100 MWh was eligible to be allocated as having served CAISO load, and with the policy change 20 MWh is now eligible to be allocated as having served CAISO load.

Consider a hypothetical EIM footprint with three non-CAISO resources (all PacifiCorp owned) and a CAISO EIM import of 110 MWh.

1. Resource A is a 100 MW hydro resource with a 40 MWh base schedule and a GHG bid of $0/MWh.

2. Resource B is a 120 MW natural gas resource with a 90 MWh base schedule and a GHG bid of $7/MWh.

[1]Technically, this quantity was limited to a resource's upper economic limit less the base schedule

3. Resource C is a 150 MW coal resource with a 120 MWh base schedule and a GHG bid of $20/MWh.

Prior to the policy change, the CAISO would allocate 100 MWh from Resource A and 10 MWh from Resource B as having served CAISO EIM imports of 110 MWh based on these resources' "Pmax" and their GHG bids. The marginal cost of GHG in the EIM footprint would be $7/MWh (the cost of the last resource allocated as having served CASIO load). Resource A would earn a benefit of $700 (a revenue of 100 MWh * $7/MWh less a cost of 100 MWh * $0/MWh), and Resource B would earn a benefit of $0 (a revenue of 10 MWh * $7/MWh less a cost of 10 MWh * $7/MWh). Total GHG benefits would be $700.

After the policy change, the CAISO would allocate 60 MWh from Resource A, 30 MWh from Resource B and 20 MWh from Resource C as having served CAISO EIM imports of 110 MWh based on these resources' capacities above base schedules and their GHG bids. The marginal cost of GHG in the EIM footprint would be $20/MWh (the cost of the last resource allocated as having served CAISO load). Resource A would earn a benefit of $1,200 (a revenue of 60 MWh * $20/MWh less a cost of 60 MWh * $0/MWh), Resource B would earn a benefit of $390 (a revenue of 30 MWh * $20/MWh less a cost of 30 MWh * $7/MWh) and Resource C would earn a benefit of $0 (a revenue of 20 MWh * $20/MWh less a cost of 20 MWh * $20/MWh). Total GHG benefits would be $1,590.

UE 375/PacifiCorp
May 6, 2020
OPUC Data Request 86

**OPUC Data Request 86**

**CONFIDENTIAL REQUEST - EIM**
Regarding **[CONFIDENTIAL BEGINS** [redacted] **[CONFIDENTIAL ENDS]**, as shown in the Company's response to DR 17, please provide a narrative explanation of how **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** occurred. Include data to support this explanation in electronic workbook format, with all cells and formulas intact.

**Response to OPUC Data Request 86**

Negative energy imbalance market (EIM) benefits may occur during scarcity or oversupply pricing events. For example, if the EIM is unable to procure sufficient energy in sufficient time to balance against load and interchange requirements for a given balancing authority area (BAA), then the marginal cost of energy in the BAA may be set at an administrative penalty price of approximately $1,000 per megawatt-hour ($/MWh), signaling the BAA's energy scarcity to the EIM. At this price, all imports will be paid the penalty price of $1,000/MWh.

The occurrence of negative margins in the monthly totals for PacifiCorp West in August 2015 and October 2017 were driven by scarcity pricing events.

Please refer to Confidential Attachment OPUC 86 for an example.

Confidential Attachment OPUC 86 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 6, 2020
OPUC Data Request 93

**OPUC Data Request 93**

**EIM**
Please supplement the Company's response to Staff DR 31 with the following information in electronic workbook format with all cells and formulas intact:

(a) The Company's California Carbon Allowance compliance cost in dollars for day-ahead and hour-ahead sales to CAISO.

(b) The Company's calculation of the values provided in response to section "a".

(c) The GHG California Carbon Allowance prices used to calculate the values provided in response to section "a".

(d) The Company's calculation of the values provided in response to section "c", including an explanation of how these values relate to the Company's GHG California Carbon Allowances purchases shown in the Company's response to DR 32.

(e) The Company's California Carbon Allowance compliance cost in dollars for EIM exports.

(f) The Company's calculation of the values provided in response to section "e".

(g) The GHG California Carbon Allowance prices used to calculate the values provided in response to section "e".

(h) The Company's calculation of the values provided in response to section "g", including an explanation of how these values relate to the Company's GHG California Carbon Allowances purchases shown in the Company's response to DR 32.

**Response to OPUC Data Request 93**

The Company has not performed the requested analysis. The Company does not make separate greenhouse gas (GHG) California carbon allowance purchases for day-ahead / hour-ahead and energy imbalance market (EIM) compliance. Since these allowances are purchased together, to try and separate them after the fact would merely be a best guess. Once the Company's yearly California carbon allowance total obligation is trued up from the estimate, deficiencies may be purchased months after the year has ended along with allowances for the current year. This true up process makes it even more difficult to separate the purchased GHG California carbon allowance purchases between day-ahead / hour-ahead and EIM after the fact.

**OPUC Data Request 105**

**Economic Cycling**
Staff understands that the Company often extends planned outages of generators, when there is an economic benefit to doing so.

(a) Please indicate whether the GRID model accounts for the opportunities presented by planned outages, when forecasting economic cycling.

(b) If yes to section “a”, please provide a narrative explanation of how the GRID model accounts for the opportunities presented by planned outages, when forecasting economic cycling. Provide data to support the Company’s answer in electronic workbook format, with all cells and formulas intact.

**Response to OPUC Data Request 105**

(a) Yes, the Generation and Regulation Initiative Decision Tool (GRID) does account for the opportunities presented by planned outages when forecasting economic cycling.

(b) Thermal units generation attributes, such as nameplate capacity, normalized outage and maintenance schedules, are used to calculate the available capacity of each unit for each hour. GRID determines the hourly commitment status of thermal units based on planned outage schedules, and a comparison of operating cost versus market price if the unit is capable of cycling up or cycling down in a short period of time. The commitment status of a unit indicates whether it is economical to bring that unit online in that particular hour. The availability of thermal units and their commitment status are used in the dispatch logic to determine how much may be generated each hour by each unit. GRID then uses system optimization algorithm to determine how the available thermal resources should be dispatched economically given load requirements, transmission constraints and market conditions, and whether market purchases or sales should be made to balance the PacifiCorp West balancing authority area. In addition, if market conditions allow, market purchases may be used to displace more expensive thermal generation. At the same time, market sales may be made either from excess resources or market purchases if it is economical to do so under market and transmission constraints.

**Sierra Club Data Request 1.25**

With respect to the GRID model in calculating the 2021 NPC:

(a) Please explain whether coal units' operation in TAM 2021 are subject to a must-run constraint (or any other constraint requiring the coal units to operate independently of their cost for any time period within the year). If so, please identify the units, required output level, and number of hours during which the constraint applies.

(b) Please explain whether and how self-scheduling is modeled in GRID.

(c) Please provide a list of any other constraint that applies on the coal units' operations within GRID.

**Response to Sierra Club Data Request 1.25**

(a) All coal units, except Hunter Unit 1 and Hunter Unit 2, during the period of February 1 and May 31 are subject to a must-run constraint.

(b) There is no self-scheduling modeled in the Generation and Regulation Initiative Decision Tool (GRID).

(c) There are no other constraints that are applied to the coal units' operations in GRID. For the coal units' operational characteristics, please refer to the company's response in Sierra Club Data Request 1.10 subpart (d).

CASE: UE 375
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 205

## Exhibits in Support
## Of Opening Testimony

**May 18, 2020**

**STAFF EXHIBIT 205**

**IS CONFIDENTIAL AND**

**IS FILED IN ELECTRONIC FORMAT**

CASE: UE 375
WITNESS: SABRINNA SOLDAVINI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 300

# Opening Testimony

**May 15, 2020**

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

A. My name is Sabrinna Soldavini. I am a Senior Regulatory Analyst employed in the Energy Finance and Audit Division of the Public Utility Commission of Oregon (OPUC).My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

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

A. My witness qualification statement is found in Exhibit Staff/301.

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

A. The purpose of my testimony is to describe Staff's position on the following issues: Other Revenues, Coal Contracts, Naughton 3 Gas Conversion, Jim Bridger Fuel Plan & Bridger Coal Company Depreciation, and the Company Supply Service Access Charge.

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

A. Yes. I prepared the following exhibit, Exhibit Staff/302, PacifiCorp Responses to Staff Data Requests.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1, OTHER REVENUES

**Q. Please describe what Other Revenues are in the context of this filing?**

A. In Docket No. UE 216, PacifiCorp's 2011 Transition Adjustment Mechanism (TAM), Staff raised the issue of a mismatching between updating costs and revenues if a Company is allowed to include, or update, the costs associated with new resources, contracts and existing facilities for services it provides to third parties and are accounted for as "other revenue" in standalone power cost filings.[1] As such, Order No. 10-363 in Docket No. UE 216, stipulated that in future standalone TAM filings, the Company would include an update to Other Revenues related to net power costs (NPC).

The Company reports the update to Other Revenues as the difference from the baseline levels specified in UE 217. Examples of Other Revenues accounted for through Schedule 205 in prior TAMs include those from storage and exchange agreements with Seattle City Light – Stateline Wind Farm, Non-Company owned Foote Creek projects, revenues from BPA associated with the South Idaho Exchange, steam revenues for Little Mountain Steam Revenues, and royalty offset revenues for the James River contract.

**Q. How does PacifiCorp propose to treat Other Revenues in the 2021 TAM?**

A. As this year's TAM is a not a standalone TAM, and was filed concurrently with the Company's General Rate Case (GRC), Docket No. UE 374, the Company has proposed that Schedule 205 rates be set to zero as the present

[1] *See* UE 216, Staff/100, Brown/14.

adjustments get incorporated into base rates. The Company proposes to leave Schedule 205 in place and continue to update Schedule 205 for incremental changes in Other Revenues in future TAMs.[2]

**Q. Does Staff have any issues with the Company's proposal?**

A. No. Staff takes no issue with the Company's proposal, and supports keeping the Schedule 205 tariff in place for future use. Staff recommends that in future standalone TAM filings, the Company reflect forecast changes in Other Revenues for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in UE 374, in Schedule 205.

[2] PAC/400, Ridenour/3.

## ISSUE 2, COMPLIANCE WITH 2020 TAM - JIM BRIDGER FUEL PLAN & BRIDGER COAL COMPANY

*Bridger Coal Company*

**Q. Please explain Bridger Coal Company's (BCC) relationship to PacifiCorp.**

A. BCC is a joint venture of Idaho Power and PacifiCorp, which is owned by Idaho Energy Resources Co. (IERCO), a wholly owned subsidiary of Idaho Power, and Pacific Minerals, Inc. a wholly owned subsidiary of PacifiCorp. BCC charges PacifiCorp for coal at cost, which includes a component of BCC depreciation expense. The coal that BCC produces supplies PacifiCorp's Jim Bridger plant.

In the 2019 TAM, Staff raised the issue of the Company's recovery of depreciation expense from ratepayers related to plant that has been added since the Company's last general rate case and thus has yet to be reviewed for prudence.[3] In the stipulation approved in Order No. 18-421, the stipulating parties agreed that in subsequent power cost cases, PacifiCorp would provide additional information detailing the justification of the depreciable lives of BCC assets as well as any variations to BCC depreciation levels from the levels established in the Company's previous TAM, for each year since the Company's previous rate case.

[3] UE 339 Staff/200, Kaufman/13 through Kaufman/16.

**Q. How was this issue treated in the 2020 TAM?**

A. In the 2020 TAM, Staff recommended that PacifiCorp, Staff, Idaho Power and interested parties convene a workshop to work through the BCC depreciation issues in a consistent manner. In the stipulation approved in Order No. 19-351, PacifiCorp agreed to hold a workshop to discuss BCC depreciation costs prior to January 1, 2020.

**Q. Does Staff confirm that the BCC depreciation workshop occurred?**

A. Yes, PacifiCorp and Idaho Power held a workshop for interested parties on September 23, 2019. No further action came from the workshop.

**Q. Does Staff have a recommendation for this issue?**

A. As PacifiCorp is currently in the middle of a general rate case, the level of BCC expense allowed into base rates will be determined in Docket No. UE 374. Staff recommends that moving forward, in stand-alone TAM filings the Company continue to provide workpapers outlining the depreciable lives of BCC assets, including descriptions of how and why BCC depreciation expense has varied from the level set in UE 374.

*Jim Bridger*

**Q. How was the Jim Bridger plant treated in the 2020 TAM?**

A. In Order No. 20-023, the Commission required the Company to provide testimony on the fueling arrangements at Jim Bridger in light of earlier end-of-life dates, with explanations of how the Company is planning ahead for flexible fueling arrangements to avoid minimum take penalties.[4]

[4] Docket No. UE 366, Order No. 20-023.

Order No. 20-023 also states that PacifiCorp shall participate in a Commission workshop after the filing of the 2021 TAM.

**Q. Did PacifiCorp comply with the Commission's Order?**

A. The Company has included in its testimony a description of its Jim Bridger fueling plan. The Company states that Jim Bridger is fueled by Bridger Coal Company and Black Butte Coal Company (Black Butte), a third-party coal supplier. PacifiCorp states that the Black Butte agreement is for an annual fixed tonnage volume that is "significantly less than the total consumed tonnage at the Jim Bridger plant."[5] The contracted annual volume is equal to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the total coal consumption at Jim Bridger.[6] PacifiCorp further indicates that because BCC is a subsidiary of PacifiCorp, coal deliveries from BCC can be "flexed down to satisfy the Jim Bridger's plant's requirements, as necessary"[7] making the risk of incurring minimum take penalties unlikely.

**Q. When does the coal supply agreement with Black Butte end?**

A. The current coal supply agreement with Black Butte expires at the end of 2021. PacifiCorp states that when this contract expires it will **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and that it will "continue to review the Jim Bridger plant's fueling requirements and procure the appropriate

[5] PAC/300, Ralston/3.
[6] *Ibid.*
[7] *Ibid.*

tonnage volume of coal, with flexibility and cost in mind, to mitigate the risk of incurring minimum take penalties."[8]

**Q. Does Staff have any issues with the Company's description of its fueling plan for Bridger?**

A. Staff believes it is reasonable to assume that because the contract with Black Butte Coal Company only supplies **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** of the Jim Bridger plant's fueling requirements, and there is flexibility in coal deliveries from BCC, it is unlikely that PacifiCorp will incur minimum take payments. However, it is important to highlight that while the deliveries from BCC may be flexed down as necessary to avoid such payments, any flexing down of volumes delivered from BCC can be offset by corresponding increases in the price of BCC coal, as BCC's operational costs are passed through in the price of coal it delivers to the Jim Bridger plant.

Staff believes this fact underscores the need for PacifiCorp to be vigilant in its long term fueling plan for the Jim Bridger plant to both ensure that any future coal supply agreement is necessary, prudent, and does not lead to BCC reducing its volumes to levels that significantly increase the price PacifiCorp must pay BCC for coal.

**Q. Has PacifiCorp participated in the Commission workshop as required by Order No. 20-023?**

A. While a Commission workshop was scheduled to take place on April 10, 2020 in compliance with Order No. 20-023, it was cancelled by the Commission on

[8] PAC/300, Ralston/4.

April 8, 2020, as the Commission was interested in a level of depth that PacifiCorp was unable to provide given the short notice of the Commission's requested workshop agenda. The Commission stated in its notice of cancellation that it would work with parties to reschedule the workshop.[9] This has been rescheduled for May 12, 2020; as such, Staff finds that PacifiCorp has reasonably complied with the Commission Order.

[9] UE 375, Notice of Cancellation of Commission Workshop, April 8, 2020.

## ISSUE 3, COAL CONTRACTS

**Q. Please describe the change in coal expense between the 2021 and 2020 TAM?**

A. As of its initial 2021 TAM filing, the Company expects total coal fuel expense to be $79.4 million less than the 2020 TAM, decreasing from $692.1 million in the 2020 TAM final update to $612.7 million in the initial 2021 TAM filing.[10] The Company notes that this is due to lower coal generation volume; however, this lower coal generation volume is partially offset by average coal prices that are $0.83/MWh higher than in the 2020 TAM. As the Company's testimony outlines, the increase in average coal prices "is driven by changes in third-party coal supply and rail contracts since last year's TAM."[11]

**Q. Please describe the change in the overall third-party coal supply costs in the 2021 TAM as compared with those in the 2020 TAM.**

A. In the Company's initial 2021 TAM filing it expects a net increase in third-party coal supply costs of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**.[12]

**Q. What are the primary drivers for the change in overall third-party coal supply costs?**

A. Primary drivers include an increase in total delivered costs at Naughton, which increased by **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** per ton from **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** per ton in the

[10] PAC/300, Ralston/5.
[11] PAC/100, Webb/16.
[12] PAC/100, Ralston/10.

2020 TAM to **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** per ton in the 2021 TAM. The Hunter plant saw an increase in delivered coal costs of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** per ton over the prior year, and the delivered coal costs at the Huntington plant increased by **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** per ton.

**Q. What is driving the increase in total delivered coal cost per ton for the Naughton plant?**

A. As a result of the PacifiCorp's plan to convert Naughton Unit 3 to a natural gas resource, PacifiCorp exercised an option of its Naughton coal supply agreement to "reduce the minimum annual tonnage volume quantity in the event of a reduction in coal-fired generation at the plant due to changes in environmental laws or rules."[13]

This provision reduced the annual minimum take-or-pay quantity from **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** tons to **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** tons. PacifiCorp also notes that exercising this provision allowed the Company to avoid the full take-or-pay payment of **[BEGIN CONFIDENTIAL]**[redacted] **[END CONFIDENTIAL]**, and instead pay an environmental shortfall payment of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** for the **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** shortfall tons. Additionally a projected **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** environmental shortfall payment will be owed

[13] PAC/300, Ralston/10-11.

on the **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** shortfall tons on deliveries of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** tons for the period from July 2021 through December 2021. This results in an overall increase to the environmental shortfall payment of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** in the 2021 TAM, from **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** in 2020 to **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** in 2021.

Staff notes that while the delivered cost of coal per ton increased due to volume reductions resulting from the conversion of Naughton Unit 3, the overall delivered cost of coal decreased by **[BEGIN CONFIDENTIAL]**[redacted] **[END CONFIDENTIAL]** when compared with the 2020 TAM.[14]

**Q. Does the Company have any coal supply agreements that expire before the 2021 forecast period begins?**

A. Yes, the Company's current coal supply agreement with Wolverine Fuels, LLC (Wolverine) for the Hunter plant, expires in 2020. Additionally, the Company's coal supply agreement with Rhino Energy, LLC's Castle Valley mine, which is a partial supplier to the Huntington plant also ends in 2020.[15]

**Q. How have the coal supply arrangements for the Hunter and Huntington plant been accounted for in 2021 TAM?**

A. In the 2021 TAM, Hunter coal costs are based upon a "market forward price for Utah coal, as published in Energy Ventures Analysis Fuelcast in November

[14] PAC/300, Ralston/11.
[15] PAC/300, Ralston/14.

2019.[16] As noted above this results in a coal price increase of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** per ton, but a **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** overall change, due to lower volumes.

For the Huntington plant, PacifiCorp states that the coal volume, **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** tons, which had previously been supplied through the Castle Valley coal supply agreement will now be supplied by the Wolverine coal supply agreement "[a]s the Wolverine coal supply agreement is a requirements contract."[17,18] As such, the coal costs at the Huntington plant increased by **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** due to the higher contract costs of the Wolverine coal supply agreement as compared to the expiring Castle Valley contract.

**Q. Does Staff have any concerns with the fueling arrangements for the Huntington plant?**

A. As explained by the Company in response to Staff Data Request 56, the Company entered into the requirements contract for the Huntington plant with Wolverine in 2014.[19] Being a full requirements contract, PacifiCorp was not allowed to renegotiate the agreement or seek additional suppliers for the amount of the expiring Castle Valley agreement. Though certainly the full

[16] PAC/300, Ralston/14.
[17] PAC/300, Ralston/15.
[18] A requirements contract is one in which the supplier agrees to supply as much of a good as is required by the other party, and in return the buyer often agrees to exclusively source the good from the first party.
[19] Staff Exhibit/302, Soldavini/3. PacifiCorp response to Staff Data Request 56.

requirements contract is less preferable to Staff than an agreement that would have provided more flexibility, the coal supply agreement was entered into in 2014, and has been included in power costs since its effect. Staff proposes no adjustment at this time.

**Q. Has the Company included any new coal supply agreements in the 2021 TAM?**

A. Yes, in the 2020 TAM, Staff noted that the Company was involved in negotiations for a new coal supply agreement for its Colstrip plant as a result of an expiring agreement with Western Energy, the previous owner of the Rosebud mine, which supplies coal for the Colstrip plant. In the 2021 TAM, delivered coal prices to the Colstrip plant reflect the new coal supply agreement that was signed December 5, 2019. As a result of this new contract, delivered coal prices increased **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** per ton from **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** per ton in the 2020 TAM to **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** per ton in the 2021 TAM.[20]

**Q. Has Staff reviewed the new coal supply agreement for the Colstrip plant?**

A. Yes. Staff requested a copy of the new coal supply agreement for Colstrip for review in Staff Data Request 60. In response, the Company stated that its coal supply agreements are commercially sensitive and requested special

[20] PAC/300, Ralston/17.

handling.[21] Normally, this would lead to an in-person review of the coal supply agreement. However, due to the current conditions related to the Covid-19 pandemic, reviewing the new coal supply agreement in person was infeasible. Instead, a virtual Skype meeting was held between PacifiCorp and Staff to conduct the review on April 27, 2020.

**Q. Does Staff have any concerns with the new coal supply agreement for Colstrip?**

A. Though it is important to note Staff conducted a relatively brief review in a virtual setting, in Staff's review of the coal supply agreement, it found no terms in the agreement which would lead Staff to conclude the coal supply agreement is imprudent. Staff notes that the contract appears to provide sufficient flexibility for PacifiCorp to adjust its obligations under the contract in response to evolving circumstances.

In review of the coal supply agreement, Staff found **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**. Staff further notes that **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[21] Staff Exhibit/302, Soldavini/5. PacifiCorp Responses to Staff Data Request 60.

[redacted] **[END HIGHLY CONFIDENTIAL]**.

In a 2018 public meeting memo, Staff addressed concerns of potential ratepayer risks in the event of Westmoreland's bankruptcy and found that it posed low incremental risk to PacifiCorp and PGE ratepayers. [22,23] The memo also considered that future coal supply agreements should take into account costs and associated ratepayer risks related to legislation enacted by the governments of another party to the coal supply agreement.[24] **[BEGIN HIGHLY CONFIDENTIAL]**[redacted]**[END HIGHLY CONFIDENTIAL]**.

**Q. Does Staff have a final recommendation regarding third-party coal supply costs?**

A. While Staff has no proposed adjustment at this time, Staff notes that it will continue to actively monitor the Company's future coal supply negotiations, and reserves the right to make a recommendation on this issue based on other parties' testimony.

Staff further notes that the while overall coal costs have decreased due to lower coal generation at the Company's coal plants, the increase in average

[22] Staff Report for Item No. 3 of Regular Agenda at November 21, 2018 public meeting.
[23] Western Energy Company owned the Rosebud Mine and was a division of Westmoreland Coal Company.
[24] The Colstrip plant is owned by five regulated utilities (PacifiCorp, Portland General Electric, Avista, Puget Sound Energy, and Northwestern Energy) and one independent power producer (Talen Energy).

coal costs per MWh highlights the close scrutiny that will be required by the Commission and the Company, to ensure both that economic analysis continues with regard to continued plant operation and the negotiation of any new coal supply agreements is done in a prudent manner, which results in rates that are fair, just and reasonable as coal generation among the Company's coal fleet continues to decline.

## ISSUE 4, NAUGHTON 3 GAS CONVERSION

**Q. Please describe the issue with the Naughton 3 Gas Conversion.**

A. As noted in the Company's Opening Testimony of its concurrently filed GRC, Docket No. UE 374, the Company closed the Naughton 3 coal unit in January of 2019, and plans to convert the unit to a natural gas fueled, slow start peaking unit with a capacity of 247 MW in 2020.[25] As such, in the 2021 TAM, Naughton Unit 3 has been modeled as a natural gas resource. The Company notes that this conversion results in a reduction to NPC of $624,000.[26]

**Q. Does Staff have any issue with the conversion of Naughton Unit 3 to a natural gas resource in the 2021 TAM?**

A. No. Staff has reviewed the Company's proposal, and has no issue with the modeling of the conversion of Naughton Unit 3 in this initial TAM filing.

**Q. Has the Commission deemed the conversion of Naughton Unit 3 to a natural gas unit and its associated cost recovery prudent?**

A. The Commission has acknowledged PacifiCorp's coal action plan in the 2019 IRP, which includes the proposed conversion, but the Commission has not yet deemed the recovery of cost associated with the conversion prudent. The cost of the conversion is included in the Company's GRC, and provided the recovery of costs for the conversion of Naughton Unit 3 is deemed prudent in the GRC, Staff has no further recommendation for this issue at this time.

[25] Docket No. UE 374, PAC/700, Link/77.
[26] PAC/100, Webb/17.

## ISSUE 5, COMPANY SUPPLY SERVICE ACCESS CHARGE

**Q. What is the Company Supply Service Access Charge?**

A. Per OAR 860-038-0720, an electric utility's New Large Load Direct Access (NLDA) program must include a forward-looking rate adder. Customers who elect to return to standard offer or cost-of-service from an NLDA program will be subject to this forward-looking rate adder if their return results in a significant increase to existing cost of service rates. The Company Supply Service Access Charge is PacifiCorp's forward-looking rate adder that customers who elect to be served under the Company's new large load direct access program will be subject to, for four years, if they subsequently decide to return to cost of service and that return results in an increase to existing cost of service customers of more than 0.5 percent.

**Q. How is the Company Supply Service Access Charge calculated?**

A. Per the Company's NLDA tariff, the Company Supply Service Access Charge is calculated as the incremental difference between the four-year levelized cost of capacity that is calculated for avoided cost and the fixed generation costs, Schedule 200. The levelized cost of capacity for the upcoming four years is currently less than the fixed generation costs contained in Schedule 200, and therefore the Company Supply Service Access Charge is $0/MWh.[27]

**Q. Does Staff propose any changes to the Company Supply Service Access Charge?**

[27] PAC/100, Webb/22.

A. No. In a 2019 Staff memo recommending that PacifiCorp's NLDA tariff be allowed to go into effect, Staff indicated it would review the forward looking rate adder methodology in future TAM filings, as the value of the charge is calculated for customers.[28] Because the charge is set at zero, and there are currently no customers in the position to be subject to the Company Supply Service Access Charge, Staff proposes no changes to the calculation, or level of, the charge at this time. Staff will continue to monitor the status of the Company's NLDA program and evaluate the methodology of the Company Supply Service Access Charge in future proceedings as customers elect to participate in the Company's NLDA program.

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

A. Yes.

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[28] Docket No. ADV 900, Staff Report for Public Meeting.

CASE: UE 375
WITNESS: SABRINNA SOLDAVINI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 301

# Witness Qualifications Statements

# May 15, 2020

WITNESS QUALIFICATION STATEMENT

| | |
|---|---|
| NAME: | Sabrinna Soldavini |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Regulatory Analyst<br>Energy Rates, Finance and Audit Division |
| ADDRESS: | 201 High St. SE Ste.<br>100 Salem, OR<br>97301-3612 |
| EDUCATION: | Masters of Science, Agricultural Economics<br>Purdue University, West Lafayette, Indiana<br><br>Bachelor of Science, Economics<br>University of Oregon, Eugene, Oregon |
| EXPERIENCE: | I have been employed by the Oregon Public Utility Commission (Commission) since August 2018 in the Energy, Rates and Finance Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues for filings made by utilities.<br><br>Prior to working for the Commission I was a consulting analyst for MGT Consulting, primarily to help large public school districts prepare for bond proposals through budget analysis and statistical modelling/projections of student and demographic data. Prior to this work, I was a Research Assistant at Purdue University where I conducted research on the economic feasibility of biofuel feedstocks. Additionally, I have experience working in Data Analysis, and Program Coordination within the technology sector. |

CASE: UE 375
WITNESS: SABRINNA SOLDAVINI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 302

## Exhibits in Support
## Of Opening Testimony

**May 15, 2020**

**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.

**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.

**OPUC Data Request 56**

Did PacifiCorp explore other options to supply the Huntington plant given the expiration of the Castle Valley coal supply agreement in 2020? If so, please provide any evidence. If no, please explain why not.

**Response to OPUC Data Request 56**

The Castle Valley coal supply agreement (CSA) expires on December 31, 2020. The other CSA at Huntington plant with Wolverine is a full requirements contract that was executed December 12, 2014 which has a specific provision allowing for coal deliveries to continue under the legacy Castle Valley CSA through its expiration date. Since the Wolverine CSA is a full requirements contract, no replacement for the Castle Valley CSA is allowed.  All coal deliveries to the plant beginning January 1, 2021, will be under the Wolverine CSA.

**OPUC Data Request 57**

Why has PacifiCorp chosen to replace the Castle Valley coal supply agreement by increasing the volume requirements of the Wolverine coal supply agreement given that "the purchase under the Wolverine coal supply agreement has a higher cost than the expired Castle Valley coal supply agreement"?

(a) Did the Company seek to renegotiate the price of the Wolverine contract or to re-enter into a coal supply agreement with Castle Valley?

**Response to OPUC Data Request 57**

(a) Please refer to the Company's response to OPUC Data Request 56.

**OPUC Data Request 60**

Please refer to PAC/300, Ralston/17. Please provide the new coal supply agreement for the Colstrip plant that was signed December 5, 2019.

**Response to OPUC Data Request 60**

PacifiCorp's coal supply agreements (CSA) are commercially sensitive. PacifiCorp requests special handling. Please contact Ajay Kumar at (503) 813-5161 or ajay.kumar@pacificorp.com to make arrangements for review.

CASE: UE 375
WITNESS: Kathy Zarate

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 400

# Opening Testimony

# May 15, 2020

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

A. My name is Kathy Zarate. I am a Utility Economist employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

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

A. My Witness Qualification Statement is found in Exhibit Staff/401.

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

A. The purpose of my testimony is to summarize analysis and recommendations on certain issue regarding PacifiCorp's 2021 Transition Adjustment Mechanism (TAM) filing, Docket No. UE 375.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. I prepared the following exhibits:

- Staff/401: Witness Qualification Statement
- Staff/402: PacifiCorp's Responses to Staff Data Request Nos. 46, 48, 110, 111, 113 and 114
- Staff/403: PacifiCorp's Confidential Responses to Staff Data Request Nos 43, 44, 45, 47, and 109.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

**Q. What issues does your testimony address?**

A. The issues covered in this testimony are standard inputs that are used in power cost modeling, and two power cost issues; namely –Utility wheeling expense and qualifying facility purchased power expense.

**Q. Please summarize your recommendations in this case.**

A. I am recommending one adjustment related to PURPA purchase power costs. The adjustment is a **[Begin Confidential]** [redacted] **[End Confidential]** reduction to Net Power Costs. This adjustment removes the effect from PacifiCorp's history of consistently over-forecasting each of this category of costs. Staff made similar adjustments in the prior year's proceeding. Staff is basing its recommendations using the same analytical approach as used in previous dockets.

I am also recommending the Commission order PacifiCorp to return its power cost models with the appropriately adjusted minimum operating condition for Jim Bridger Units 3 and 4 if the Commission disallows full cost recovery for these capital additions.

## ISSUE 1. STANDARD INPUTS

**Q. Please summarize this issue and Staff's recommendation.**

A. Standard inputs refer to various cost items associated with operating power plants and other sources of power. The standard inputs for review are heat rates, forced and scheduled maintenance outages, natural gas price forecasts, Official Forward Price Curves (OFPC), fuel prices and minimum operating levels. In general, except as specified below, Staff has reviewed the inputs and identifies no issues or recommendations for additional analysis or adjustments at this time, with the exception of the minimum operation levels at Jim Bridger Units 3 and 4.

**Q. Please discuss Staff's concern with Jim Bridger Units 3 and 4 minimum operation levels.**

A. I do not currently have any adjustment for the minimum operating levels of PacifiCorp generation, but note that an adjustment may be necessary depending on the Commission's determination on the prudence of environmental upgrades sought for cost recovery in this case, including Jim Bridger Units 3 and 4. In PAC/100, Webb/17, lines 3-11, the witness states that PacifiCorp has set for its GRID runs with the minimum operating levels taking into account the environmental upgrades that were installed for Jim Bridger Units 3 and 4. This is different from the prior TAM cases where the Commission adopted TAM rates that assumed minimum operating levels without environmental upgrades. The fact that PacifiCorp changed its approach in this TAM is understandable given that PacifiCorp is seeking rate recovery approval of those environmental upgrades in UE 374. However, depending on the Commission's determination of the prudence of those upgrades, the minimum operating levels will need to be set consistent with that Commission decision. Therefore, I recommend the Commission direct the Company to revise its minimum operating levels and restate power costs should the Commission exclude environmental upgrades from rate recovery.

## ISSUE 2. WHEELING

**Q. Please describe and discuss the wheeling expense.**

A. Wheeling expenses are expenses the PacifiCorp incurs at the wholesale level from delivering power to PacifiCorp's distribution system. PacifiCorp pays different utilities Open Access Transmission Tariff (OATT) rates when PacifiCorp is transporting power to its distribution system. PacifiCorp development a transmission wheeling expense estimate that adds to power costs. Staff is not aware of any complex separate transmission modeling that PacifiCorp uses solely to develop a wheeling expense estimate. The PacifiCorp transmission wheeling expense testimony is comprised on three lines, PAC/100, Webb/16, lines 19-21.

In PAC /100, Webb/ 11, Figure 2, PacifiCorp identifies changes from the 2020 TAM baseline related to wheeling expenses. PacifiCorp is projecting an $8 million increase in wheeling expenses. PAC/100, Webb/16, lines 19-21, explain that the $8 million (Total Company) represents the cost of the CAISO nodal modeling the CAISO is building for PacifiCorp. This $8 million cost component was discussed and subject to a Memorandum of Understanding in the PacifiCorp inter-jurisdictional cost allocation process.[1]

**Q. Do you have any objection to the $8 million total Company change in costs relating to the CAISO modeling for nodal pricing?**

[1] See Order 20-024, Page 8

A. I do not.[2]

**Q. Have you reviewed the PacifiCorp proposed wheeling expense for this TAM filing?**

A. Yes. The data requests related to several years of wheeling expense data (2015-2019) as compared to Company forecasts.

**Q. Have you compared the 2020 TAM Order amounts for wheeling to the PacifiCorp proposal in this case?**

A. Yes. The 2020 TAM settlement, which the Commission adopted, has Total-Company wheeling expense of **[Begin Confidential]** [redacted][3] **[End Confidential]**. The 2021 PacifiCorp has proposed TAM wheeling amounts of **[Begin Confidential]** [redacted] **[End Confidential]**. If you subtract **[Begin Confidential]** [redacted] **[End Confidential].** While typically settlement values are strictly for purpose of settling that specific docket and does not have precedential value, I am just noting the relationship of the Commission's adopted value and PacifiCorp's projection for 2021.

**Q. How do the PacifiCorp's projections compare to actual total Company wheeling costs?**

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[2] See Staff/100 for a discussion of the Nodal Pricing Model.
[3] Order No.19-351, Appendix A, page 19 of 45, line 22.
[4] See Exhibit PAC/101, Webb/1, line 22.

A. The table below provides such a comparison.[5]

*Table 1 – Confidential*

**[Begin Confidential]**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| [redacted] | | | [redacted] | | | | |
| | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |

**[End Confidential].**

**Q. What do you observe from the table above?**

A. Two observations come to mind. First, PacifiCorp does not appear to have a good track record of accurately forecasting wheeling expenses. Second, PacifiCorp has a history of overestimating its total wheeling costs.

Using the most three recent years, PacifiCorp over forecasts its wheeling expenses by 2.5 percent. Even so, the 2019 actual Wheeling costs was well above the forecasted level.[6] In addition, given that PacifiCorp is incurring an $8 million modeling charge from CAISO which is a new expense that makes PacifiCorp's 2021 wheeling expenses forecast appear reasonable.

**Q. Do you have a wheeling expense adjustment?**

[5] See Exhibit PAC/101, Webb/ Confidential Table 3 and Staff data request N0. 109
[6] Data Request from Company to Staff N0. 109

A. No. Staff does not have an adjustment regarding PacifiCorp's projected 2021 wheeling expense. In looking over the data, the actual three-year average of wheeling expenses, the general over-forecasting of wheeling expense, and PacifiCorp's 2021 wheeling cost projection, I do not have an adjustment to wheeling expense at this time.

## ISSUE 3. PURPA

**Q. Please discuss Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA).**

A. PURPA requires investor-owned utilities to purchase power from Qualifying Facilities (QFs) using rates established by the state regulatory commissions like the Oregon PUC.

**Q. Did PacifiCorp change the methodology of forecasting PURPA costs in UE 375?**

A. No. It is Staff's understanding that PacifiCorp did not change its methodology, from the 2019 TAM.

**Q. Did Staff ask PacifiCorp how its projections of QF purchased power costs compare to actuals?**

A. Yes. Staff Data Request No. 43 asked PacifiCorp to provide its actual and projected QF purchase power costs for the years 2015 through 2019.[7] Staff Data Request No. 45, asked PacifiCorp to provide its projected QF purchase power costs for the years 2017 through 2019.[8] Table one below, created based on the information provided by PacifiCorp on these responses.

[7] Data Request from Company to Staff N0. 43
[8] Data Request from Company to Staff N0. 45

*Table 2-Confidential*

**[Begin Confidential]**

| | | | |
|---|---|---|---|
| | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| | | | |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | | | |
| | | | |
| [redacted] | [redacted] | [redacted] | [redacted] |

**[End Confidential].**

**Q. What do you conclude from Table 1?**

A. In the case of QF purchases, as Staff found in the 2019 TAM, PacifiCorp consistently overestimates its QF purchase power cost. Over the 2017 through 2019 time-period, the average level of overestimation is roughly four percent. Given that PacifiCorp has not identified in testimony any change in approach for estimating QF power costs, there is no reason to assume that the consistent overestimation has been rectified and is not present for the 2021 QF power cost forecast.

**Q. Given this consistent over-forecasting on QF purchased power costs, what is your adjustment?**

A. My Adjustment is four percent of the projected 2021 QF purchased power cost. Inasmuch as PacifiCorp projects its 2021 QF total company purchased power cost to equal **[Begin Confidential]** [redacted] **[End Confidential]** the recommended downward total company adjustment is 4 percent of that total or **[Begin Confidential]** [redacted] **[End Confidential].**

Using PacifiCorp's projected 2020 SG factor of 26.023, from line 1 of Exhibit PAC/101, Webb/1, I obtain an Oregon allocated adjustment of **[Begin Confidential]** [redacted] **[End Confidential]** reduction to Net Power Costs.

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

A. Yes.

CASE: UE 375
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION
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# OREGON

# STAFF EXHIBIT 401

# Witness Qualifications Statement

**May 15, 2020**

**WITNESS QUALIFICATION STATEMENT**

| | |
|---|---|
| NAME: | Kathy Zarate |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Utility Economist<br>Energy Rates, Finance and Audit Division |
| ADDRESS: | 201 High Street SE., Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | Bachelor of Arts, Economics<br>Oregon State University, Corvallis, Oregon<br><br>Bachelor Degree in Law<br>Republic University, Santiago, Chile |
| EXPERIENCE: | I have been employed by the Public Utility Commission of Oregon since April 2016, with my current position being a Utility Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals.<br><br>I have approximately 10 years of professional experience in contracting and audit review work, including:<br><br>• Six years as contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business delivery, and investigating property theft. |

CASE: UE 375
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION
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## STAFF EXHIBIT 402

## Exhibits in Support
## Of Opening Testimony

## May 15, 2020

UE 375/PacifiCorp
May 11, 2020
OPUC Data Request 110

**OPUC Data Request 110**

**Wheeling**
For calendar years, 2016 through 2020 YTD, for each year, please provide actual wheeling cost and actual wheeling revenues.

**Response to OPUC Data Request 110**

(a) Please refer to Attachment OPUC 110-1 for actual wheeling expenses for 2016 through March 2020.

(b) PacifiCorp objects to this data request as overly broad, requesting information that is outside the scope of this proceeding, and not reasonably calculated to lead to admissible evidence. Wheeling revenues are not included in the transition adjustment mechanism. Without waiving any of the aforementioned objections, the Company responds as follows:

Please refer to Attachment OPUC 110-2 for actual wheeling revenues for 2016 through March 2020.

UE 375/PacifiCorp
May 11, 2020
OPUC Data Request 111

**OPUC Data Request 111**

**Wheeling**
Please identify and describe any one-time events that could impact transmission wheeling cost or revenues project for 2021. Herein please consider such events as projected to occur in 2021, or that could occur prior to 2021, yet still impact 2021 projections.

**Response to OPUC Data Request 111**

To the extent this data requests seeks information about wheeling revenues, PacifiCorp objects to this data request as overly broad, requesting information that is outside the scope of this proceeding, and not reasonably calculated to lead to admissible evidence. Without waiving any of the previous objections, PacifiCorp responds as follows:

Wheeling costs and revenues may change when wheeling tariff rates are updated by counterparties. The Company has included the most recent tariff rates in the 2021 transition adjustment mechanism (TAM) initial filing and will continue to evaluate the impacts of any tariff rate changes included in the 2021 TAM during the course of this proceeding.

UE 375/PacifiCorp
May 12, 2020
OPUC Data Request 113

**OPUC Data Request 113**

**Transmission**
Does PacifiCorp currently have, or anticipate to file, a transmission rate change before FERC? If yes, please provide the identification for the transmission rate case and describe its key elements and cost drivers.

**Response to OPUC Data Request 113**

PacifiCorp objects to this data request as overly broad, requesting information that is outside the scope of this proceeding, and not reasonably calculated to lead to admissible evidence. Without waiving any of the previous objections, PacifiCorp responds as follows:

(1) Transmission Formula Rates.

With one exception discussed below, PacifiCorp does not intend to change its current transmission formula rate, but PacifiCorp will update the applicable charges to be effective June 1, 2020. Additional background and discussion is provided below.

On May 23, 2013, the Federal Energy Regulatory Commission (FERC) approved a settlement agreement in Docket No. ER11-3643-000, which implemented a formula transmission rate for PacifiCorp to calculate its rates for Point-to-Point Transmission Service and Network Integration Transmission Service. Among other items, the settlement agreement provided that such charges would be updated annually.

Thus, on May 15, 2020, PacifiCorp will submit its 2020 Transmission Formula Rate Annual Update (Annual Update) as required under Section I.3(e) of Attachment H-2, "Formula Rate Implementation Protocols" (the "Protocols"), of PacifiCorp's Open Access Transmission Tariff (OATT). As provided in the Protocols, the Annual Update is an informational filing to the FERC.

As noted earlier, the annual updated charges are effective June 1st. The calculation in this Annual Update includes inputs from PacifiCorp's 2019 FERC Form No. 1 (filed on April 10, 2020), as well as limited projections of current calendar year transmission plant forecasted for the applicable Rate Year.

Regarding formula rates, the FERC has stated that "the formula itself is the rate" and "thus, periodic adjustments, typically performed on an annual basis, made in accordance with the Commission-approved formula do not constitute changes in the rate itself..." *Ocean State Power II*, 69 FERC ¶ 61,146, at 61,544 (1994). Thus, the Annual Update is not a change to the rate itself.

The exception noted earlier regards FERC Order No. 864. *Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes*, 169 FERC ¶ 61,139 (2019). On November 21, 2019, the FERC issued Order No. 864, which sets forth requirements for public utility transmission providers with transmission formula rates to account for changes caused by the Tax Cuts and Jobs Act of 2017.

Order No. 864 requires public utilities with transmission formula rates to include in their formula rates: (i) a mechanism to deduct any excess ADIT from or add any deficient ADIT to their rate bases (the "Rate Base Adjustment Mechanism"); (ii) a mechanism that decreases or increases their income tax allowances by any amortized excess or deficient ADIT, respectively (the "Income Tax Allowance Adjustment Mechanism"); and (iii) a new permanent worksheet that will annually track information related to excess or deficient ADIT and will contain five categories of information (the "ADIT Worksheet"). Finally, Order No. 864 requires each public utility with transmission formula rates to submit a filing to demonstrate compliance with Order No. 864 within the later of 30 days of the order's effective date or its next annual update following the issuance of Order No. 864. In compliance with the above, PacifiCorp will be making a compliance filing on or before May 15, 2020 to incorporate the three enumerated changes to its transmission formula rate.

(2) Ancillary Services Rates

PacifiCorp currently anticipates making a filing at FERC to implement new ancillary services rates under Schedules 2, 3, 3A, 5, and 6 of its Open Access Transmission Tariff. Ancillary service rates for Schedules 3, 3A, 5 and 6 were last established in Docket No. ER17-219 through a settlement agreement accepted by the FERC on April 19, 2018. Schedule 2 rates were established in Docket No. ER11-3643 through a settlement agreement accepted by the FERC on May 23, 2013.

As a part of the settlement agreement in Docket No. ER17-219, a rate moratorium period was established that ends on July 1, 2020. In compliance with the terms of settlement agreement, PacifiCorp has worked with interested parties and signatories to the settlement agreement to try to reach a consensus on a number of issues. Under the settlement agreement, new rates can become effective beginning July 1, 2020.

UE 375/PacifiCorp
May 12, 2020
OPUC Data Request 113

PacifiCorp is currently finalizing the rates to be proposed for FERC acceptance and, therefore, is unable at this time to provide a summary of the primary drivers for the changes in rates.

UE 375/PacifiCorp
May 12, 2020
OPUC Data Request 114

**OPUC Data Request 114**

**Transmission**
For the calendar years 2016 through 2020 YTD, Please describe any discussions or resolutions with BPA on the Idaho exchange and impacts on PacifiCorp wheeling cost or transmission revenues.

**Response to OPUC Data Request 114**

PacifiCorp assumes this request regards the potential Idaho Power Company asset purchase and sale. Based on the foregoing assumption, the Company responds as follows:

No discussions were held specifically with Bonneville Power Administration n calendar years 2016 to 2020 YTD regarding the potential Idaho Power Company asset purchase and sale.

CASE: UE 375
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 403

## Exhibits in Support
## Of Opening Testimony

**May 15, 2020**

**STAFF EXHIBIT 403**

**INCLUDING 2 EXCEL SPREADSHEETS**

**ARE CONFIDENTIAL AND SUBJECT TO**

**PROTECTIVE ORDER NO. 16-128**