CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

May 24, 2023

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

A. My name is Julie Jent. I am a Senior Economist employed in the Energy Costs Section of the Rates, Safety and Utility Performance (RSUP) 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 am Staff's summary witness. I present an overview of Portland General Electric Company's (PGE or Company) 2024 Annual Update Tariff (AUT) filing, put PGE's forecasted Net Variable Power Costs (NVPC) into perspective by contrasting them with the final forecast of NVPC in the 2023 AUT, and present an overall recommendation for Commission consideration. I also introduce the Staff providing testimony regarding calculation of PGE's NVPC and present a summary of the adjustments and recommendations made by all Staff.

Second, I address PGE's California-Oregon Border (COB) trading margin proposal. My recommendations regarding PGE's NVPC, along with other Staff recommendations, may change based on further review and based on the testimonies offered by other parties.

It is important to note that AUT-related topics are also addressed in Staff's opening testimony to be filed regarding PGE's general rate request (GRC). One example of this is the Qualifying Facilities (QF) pass through which is addressed in Staff/1300. This is because changes to the AUT itself are not addressed in the NVPC proceedings and are appropriately addressed in an independent proceeding such as a GRC. In addition to this testimony, I will file GRC testimony in this docket regarding proposed changes to the AUT, PGE's proposed changes to PGE's Power Cost Adjustment Mechanism (PCAM), as well as other non-power cost testimony on other topics included in this year's GRC.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits: PGE's non-confidential responses to select data requests can be found in Exhibit Staff/102, PGE's confidential responses to select data requests can be found in Exhibit Staff/103, and PGE's highly confidential responses to select data requests can be found in Staff Exhibit/104.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ANNUAL UPDATE TARIFF OVERVIEW

Q. What is the AUT?

A. In Order No. 07-015, the Commission adopted the AUT and annual PCAM for PGE. The AUT is designed to allow PGE to annually revise customer rates to reflect certain changes in its projected net variable power costs. Schedule 125 lists the costs and revenues that PGE includes in the calculation of its NVPC. The updated power cost forecast is then used as the baseline for comparing actual net variable power costs when PGE applies the Power Cost Adjustment Mechanism (PCAM) set forth in PGE's Schedule 126. PGE uses its MONET model to develop its NVPC forecast.[1]

Q. Are there particular requirements for AUT filings?

A. Yes. The AUT itself sets forth the particulars of the annual update, specifying what can be updated and when. In addition, there are Minimum Filing Requirements (MFRs) established through Commission Order No. 08-505. PGE includes an exhibit in its testimony with a general list of supporting documents and workpapers to be included in MFR volumes.[2] Commission Order 08-505 did not contemplate supporting documents and workpapers regarding ancillary services (i.e., Volume 8) and energy storage (Volume 9).

Q. Does the Company comply with Order No. 22-427 adopted in 2022?

A. It is not entirely clear. In the order, the following requirements were applicable for the 2023 and 2024 AUT. One, "[i]n anticipation of PGE's participation in

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[1] *See In the Matter of Portland General Electric Company*, UE 215, Order No. 10-410 (October 20, 2010) (Commission describing AUT).

[2] See PGE/301 pages 1-4 for a list of MFRs. See also Order No. 08-505 (UE 198) (2009 GRC).

CAISO EDAM in 2024, PGE will provide written quarterly updates at Quarterly Power Supply Updates in 2023 and hold workshop prior to 2024 AUT regarding resource sufficiency evaluation, greenhouse gas accounting and costs, and transmission impacts and potential costs and benefits from EDAM participation, based on most recently available information."[3] This was completed on February 22, 2023.

Two, "PGE will file deferral application by November 30, 3022, to record any potential Revenue Distribution Clause money received from Bonneville Power Administration (BPA) for 2022 fiscal year and for variance associated with change to BP-22 transmission rates. PGE will amortize the deferral in 2024 AUT filing."[4] PGE filed the required request for deferral on November 22, 2022.[5] The Commission has not yet considered the request. Staff assumes that PGE has yet proposed to amortize the deferral because it is not yet approved. However, if the deferral is approved prior to the Final NVPC Update, PGE will be able to amortize the deferral in this AUT filing as ordered.

Q. Please summarize PGE's 2024 AUT filing.

A. PGE's NVPC forecast is included in its GRC filing this year. The Company has forecasted 2024 Net Variable Power Costs (NVPC) of $860.1 million in its initial filing.[6] This is an increase of approximately $129.9 million, or 17.78 percent,

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[3] *In the Matter of Portland General Electric Company 2023 Annual Power Cost Update*, Order No. 22-427, App. A, p. 3, UE 402, (November 1, 2022).
[4] Id., App. A, p. 6.
[5] *In the Matter of Portland General Electric Company Application for Deferred Accounting,* UM 2263 (November 29, 2022).
[6] *See* PGE/300, Schwartz—Outama—Cristea/1.

over the final 2023 NVPC forecast.[7] PGE points to the following as drivers: An increase in each of the costs of gas, hydro, and coal; an increase in generation from Power Purchase Agreements (PPAs),[8] an expected 72 MWa load increase, and an increase in market and contract purchases.[9] See CONF Table 1 below for a more detailed description of this change in millions, MWh, and $/MWh from PGE's workpapers; those large changes are highlighted in yellow.[10] Please note, the numbers in CONF Table 1 are from the initial filing on February 15. The updated total on April 1 was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

CONF TABLE 1. NVPC FORECAST FOR 2024 AUT

[BEGIN CONFIDENTIAL]

7 PGE/300, Schwartz—Outama—Cristea/55; See Table 9 (Non-Confidential).
8 This is mostly due to contracted Variable Energy Resources (VERs) cost and performance which are discussed more below.
9 PGE/300, Vhora-Outama-Cristea/2.
10 This is reformatted and pasted from CONF WorkPaper_Table 9 Comparison_NVPC.

[redacted]

[END CONFIDENTIAL]

Q. How have the Company's System load and cost changed over time?

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[11] See WorkPaper_Table 9 Comparison_NVPC for 2023 and 2024 forecasted numbers. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

[redacted]

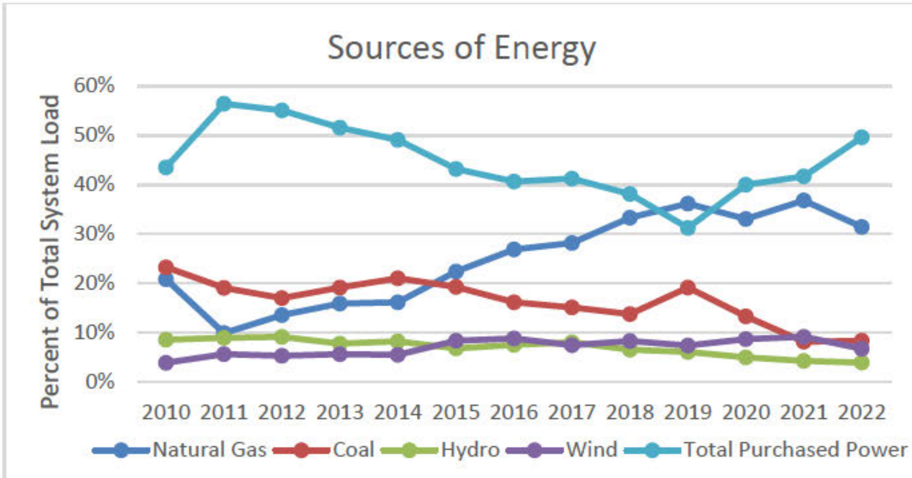
[redacted]

[END HIGHLY CONFIDENTIAL]

Q. How have the Company's Sources of Energy Changed over time?

A. PGE's resource mix has remained relatively stable for most categories outside of coal (decreased), natural gas (increased) and purchased power (increased). Total purchased power is comprised of purchased hydro, wind, and solar, in addition to term purchases, spot purchases, and source not specified.

FIGURE 2. SOURCES OF ENERGY AS A PERCENT OF LOAD[12]



Q. How have the Company's expenses changed since last year's filing?

A. The largest effects on the 2024 increase are both gas cost and performance and VER Cost and performance. In addition, the forward energy price curves and an expected increase to load, compared to the final 2023 forecast, attribute to some of the increase seen below in Table 2.[13] However, much of the increase is related to a few specific proposals for gas and the addition of new VER contracts, which are detailed below and are contentious.

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12 See Staff/103, PGE response to DR 169 Attachment A (electronic spreadsheet) which provides sources of energy and capacity based on information included within PGE's Securities and Exchange Commission (SEC) Form 10-K Annual Reports.

13 See Table 9 in PGE/300 Schwartz—Outama—Cristea/55 (non-confidential).

TABLE 2. FORECAST POWER COST DIFFERENCE 2023 VS. 2024

Forecast Power Cost Difference 2023 vs. 2024 ($ Millions)	
Factor	Effect ($M)
Hydro Cost and Performance	$ 9.3
Coal Cost and Performance	$ 0.8
Gas Cost and Performance	$ 62.4
VER Cost and Performance	$ 24.8
Contract and Market Purchases	$ 14.8
Market Purchases for Load Increase	$ 14.3
Transmission	$ 3.4
Total	**$ 129.8**

** Numbers may not total due to rounding.*

Q. Why are the gas costs forecasted so much higher in 2024?

A. Gas costs in totality encompass not just those thermal generators that are owned by PGE and have increased in the aggregate from the 2023 AUT. Gas costs, as referred to in Table 2, are a composite of a few different subcategories of costs that can be seen below in CONF Table 3. As seen from the table below **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

CONF TABLE 3. GAS COST FORECASTED CHANGE FROM 2023 TO 2024[14]

[BEGIN CONFIDENTIAL]

14 This information was derived from CONF WorkPaper_Table 9 Comparison_NVPC.

[redacted]

[END CONFIDENTIAL]

Q. Explain the terms used in CONF Table 3 above and the forecasts.[15]

A. "Total Gas" represents the fuel cost at all PGE owned gas generating units. "Gas Resale Value" estimates the potential net power cost benefit that could be realized from gas sales and purchases at the Gas Transmission Northwest (GTN) pipeline that fuels the Carty and Coyote plants. The change between the 2023 and 2024 forecasts relates to the updates in forward price curves that impact the MONET dispatch of Carty and Coyote and the proposed enhancement related to the GTN pipeline availability.[16]

The "Estimated Premium for Gas Option" is for a proxy contract for a physical gas call option that PGE states will protect PGE and customers from gas price excursions risks during 2024 winter months.[17] Inclusion of this type of

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[15] *See* Staff/103, PGE response to CONF DR 585 (pdf). The figures above in Table 3 are confidential, however the descriptions of the terms which are mentioned below are found in the public (non-confidential) version of PGE's testimony starting on PGE/300, Schwartz—Outama—Cristea/34.

[16] *See also* PGE Exhibit 300, Section III.D for a description of the gas resale optimization. Also see MFRs submitted on March 1, 2023 Vol 3 – Thermal/Therma Plant Gas Resale, and Vol 10 – New Items and Enhancements\Step 00f – Gas Resale Pipeline Deration.

[17] *See also* PGE Exhibit 300, Section III.F.1 for a description of PGE's proposal regarding the 2024 gas call option contract. Also see MFRs submitted on March 1, 2023, Vol 10 - New Items and Enhancements\Step 00m - Winter Gas Call Option. "Step 00m - Winter Gas Call Option" in MFR Vol 10 – New Items and Enhancements.

contract is something that has not been done in previous AUTs. Staff discusses PGE's proposed inclusion in Staff/300.

"Total Gas Transport and Storage" represents the gas transportation costs for delivery from gas pipelines and the monthly fee due to Northwest Natural for use of the North Mist storage facility.

"Gas Financials" represent the gain or loss on financially settled transactions to hedge gas price fluctuations. The year over year change is driven by the changes in forward price curves. The Canadian Foreign Exchange Rate Hedge Contracts are also updated every MONET update in this case.[18]

Q. Why are the VER[19] costs mentioned above forecasted so much higher in 2024?

A. **[BEGIN CONFIDENTIAL]** [redacted]

[18] *See* MFRs submitted on March 1, 2023, Vol 1 - Forward Curves\FX Curve.

[19] These are resources such as wind and solar, which have variable supply and are not guaranteed as available when called upon. Read more at https://crsreports.congress.gov/product/pdf/IF/IF11257.

[redacted] [END CONFIDENTIAL]

CONF TABLE 4. HIGH-COST CONTRIBUTOR PPAS

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Can you provide additional context on the resources mentioned above?

A. Yes. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[BEGIN HIGHLY CONFIDENTIAL] [redacted]

[20] See Staff/103, PGE CONF Response to DR 381 (pdf) and DR 381 Attachment A. Response to DR 381 was classified as non-confidential but because the attachment was CONF, Staff is erring on the side of caution and using CONF status for DR 381 as well. See also Staff/103 which detail information included on each PPA in MFRs Vol. 5 Contracts.

[21] The information to create CONF Table 4 was derived from CONF WorkPaper_Table 9 Comparison_NVPC. In addition, PGE's response to DR 381 was also CONF.

[redacted][22] **[END HIGHLY CONFIDENTIAL]**

Q. Does the Company include modelling changes in this filing?

A. Yes.[23] The Company has proposed several modelling enhancements in its filing including:

- Schedule 125 Guidelines Update,
- Capacity Planning,
- Washington Cap-and-Invest Program,
- Gas Resale and Storage Modeling,
- 2024 Gas Physical Call Option,
- California Oregon Border (COB) Trading Margin Refinement,
- Extended Day-Ahead Market (EDAM) Update, and
- QF Pass-Through mechanism.

Q. Which modeling changes are addressed in Staff's Opening Testimony for this year's AUT filing?

A. This testimony addresses the COB trading margin refinement in Issue 2. Ishraq Ahmed addresses the Washington State Cap-and-Invest Program in Staff/200. Curtis Dlouhy addresses capacity planning, gas resale and storage modeling, and the 2024 gas physical call option in Staff/300.

Q. Does Staff address power cost issues in their GRC testimony?

[22] See UM 1953 Order No. 23-036 and Order No. 23-035 for more information. There are non-confidential, confidential, and highly confidential versions of the Staff Report and subsequent order.

[23] *See* PGE/300 Schwartz—Outama—Cristea/9.

A. Yes, in the GRC Opening Testimony, the three remaining power cost proposals are addressed. The QF pass thru proposal is addressed in Staff/1000, Issue 1. The schedule 125 guidelines update and EDAM is addressed in Staff/400.

Q. Are further updates expected in the docket?

A. Yes. PGE will update its NVPC forecast in this proceeding. PGE will file an updated informational forecast of NVPC in July and October with updated inputs for power, fuel, and transmission contracts and their related costs, outage forecasts, loads, and the power, gas and California Carbon Allowance (CCA) forward price curves. In November PGE will file its final forecast of NVPC with final updates to power, gas, and CCA forward price curves, various power, fuel, and transmission contracts and their related costs, long-term customer opt-outs, and Qualifying Facility (QF) commercial operation dates.

Q. Does Staff have any additional comments to make regarding this year's AUT Filing?

A. Yes, Staff is concerned about the ongoing use of the MONET model in this AUT filing and future filings. This concern is juxtaposed with the change from the GRID forecasting model to the Aurora model that PacifiCorp has been making since 2021.[24]

Q. What concerns does Staff have?

A. MONET has a variety of shortcomings that have been further exposed as Staff has worked through this year's AUT filing. These include the following:

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[24] *See* UE 390 PAC/100, Webb/23, lines 12-17. *See also* UE 400 PAC/100, Wilding/15.

1. MONET is a single stage model and does not represent the friction between the day ahead and real time market. This is especially pronounced in the treatment of wind resources and overgeneration, which can be monetized but not accounted for in MONET. It is worth noting that PacifiCorp has a Day-Ahead/Real-Time (DA/RT) adjustment, which Staff and stakeholders are not supportive of in its current form. As such, any proposals for a DA/RT adjustment should keep this in mind.
2. Many items such as the RCE forecasted costs, the Washington Cap and Invest costs, the COB trading margin, and the Winter Gas call option are all calculated outboard—sometimes roughly—and modeled in MONET simply as additional costs that are not optimized within the model.[25]
3. It is essential to assess power costs as granularly as practicable, and the Company's current MONET framework often uses monthly average prices to make hourly decisions. In the case of the COB trading margin and the SUMAS gas price, the Company calculates power costs where these are monthly on-and-off peak averages. This creates a mismatch between monthly COB prices and hourly dispatch,[26] although, there is a load and solar shape that does

[25] See Staff/102, PGE Response to DR 371 (pdf). See also the MFRs submitted by PGE on February 15, 2023, Vol 10 – New Items and Enhancements. In these MFRs, PGE provides detailed information regarding each enhancement.
[26] *See* Staff/102, PAC response to DR 378 (pdf) and DR 380 (pdf).

integrate some distribution of energy based on time of day/time of year/randomness.

4. By the time the model runs, these prices, loads, and VER outputs are accepted in their entirely, so there's not really a way to assess randomness or do a Monte Carlo simulation.[27] This is something that many modeling software, such as AURORA which is used by PacifiCorp and Idaho Power, are capable of doing.
5. There is a gap between how PGE dispatches its thermal plants in actual operations versus the economic dispatch in the MONET model. There is a disconnect between forecast market sales and purchases during summer months between the forecast and actual operations.[28]

1. Lastly, "The regional market is experiencing transmission-related constraints which MONET is currently not set up to address"[29]

Q. Does PGE have any experience with other models?

A. Yes. "PGE uses AURORA in conjunction with other models for the Integrated Resource Planning (IRP) and Clean Energy Plan (CEP) modeling. Please see modeling details in PGE's 2023 CEP/IRP, Appendix H.[30] For IRP modeling, PGE also uses multiple Excel models, the Sequoia Simulation Model, and ROSE-E capacity model. PGE Power Operations uses ABB/Hitachi's Portfolio

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[27] A Monte Carlo simulation is a technique that uses random sampling to estimate the possible outcomes of an uncertain event or process. It is based on a mathematical method that involves repeated experiments with different scenarios.

[28] *See* Staff/102, PGE Response to DR 376 (pdf). See also PGE/300 Pages 17, lines 13-22 and pages 21-23.

[29] PGE/300, Schwartz—Outama—Cristea/13.

[30] https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-resources-materials.

Optimization to model the shorter-term (within the month) operational horizon."[31] Because PGE has familiarity with other modeling software such as Aurora, switching from MONET to a different model may lead to greater consistency between planning and implementation, fewer calculations done outside of the model, and greater accuracy for power cost forecasts, given the granularity of other models.

Q. To Staff's knowledge, has the Company considered moving away from using MONET to estimate power costs?

A. Yes. "PGE is currently considering options to enhance the modeling of the NVPC forecast, including new modeling software or methods other than MONET."[32] Knowing PGE is considering the use of different models leads Staff to conclude that PGE also sees the inadequacies found in MONET and is interested in ensuring they use a model that better predicts power costs.

Q. Please summarize all Staff's adjustments related to the issues covered in this year's AUT filing.

A. In Staff/100, Staff proposes: 1. PGE consider the use of a different model in their NVPC forecast. 2. A 30 percent increase in COB benefits, which would result in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** adjustment to their NVPC.

In Staff/200, Staff does not have any recommendations or adjustments at this time and will continue to monitor any changes to the carbon

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[31] *See* Staff/102, PGE response to DR 530 (pdf).
[32] *See* Staff/102, PGE response to DR 531 (pdf).

obligations. There are some concerns how carbon allowances will contribute to the overall NPC.

In Staff, Staff proposes: 1. Reduce NVPC by $325,000 by assuming some delivered gas availability November-March instead of the Company's proposal to assume 0 delivered gas. 2. Reduce NVPC by 2.2 million by rejecting the gas call option contract. 3. Reduce NVPC by $1.6 million to reflect recommended changes to the Company's RCE forecast.

Q. What concerns have been raised by the public concerning power costs and the proposed rate increase in UE 416?

A. Staff has received two aggregate concerns via email. One, commenters expected solar and wind power to help control rates by avoiding natural gas and electricity prices. Two, commenters practicing conservation are wondering why they are not seeing lower rates from reduced need for new or peaking plants or energy to serve them?

Q. What is Staff's response to the first concern listed above?

A. Actually, rates are lower than what they would be without wind and solar resources. In a world without wind and solar, the utility would have either needed on more high-cost wholesale power which may or may not be available or build other generation resources that are more costly to operate. Having wind and solar resources did not mean electric rates would not go up, just that they would not go up as much.

Q. What is Staff's response to the second concern listed above?

A. Again, without the conservation resources, just like wind and solar, rates would be even higher. Conservation allows utilities to avoid adding costly resources that would raise overall rates. We appreciate and understand the hardship that rate increases have on customers and the Commission has a long history on focusing on identifying the types of resources that should be added to reduce overall rates while ensuring the generation mix is also reliably serving the electricity needs of customers.

ISSUE 2. COB TRADING MARGIN REFINEMENT

Q. What are the California Oregon Border (COB) trading margins?

A. The MONET model assumes that all purchases and sale transactions are being made at the Mid-C market. However, PGE can transact at COB and monetize the price difference between Mid-C and COB by purchasing from COB when the spread is positive and selling to COB when the spread is negative. The COB margins adjustment was designed to capture this benefit in MONET.[33] It is a purely financial adjustment that does not impact the dispatch of the model. The COB Margin adjustment was originally proposed by Industrial Customers of Northwest Utilities (predecessor to AWEC) in UE 308.

Q. What is PGE's Proposal in this GRC?

A. The Company proposes to adjust the COB trading margin benefit calculated outboard of MONET to remove any benefit associated with COB transactions executed in advance of the final MONET contracts update. PGE testifies that the benefit associated with these transactions will be reflected in PGE's contracts and curves update; thus, customers will receive the full amount for COB trading margin forecast. This is framed as having no NVPC effect.[34]

Q. What support does PGE give for their proposal?

A. PGE explains that if PGE executed a deal before final MONET update, the benefits would be included in the test year forecast within the contract and

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[33] *See* PGE/300, Schwartz—Outama—Cristea/46, lines 7-10. Staff/200 is covering the Washington State Cap and Invest Program, in which the COB transactions are used as the basis for reducing sales volume eligible for incurring compliance obligation from the program.

[34] *See* PGE/300, Schwartz—Outama—Cristea/47, line 12.

curves updates. PGE notes that its COB trading margin model is not dynamic enough to ensure these updated contracts are accounted for in the model. Accordingly, benefits from the updated contract would be additive to the forecasted trading margin benefit, which could result in double counting.[35]

Q. Does Staff have any issues with their proposal?

A. No, Staff does not initially see any major issues with PGE's no-cost proposal. However, Staff does want to ensure that the Commission and parties are aware of the COB trading margin forecast value at the time of the Company's initial filing in order to address any concerns in testimony and to propose adjustments if it does not appear the contract updates are capturing all the benefits of trades at COB. Therefore, Staff recommends that PGE include a COB trading margin benefit value in the forecast provided in their initial filing. Staff does not want a situation in which a final number is provided with little ability to see the components.

Q. Does Staff have any additional issues to discuss related to the COB trading margins?

A. Yes. The following additional issues are discussed below: Monthly COB price spreads, benefit total, transmission costs, and the use of COB for the Washington Cap and Trade Carbon Obligations. While Staff is generally supportive in including the COB benefits value in their final November update, Staff is concerned about the calculation of that benefit number.

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35 *See* PGE/300, page 46, lines 11-20.

Q. What is Staff's understanding of the relationship between the Company's no cost proposal and the benefits value currently included in MONET?

A. To Staff's knowledge, even if the COB benefit is being used in the final contracts update, the Company would still be using the same method to calculate those benefits as they do now. This method of calculation has been scrutinized by Staff and Intervenors in the past. PGE has pointed to the PCAM as a way to validate their COB benefit value. However, Staff believes that the PCAM is just to ensure that the broader NVPC forecast are compared with actuals, this has not included a breakdown that included the actual COB value in previous years.

Q. Are there issues with the way that the monthly COB price spreads are included in MONET?

A. Yes. As a result of having transmission access to multiple markets, PGE is able to make hourly dispatch decisions to exploit arbitrage opportunities at COB. However, the financial adjustment limits monthly prices for COB by only two values for month, on and off peak. These limited prices for COB are then used to create the difference between COB and Mid-C. These prices/margins are multiplied by historical volume averages from the last three years to arrive at purchase and sale estimates for the test year. This fails to account for daily and hourly variation in price.

Similar to concerns raised in AWEC's opening testimony in UE 391, Staff is concerned that PGEs COB trading margin forecast method understates the margins because of this restriction in volumes and the restriction in price spread.

This is likely under forecasting the benefits of being able to transact at the COB market because the monthly COB averages mute the arbitrage benefit PGE receives from the Mid-C/COB price mismatch. Including the COB market directly in MONET, however, correcting for this may require significant modifications to the model logic, which may not be feasible during this proceeding.

Q. Has PGE responded to this concern before?

A. Yes. PGE explained that the current method for forecasting COB margins provides for a normalized and forecasted value that recognizes both seasonality and hourly variability by modeling the weighted price shape for COB by hour and day of the week and models hourly purchases or sales for each month of the year.[36] In addition, PGE also noted that AWEC's method is using trading volumes that are greater than PGE's firm rights on the California-Oregon Intertie (COI), and simulating a real-time hourly trading approach, when PGE primarily transacts at COB in the day-ahead market, which typically trades in on-peak and off-peak blocks.[37]

Q. How does Staff propose fixing the under forecast of benefits created by the monthly price spread?

[36] UE 391 PGE/300, Vhora—Outama—Batzler/38.
[37] UE 391 AWEC OT. See also Staff/102 PGE response to DR 337 (pdf).

A. As stated above in Issue 1, Staff supports moving to a new model that is capable of allowing transactions at multiple trading hubs.

Q. What benefits are included in this year's model?

A. Benefits included approximately $19 million in their initial forecast.[38] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** For comparison, the COB trading margin benefit forecast in the final 2022 NVPC was $12.9 million and was $22.5 million in the final 2023 NVPC forecast.[39] Staff wants to reiterate that it believes that all three of these numbers are likely under forecasted.

Q. How are the benefits calculated?

A. According to the Company's response to Staff DR 291, "MONET market sales represent the 2024 Mid-C wholesale sales forecast based on the MONET economic dispatch of PGE's portfolio and expected loads in 2024. COB transaction volumes are determined outboard of the MONET model and are based on three-year historical transactions at COB."[40] Essentially, the Company creates an hourly shape for COB prices using three years of historical data, applies this shape to the COB hourly forward price curve, calculates the hourly COB margin relative to the hourly Mid-C margin, and multiplies this forecasted margin by the historic sales when the margin is

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[38] See Staff/102, PGE response to DR 338 (pdf) for this initial forecast value. In its workpaper "#08_COB2019-21WeightedShape_12.30.22 Curves", PGE provided the historical transactions at the COB market and the associated prices for those transactions. PC Input tab on MONET, line 1591.

[39] See Staff/102, PGE Response to DR 339 (pdf) which provide these numbers aside from the CONF value.

[40] *See* Staff/102, PGE response to DR 291 Part A (pdf).

positive and historic COB purchases when the margin is negative. This current method of calculating the COB benefits has only been employed only since Docket UE 335.

Q. Why does Staff believe past values are under forecasted?

A. First, the COB monthly estimates that PGE uses in the calculation of hourly prices is simply limited to the on-and-off-peak value of the 12/30/2022 Curve.

Second, PGE's approach uses a monthly profile instead of an hourly one for both the price spreads (Mid-C to COB) and volumes. This is not representative of the actual sales and purchases made since it views the price spread on a monthly basis rather than an hourly basis.

Third, PGE's method restricts the volume of transactions by assuming that each month was either only a sale or only a purchase. However, PGE had both sales and purchases during that monthly period. Put in other words, PGE can choose to sell on the COB market during exceptionally high hourly Mid-C prices so using a monthly average understates benefits by mixing the high prices (that influence benefits) with low prices (that bring the average down).

Fourth, in PGE's weighted shape workpaper for MidC-COB 2024, they incorrectly have 25 values for the first day of 2024, which shifted all of their numbers down in the excel and could have resulted in a benefit estimate that is incorrect based on their own calculation steps.

Q. Does Staff have additional comments on the COB benefits?

A. Yes. Mid-C has been and is expected to continue to be above the national average and even that of the COB market at times. As a comparison, for 2023, so far, Mid-C has traded higher than NP 15 (the nearest electric trading hub to COB—aside from Malin) 60 percent of the time.[41] Because PGE is using the same method to calculate benefits in UE 416 as they did in UE 391 and UE 402, Staff assumes that there is still an underestimation of the benefits.

Q. How was this issue settled in UE 391?

A. The COB trading margin changes suggested by AWEC were not actually implemented in UE 391, as the Company, Staff, and Intervenors agreed to a black box settlement that reduced total NVPC by $6.25 million that was ultimately adopted by the Commission. Also included in that settlement was transmission resales, Colstrip Forced Outage Rate, Carty Forced Outage Rate, Beaver Forced Outage Rate, Day-Ahead Forecast Error Modeling, Avangrid Capacity Contract, Lydia 2.9, and EIM Grid Management Charges.[42]

Q. Provide some upfront context on Staff's recommendation.

A. In UE 391, AWEC's proposal raised benefits by 75 percent, which the Company claimed was too high due to transmission constraints.[43] For further support, PGE used their PCAM to show how they under recovered for power costs as a whole from 2017-2020 rather than providing a breakdown of actual benefits compared to forecasted benefits for COB only. Given the proposed

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41 Calculated using data from https://www.eia.gov/electricity/wholesale/#history using the weighted average and same trading days.
42 Order No. 21-380, page 4.
43 UE 391, PGE/300 Vhora—Outama—Batzler/43.

changes to PCAM in this year's GRC, including removing the deadband, there is a lower chance that a cost component, as minor as the Cob trading margins would be found imprudent or incorrect in their calculation of actuals, given that they are approved in their AUT filing and not included directly as a separate workpaper in the PCAM.

Unfortunately, in the short time we have during this proceeding, we are unable to clearly model COB Trading Margin benefits that incorporate hourly pricing and a transaction cap based on transmission constraints. As such, Staff proposes an adjustment that recognizes that the COB Trading Margin Benefit is clearly higher than what the Company models but will likely not butt up against any transmission constraints.

Q. What is Staff's recommendation?

A. Staff recommends that the benefits should be raised by 30 percent in this proceeding, for the purposes of the 2024 NVPC forecast to split the difference between PGE's under forecast and AWEC's over forecast. This adjustment of 30 percent when applied to their April update amounts to a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction in the total 2024 NVPC forecast. In light of the proposed changes to the PCAM, ensuring accuracy of costs is even more essential in UE 416 than it was in UE 391.

Q. What do you recommend that the Company do to model the COB Trading Margin in a future AUT proceeding?

A. I recommend that the Company find a way to model COB prices at an hourly level in a future TAM pricing, including any transmission constraints, whether this be through the existing MONET framework or through the adoption of a more sophisticated modeling software.

Q. Describe transmission costs related to COB transactions.

A. PGE includes approximately $3.4 million in transmission costs related to reduced forecast benefits from using their transmission rights to transact at the California-Oregon Border (COB) market.

Q. Describe the use of COB margins in the carbon calculations?

A. PGE also uses the COB transactions in their calculation of Mid-C volumes eligible for obligation under Washington Cap-and-Invest program.[44] According to the Company:

> PGE recognized that not all sales resulting from the MONET model will ultimately sink in Washington and create a carbon obligation for PGE. Therefore, we used the estimate of COB transaction volumes as a basis for reducing the sales volumes eligible for incurring a compliance obligation cost from the Washington Cap-and-Invest program. The months of November, December, and January reflect larger volumes at COB and therefore, PGE assumed that no market sales volumes are eligible for carbon compliance costs under the Washington Cap-and-Invest program.[45]

This is also discussed in Staff testimony (Ahmed/200).

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[44] Exhibit 33, Page 33.
[45] See Staff/102, PGE response to DR 291 Part C (pdf). *See also* PGE/300 Section III.C.

Q. Does Staff have an issue with the use of COB transaction volumes in the calculation of those eligible for carbon obligations?

A. Yes. Given that the margin forecast method understates the margins because it restricts the volume of COB transactions relative to the historical average, the amount of Mid-C volumes eligible for carbon obligations are likely to be overestimated. It is also worth noting, "PGE did not consider a different method to estimate the MWh volumes of market sales at Mid-C".[46] In addition, Staff is currently investigating whether a fair share of carbon obligations are shared between Washington State and Oregon.

Q. How are COB trading margins affected by participation in the EDAM?

A. It is clear that PGE has no binding requirements for participation in EDAM until 2025 however PGE does indicate that the design could impact the COB margins as CAISO would control the transmission rights available to the market by 10:00am.[47] It is worth noting, "PGE is in active discussions with the CAISO to better understand operational impacts of the EDAM on the COB, the details of these potential changes in flexibility are relatively unknown at this point."[48] EDAM is discussed further in Staff/400, Ahmed.

Q. Does this conclude your testimony?

A. Yes.

[46] *See* Staff/102, PGE response to DR 583 (pdf).
[47] *See* PGE/300, Schwartz—Outama—Cristea/50, lines 10-12.
[48] *See* Staff/102, PGE response DR 293 (pdf).

CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

May 24, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME: Julie Jent

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: I have a Bachelor of Science from Berea College in Political Science where I concentrated on economics and the regions of Eastern Europe and Southeastern Asia. I also hold a Masters of Integral Economic Development Policy specializing in the public sector and econometrics.

EXPERIENCE: I have been employed as a Junior Financial Analyst by the Oregon Public Utility Commission since June 2021 in the Telecommunications and Water division. I transitioned to the Rates, Safety and Utility Performance Division in July of 2022 within the Energy Costs section. Within this division, I currently perform a range of financial analysis duties related to natural gas, electric, and water utilities, with a focus on operations and maintenance. In addition, I assist with Purchased Gas Adjustments, Annual Power Cost filings, and General Rate Cases. Past rate cases include UG 435 and UE 399. I was previously employed as an adjunct professor of Econometrics at the Catholic University of American and as an Analyst in the Office of Management and Budget (OMB) within the Executive Office of the President (EOP), where I worked as part of a team on education funding. Prior to EOP, I was an Economic Consultant for the U.S. Conference of Catholic Bishops.

CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

May 24, 2023

April 10, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 371
Dated March 27, 2023

Request:

See the MONET Model File titled #2024GRC-B000n. Explain how changing a feature, such as enabling the Reliability Contingency Event Estimate on the input page, will flow through to the output pages at the end of the excel (PwrEnOut; PwrAEOut; PwrCsOut).

Response:

PGE objects to this request on the basis that it is vague. Subject to and without waiving this objection, PGE responds as follows:

Please see the MFRs submitted by PGE on February 15, 2023, Vol 10 – New Items and Enhancements. In these MFRs, PGE provides detailed information regarding each enhancement.

Certain items such as the RCE forecast, the Washington Cap and Invest costs, or the Winter Gas call option are calculated outboard and modeled in MONET simply as additional costs. These items will flow from the “PC Input” worksheet in the MONET model, to the “PGE Contracts” worksheet, and then to the output worksheets as distinct line items (i.e., “Q3 Capacity Planning Forecast Cost” for RCE, “Estimated Premium for Gas Option” for the winter gas call option, and “Estimated Washington Carbon Obligation” for Washington Cap and Invest costs). The toggles at the top of the “PC Input” worksheet enable or disable each enhancement item, which will determine whether the costs on the “PC Input” worksheet will be included in the final output reports listed in the request.

Other items that modify plant parameters or change fuel supply at our thermal plants will be included in the variable power cost to dispatch the thermal plants and not as a distinct line item on the output sheets.

April 10, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 378
Dated March 27, 2023

Request:

Explain how the MONET model is used in the MMA forecast.

Response:

For the 2024 MMA forecast, PGE uses the hourly diagnostic report output from a MONET model version that is used for internal budgeting purposes covering years 2023 through 2028. See PGE's response to CUB Data Request No. 029, Confidential Attachment 029-A for the MONET model. The hourly diagnostic report is used to estimate plant run hours over the period mentioned above. Based on the estimated run hours, PGE forecasts when a major maintenance is expected to be performed at our thermal plants that have MMAs.

See supporting confidential workpapers for PGE Exhibit 800, file "2024 GRC MMA Work Paper_Final for initial filing", worksheets "hrlydiagnosticenergy" and "Estimated Run Hours (2023-2028)".

April 10, 2023

To: Marc Hellman
Public Utility Commission of
Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 380
Dated March 27, 2023

Request:

Explain the purpose of each of the four different types of reports (Hourly Diagnostic Reports, DP Diagnostic Reports, Mid-C Ancillary Service Report, and Thermal Ancillary Service Report) that are available as an output to MONET.

Response:

Please see below an explanation for each of the reports referenced in this data request:

Hourly Diagnostic Reports: Generates the reports for hourly outputs for energy, average energy, and cost.

DP Diagnostic Reports: Generates the reports which show individual plant state outputs (plant states by hour, fuel prices, heat rates, etc).

Mid-C Ancillary Service Reports: Generates the report which shows how the model is allocating ancillary service requirements to Mid-C plants by hour.

Thermal Ancillary Service Reports: Generates the report which shows how the model is allocating ancillary service requirements to thermal plants by hour.

April 10, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 376
Dated March 27, 2023

Request:

Referring to Table 9 and the tab ‘2023.2.15_PwrEnOut’, please explain why PGE is conducting significant market sales and low market purchases, presumably at a time when there might be a greater requirement for more power in summer months (June to September) in rows 165 and 166.

a. Why is the model making these forecasts?

b. Without referring to the Monet model, please explain how and why this would be considered a good business practice.

Response:

a. See PGE Exhibit 300, pages 17, lines 13-22 and 21-23, lines 3-3 for a detailed discussion regarding the gap between how PGE dispatches its thermal plants in actual operations versus the economic dispatch in the MONET model and how this creates a disconnect between forecast market sales and purchases during summer months between the forecast and actual operations.

b. See response to part a., specifically PGE Exhibit 300, page 22, question: “Can or should PGE power operations follow the MONET dispatch logic during summer months?”

April 26, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 530
Dated April 12, 2023

Request:

Please discuss any experience the Company has with AURORA and other non-MONET forecasting software.

Response:

PGE objects to this request on the basis that it is vague and overly broad. Subject to and without waiving said objection PGE responds as follows:

PGE uses AURORA in conjunction with other models for the Integrated Resource Planning (IRP) and Clean Energy Plan (CEP) modeling. Please see modeling details in PGE's 2023 CEP/IRP, Appendix H.[1]

For IRP modeling, PGE also uses multiple Excel models, the Sequoia Simulation Model, and ROSE-E capacity model.
PGE Power Operations uses ABB/Hitachi's Portfolio Optimization to model the shorter-term (within the month) operational horizon.

[1] https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irpresources-materials,

April 26, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 531
Dated April 12, 2023

Request:

Has PGE considered moving away from using MONET to estimate power costs? If not, explain why.

Response:

PGE is currently considering options to enhance the modeling of the NVPC forecast, including new modeling software or methods other than MONET. However, PGE is in very early stages of assessing potential options and does not currently have details regarding alternatives to model the NVPC forecast.

March 30, 2023

To: Marc Hellman
Public Utility Commission of
Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 338
Dated March 16, 2023

Request:

Explain why there is no cost impact for the COB trading margin.

Response:

Staff's assertion that there is no cost impact for the COB trading margin is not correct. As provided in the COB trading margin file (see MFR location of the COB trading margin workpaper in PGE's response to OPUC Data Request No. 336), PGE includes approximately $19.0 million for COB trading margin forecast benefits in PGE's initial 2024 forecast (see tab "2024 Value"). Please note that the forecast COB trading margin benefit will change with each NVPC update, due to changes in forward market prices.

March 30, 2023

To: Marc Hellman
Public Utility Commission of
Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 337
Dated March 16, 2023

Request:

Refer to item 8a in Order No. 21-380. Please provide narrative discussion that addresses whether the Company implemented any of AWEC's suggestions regarding the COB Trading Margin since this order was filed.

Response:

Concerning item 8a, the Commission stated in Order No. 21-380:

> "AWEC argued that PGE's COB trading margin forecast method understates the margins because it restricts the volume of transactions relative to the historical average, and that it limits the price spread. PGE explained that the current method provides for a normalized and forecasted value that recognizes both seasonal and hourly variability. PGE also noted that AWEC's method is using trading volumes greater than PGE's firm rights, given they primarily transact in the day-ahead market."

PGE did not implement any of the forecast methodology changes proposed by AWEC in Docket No. UE 391. In UE 391, PGE did not agree with AWEC's proposed adjustments for reasons described in reply testimony (UE 391/PGE Exhibit 300, Section II.G) and joint testimony in support of the stipulation (UE 391/Stipulating Parties/100). Furthermore, the stipulation adopted through Commission Order No. 21-380, does not include any terms with respect to updating the COB trading margin methodology.

March 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 339
Dated March 16, 2023

Request:

By how much did the COB trading margin benefit the total NVPC for 2022 and is any benefit incorporated into the test year (2024)?

Response:

PGE objects to this request on the basis that it is vague and, to the extent that it is asking for actual COB trading margin benefits realized in 2022, it is unduly burdensome and requires new analysis. Without waiving this objection, PGE responds as follows:

PGE did not perform an analysis to calculate actual COB trading margin benefits realized in 2022.
Any such benefits are incorporated in PGE's final 2022 actual NVPC, which is subject to the 2022 PCAM. PGE does not include actual benefits realized from transactions at COB in the test year forecast for the COB trading margin benefit. PGE included a COB trading margin benefit forecast of approximately $12.9 million in the final 2022 NVPC forecast and approximately $22.5 million in the final 2023 NVPC forecast. For the initial 2024 COB trading margin forecast, see PGE's response to OPUC Data Request No. 338.

March 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 291
Dated March 14, 2023

Request:

In Tables 5 and 6 on Washington Cap and Invest, please explain:

a. How MONET market sales and COB Transactions are defined.
b. How total sales is less than COB sales.
c. Why there are no November, December and January carbon obligations.

Response:

a. MONET market sales represent the 2024 Mid-C wholesale sales forecast based on the MONET economic dispatch of PGE's portfolio and expected loads in 2024.
   California-Oregon Border (COB) transaction volumes are determined outboard of the MONET model and are based on three-year historical transactions at COB. The COB trading margin model assumes PGE can utilize our firm transmission rights at COB to transact between the Mid-C and COB markets and realize a trading margin.
b. Because the COB transaction volumes are calculated outboard of the MONET model and are based on actual historical transactions, there can be months when volumes at COB are larger than wholesale sale volumes that result from the economic dispatch of resources in MONET.
c. As described in PGE Exhibit 300, Section III.C, PGE recognized that not all sales resulting from the MONET model will ultimately sink in Washington and create a carbon obligation for PGE. Therefore, we used the estimate of COB transaction volumes as a basis for reducing the sales volumes eligible for incurring a compliance obligation cost from the Washington Cap-and-Invest program. The months of November, December, and January reflect larger volumes at COB and therefore, PGE assumed that no market sales volumes are eligible for carbon compliance costs under the Washington Cap-and-Invest program.

May 2, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 583
Dated April 18, 2023

Request:

What methods were considered for estimating the MWH volumes of sales at Mid C? For example, did PGE consider estimating the MWH sales as a function of past sales, or some other formulation? Please explain in detail.

Response:

As previously described in PGE Exhibit 300, Section II and PGE's response to OPUC Data Request No. 358, PGE's NVPC forecasting model, MONET, estimates market sales or purchases volumes priced at the Mid-C forward price to balance PGE's resource portfolio generation with expected retail load during every hour of the test year. PGE did not consider a different method to estimate MWh volumes of market sales at Mid-C.

March 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 293
Dated March 14, 2023

Request:

PGE states that there may be expected transmission constraints from participating in the EDAM and suggests the COB margins might be affected. Please explain in detail:

a. How COB margins will be affected.
b. What impact it will have on NVPC.
c. How it will affect consumers.
d. Possible plans PGE has to remedy possible constraints to meeting load.

Response:

a. PGE assumes that the referenced statement is the following: "However, this design could impact the California-Oregon Border (COB) transaction margins as CAISO would control the transmission rights available to the market by 10:00 a.m."[2] In this statement, PGE is referring to a potential reduction in operational flexibility in the market, not a "transmission constraint" which assumes congestion on a flowpath. As PGE is in active discussions with the CAISO to better understand operational impacts of the EDAM on the COB, the details of these potential changes in flexibility are relatively unknown at this point. Moreover, PGE notes that unlike the Western Energy Imbalance Market, EDAM is not an incremental market. Therefore, more time is needed to assess the potential benefits to PGE customers. PGE will continue to provide updates on the EDAM and impacts to PGE in the Quarterly Power Supply Update.

b. See part a.

c. See part a.

d. See part a.

[2] PGE Exhibit 300, page 50.

CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

May 24, 2023

PGE CONF Response to DR 169 Attachment A is only available in electronic format.

May 2, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 585_CONFIDENTIAL
Dated April 18, 2023

Request:

[BEGIN CONFIDENTIAL] [redacted].

[redacted]

a. [redacted]

[redacted]

[END CONFIDENTIAL]

Response:

a. [redacted]

[redacted]

[redacted]

b. See part a.

April 10, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 381
Dated March 27, 2023

Request:

Please provide:

a. [redacted]

b. [redacted]

Response:

a. [redacted]

b. [redacted]

Attachment 381-A is protected information subject to Protective Order No. 23-039.

PGE response to OPUC Data Request No. 381, part a.

a. [redacted]

2024 GRC – February 15, 2023 Initial Filing

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Source Documents

1. [redacted]

Monet Inputs

[redacted]

[redacted]

2024 GRC – February 15, 2023 Initial Filing

[redacted]

Source Documents

[redacted]

Monet Inputs

[redacted]

2024 AUT – February 15, 2023 Initial Filing

[redacted]

Source Documents

1. [redacted]

Monet Inputs

[redacted]

On the "PGE Contracts" worksheet:

- [redacted]

CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

May 24, 2023

[redacted]

[redacted]

CASE: UE 416
WITNESS: Ishraq Ahmed

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

May 24, 2013

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

A. My name is Dr. Ishraq Ahmed. I am a Senior Utility Analyst employed in the Energy Costs Section of the Rates, Safety, and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I present Staff's analysis regarding the net variable power cost (NVPC) impact associated with the Washington cap-and-invest program for PGE. I currently make no recommendations and no adjustments to the Company's revenue requirement. My and other Staff's recommendations may change based on further review and the testimonies offered by other parties.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits. My Witness Qualification Statement is in Exhibit Staff/201. The Non-Confidential Data Request (DR) Responses are in Exhibit Staff/202, the Confidential DR Responses are in Exhibit/Staff 203 and the Highly-Confidential DR responses are in Exhibit/Staff 204.

ISSUE 1. WASHINGTON CAP-AND-INVEST PROGRAM

Q. What is the Washington Cap-and-Invest Program?

A. The state of Washington passed the Climate Commitment Act (CCA) in 2021 aimed at reducing pollution and achieving greenhouse gas (GHG) limits set in Washington state law. The Washington Department of Ecology (Ecology) finalized the CCA regulations in October 2022 and the program was launched on January 1, 2023. Entities covered under the program started incurring emission compliance obligations on January 1, 2023.

Q. Is PGE a covered entity under the program?

A. Yes. Businesses are "covered entities" that will incur emission compliance obligations if they generate emissions that exceed 25,000 metric tons of CO2 equivalent per year (MTCO2e) in the State of Washington or import such emissions into the State. PGE testifies that it expects to be an importer of energy into the state of Washington at levels higher than the 25,000 MTCO2e and therefore needs to comply with the Cap-and-Invest Program requirements and incur carbon obligation that needs to be incorporated in the 2024 NVPC forecast.

Q. What is imported electricity?

A. Imported electricity is defined as electricity generated outside of Washington state with a final point of delivery within the State.[1]

Q. Why is PGE importing electricity into Washington?

1 PGE/300, Schwartz-Outama-Cristea/29.

A. PGE does most of its wholesale trading at the Mid-C market hub and makes wholesale sales to entities in the State of Washington.

Q. How does the CCA Cap-and-Invest Program work?

A. The Washington cap-and-invest program sets a limit or cap on overall carbon emissions in the state of Washington and requires covered entities to obtain compliance instruments equal to their covered greenhouse gas emissions (GHG) during a four-year compliance period. With some exceptions for emissions-heavy industries such as utilities serving retail customers, allowances are obtained through quarterly auctions or bought and sold on a secondary market. At the end of each compliance period, covered entities must submit compliance instruments equal to their covered GHG emissions for all years. These serve as evidence of emissions reduction by the amount required by the program for each of the four years.

Q. How are carbon allowance prices determined for entities that must purchase allowances?

A. While there is not sufficient information regarding the compliance cost yet, there are floor prices and ceiling prices for carbon allowances, and auctions for allowances determine the price settling between the floor price and the ceiling price.[2] The first auction for allowances took place in February 2023 with the cost of allowance set at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[3]

2 PGE/300, Schwartz-Outama-Cristea/31-32.

[redacted]

Q. Please explain how PGE's power costs will be impacted by the cap-and-invest program.

A. Every energy unit sale that PGE sources from production outside Washington and has a final point of delivery in Washington to sell to other utilities, will carry an associated carbon emission rate that needs to be covered under the program through carbon allowances or offset credits. PGE does not plan to invest in projects that generate offset credits and will use carbon allowances as the compliance instruments in the Cap and Invest program. [4]

Q. How did PGE determine the NVPC impact of the Cap and Invest program?

A. First, PGE uses MONET to determine the 2024 Mid-C wholesale sales forecast based on the MONET economic dispatch of PGE's portfolio and expected loads in 2024.

Second, PGE then recognizes that not all sales from the MONET model dispatch are to final points of delivery in Washington, and create a carbon obligation for PGE. PGE uses the California-Oregon Border (COB) transaction volumes determined outboard of the MONET model based on the prior three-year historical transactions at COB. The estimate of COB transaction volumes is used to reduce the MONET market sales volumes eligible for incurring a compliance obligation cost. [5]

Therefore the carbon obligation volumes can be expressed as:

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[4] See Staff/202, PGE Response to DR 290.

[5] See Staff/202, PGE Response to DR 291 and PGE/300, Schwartz – Outama – Cristea/33.

Washington Carbon Obligation (MWh) = (Total Market sales forecast from MONET) – (Total COB Volumes forecast)

Finally, using the carbon allowance floor price from the February 23rd auction and a blended portfolio emission rate of 0.437 MTCO2e/MWh [6] to the market sales forecast in MONET net of COB sales volumes, PGE obtains the estimate of the power cost impact of the Washington Cap-and-Invest program.

Q. What is the estimated NVPC impact associated with the program?

A. The Washington Cap-and-Invest program carbon obligation costs result in an estimated **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to PGE's NVPC.[8] The month-by-month carbon obligation cost is listed below in Table 1.

[BEGIN CONFIDENTIAL] [redacted]

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

Q. Why would PGE only incur carbon obligation for the months shown in Table 1?

A. PGE estimates the months of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to reflect larger volumes at COB, and therefore, PGE assumed that no market sales

7 [redacted]

8 [redacted]

9 [redacted]

volumes in those months (estimated from MONET) would be eligible for carbon compliance costs in Washington.[10] PGE's average load is highest in the winter months which causes most of the generation in MONET to serve customer loads instead of being sold in the market. [11]

Q. Is the carbon allowance price from the February auction the final price?

A. No. The Washington cap and invest carbon allowance price will be based on the results of four auctions to be held over the year in February, May, August, and December by the Department of Ecology.[12] The final NVPC forecast will however include the February 23rd auction price. [13]

Q. Will PGE incur carbon obligation costs separately for Washington-based resources and resources based outside Washington?

A. Although PGE generates power in Washington, it does so from the Tucannon River Wind Farm and purchases power from hydroelectric projects located in Washington. PGE presently has no thermal resources in Washington. Staff interprets that PGE will incur no carbon obligation cost for generating resources sited in Washington. [14]

PGE will sell energy in Washington generated from thermal resources located outside Washington. In instances where PGE would import electricity

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[10] See Staff/202, PGE Response to DR 291.
[11] See Staff/202, PGE Response to DR 619.
[12] https://apps.ecology.wa.gov/publications/documents/2302007.pdf (Washington Cap and Invest Program 2023 Summary of Expected Dates).
[13] PGE/300, Schwartz – Outama – Cristea / 32.
[14] See Staff/202, PGE Response to DR 289.

into Washington, the source would likely be unspecified, i.e., the source would not be known prior to the time of entry into the transaction and would come from PGE's portfolio. PGE's sales would carry the emission factor of 0.437 metric tons of CO2 equivalent per MWh.[15]

Q. Is PGE able to model total power sold and purchased in Washington broken down by thermal and non-thermal sources, with thermal sources subject to carbon obligation?

A. No. The MONET model does not identify unit-specific sales and purchases.[16]

Q. Can PGE track which plants will run and be used for exporting electricity to Washington?

A. As mentioned earlier, Staff had asked for confirmation on whether PGE would supply energy to Washington from thermal resources located outside Washington and whether they can identify which resources would be used. PGE stated that they would not know the source prior to time of entry into the transaction when electricity is imported into Washington and the source would come from PGE's portfolio. The sales would carry the emission factor of 0.437 metric tons of CO2 equivalent per MWh. [17] Staff at this point understands that PGE should at least have information on wholesale power sales made to each entity at the Mid-C hub even if they are not able to identify the specific resource at this time. [18]

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15 See Staff/202, PGE Response to DR 385. The information is taken from PGE's non-confidential response to DR 385. However, the attachment is subject to Protective Order No. 23-039.

16 Ibid.

17 Ibid.

18 Staff has issued a DR (DR 805) asking for this information on May 19th.

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Does Staff anticipate that PGE will update the forecast of Cap-and-Invest Program compliance costs to incorporate results of the auctions to be held later this year?

A. PGE indicated the carbon allowance price will be based on the results of four auctions to be held over the year.[19] PGE did not share specific details on how the price will be established in the Final Update, i.e., whether they will use the average price across all auctions, or whether they will use the price from the final auction. However, Staff anticipates that PGE will make appropriate updates to the final forecast to take into account auctions in May and August. Staff will likely file additional testimony on this issue in its Response Testimony.

Q. Does Staff have any concerns relating to PGE's forecast of the amount of energy that will be transmitted to Washington and subject to compliance obligations under the CCA?

A. Staff is investigating PGE's assumption of the amount of energy it will transmit to Washington in the test year. Staff is investigating how this assumption may be fine-tuned for the final forecast.

Q. Does Staff have recommendations related to the forecast of CCA compliance costs?

A. As noted above, Staff is continuing its investigation into the forecasted price of compliance and the forecast of energy subject to the compliance requirement.

[19] See Staff/204, PGE Response to DR 620. While DR 620 is Highly Confidential, the information is taken from PGE's non-confidential portion of the response.

Staff may have recommendations on these forecasts in their Response Testimony. Furthermore, the uncertainty of the forecasts suggests special treatment in the AUT and PCAM may be warranted for these costs in the early years of the CCA, particularly given that the CCA itself has been challenged in Federal District Court as violating the Dormant Commerce Clause.

Q. What challenge is being made to the CCA?

A. An independent power producer, Invenergy, Thermal, LLC, has filed a suit in the Federal Court in the District of Western Washington alleging the CCA violates the Dormant Clause and Equal Protection Clause of the Constitution. [20] Invenergy has asked the Court to issue an injunction against the Program on the ground it violates the Dormant Commerce Clause and Fourteenth Amendment. I am not an attorney, but it is my understanding that if Invenergy prevails, the Program may be discontinued, at least temporarily, or PGE may be entitled to free allowances for wholesale energy sales PGE makes to Washington utilities to serve the utilities' retail load. In either case, the cost of PGE's compliance with the CCA would decrease if utilities are required to transfer the appropriate amount of free allowances to the generators that presently incur carbon obligations.

Q. What special treatment is Staff considering?

A. Staff may recommend that CCA compliance costs not be subject to the PCAM deadband and sharing.

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[20] *Invenergy Thermal, LLC, and Grays Harbor Energy, LLC v. Laura Watson, Director of Washington Department of Ecology,* Case No. 3:22-cv-5967 (Western District of Washington).

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: ISHRAQ AHMED

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

May 24, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Dr. Ishraq Ahmed
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Costs Section
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	I have a Ph.D. in Economics from Southern Illinois University, Carbondale. I also hold a Master's degree in Economics from the University of Nottingham, UK, and a Bachelor's degree in Financial Economics with a minor in Mathematics from Centre College, KY.
EXPERIENCE:	I have been employed as a Senior Utility Analyst at the Oregon Public Utility Commission (PUC) since August 2022 in the Rates, Finance, and Audit Division where I am the Staff lead on gas utility rate issues. I have worked on annual Purchased Gas Adjustments, and Compliance filings and am currently working on Annual Power Cost filings and general rate cases UE 416 and UG 461. Before joining the PUC, I was an Assistant Professor of Economics at Black Hills State University and Dickinson College from 2017 through 2022. I have worked as a Graduate Research and Teaching Assistant during my Ph.D. training in conducting research with my Ph.D. supervisor and teaching graduate-level and undergraduate-level economics classes. I was previously employed as a Research Associate at the Institute of South Asian Studies with the National University of Singapore and before that, I served as an Economist with the Policy Research Institute coordinating a team of research assistants and working on research projects. I have additionally worked as a consultant with various multilateral organizations such as the International Labor Organization (ILO) and the World Bank.

CASE: UE 416
WITNESS: Ishraq Ahmed

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Non-Confidential Data Responses in Support Of Opening Testimony

May 24, 2023

March 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 289
Dated March 14, 2023

Request:

From PGE/300, Schwartz–Outama–Cristea/29, which states, "We expect PGE will be an importer of energy in the state of Washington..."

(a) Does PGE expect to be a net importer of power in Washington?
(b) If PGE is a net importer of power in Washington, what is the fraction of total power imported in Washington?
(c) Will PGE generate power in Washington?

Response:

Schwartz-Outama-Cristea/28-29 describes an expectation that PGE will report electricity imports at levels resulting in reported emission levels greater than 25,000 metric tons of CO2 equivalent and therefore be identified as a covered entity subject to the Washington Cap and Invest program requirements.

As an electric power entity, PGE must report 2022 emissions to the Washington Department of Ecology by June 1, 2023. Therefore, PGE's review of 2022 electricity imports, exports and resulting emissions is ongoing and not yet complete.

a. Yes. PGE's expectation continues to be that 2022 reporting data will show PGE has qualifying electricity imports, even after accounting for "netting". WA reporting rules (WAC 173-441 (2)(g)(iv)) do allow for a "netting" of unspecified electricity imports and exports by the same entity within the same hour. However, unspecified electricity exports are limited to a source of electricity that is not a specified source at the time of entry into the transaction to procure electricity (WAC 173-441 (d)(n)). If the reporting entity has
(1) an ownership share in the facility or (2) a written power contract to procure electricity generated by that facility PGE anticipates that the resource will qualify as a specified source of electricity (WAC 173-441 (2)(m)).

b. PGE has not yet finalized 2022 reporting. PGE will supplement its response to this data request after it reports 2022 emissions to the Washington Department of Ecology. Presently, PGE is required to submit its report by June 1, 2023.

c. Yes. PGE owns the Tucannon River Wind Farm located in Washington. PGE also purchases power from hydroelectric projects located in Washington. See MFRs, Vol 4 - Hydro\Large-Scale Contracts for additional detail.

March 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 290
Dated March 14, 2023

Request:

Regarding Washington's Cap and Invest: PGE does not have offset credits at this time. Does it plan to invest in projects that generate these and use them as alternative to the carbon allowance?

Response:

Presently, PGE is not evaluating investments in projects that generate offset credits.

PGE notes that allowances remain the predominant compliance instrument in the Washington Cap and Invest program. In the first compliance period (2023 – 2026), the WA Department of Ecology will allow the use of offset credits for up to 8% of cover emissions. See WAC 173-446-600 for details, specifically WAC 173-446-600 (7) states:

> (7) A portion of each covered entity's or opt-in entity's compliance obligation may be met by offset credits placed in the covered entity's or opt-in entity's compliance account. Each offset credit is worth one metric ton of carbon dioxide equivalent.
>
> (d) For the first compliance period (January 1, 2023, through December 31, 2026):
>
> (i) No more than five percent of a covered entity's or opt-in entity's compliance obligation may be satisfied by offset credits from projects not located on federally recognized tribal land.
>
> (ii) In addition to, but separate from the limit in (a)(i) of this subsection, a covered entity or opt-in entity may satisfy up to three percent of its compliance obligation using offset credits generated from offset projects on federally recognized tribal land.
>
> (iii) Unless ecology has linked with an external GHG trading system, all offset credits must provide direct environmental benefits to Washington state.
>
> (iv) If ecology has linked with an external GHG trading system, at least 50 percent of any offset credits used by a covered entity or opt-in entity for compliance must be sourced from offset projects that provide direct environmental benefits in Washington state. The remaining amount must be located in a jurisdiction with which ecology has linked.

March 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 291
Dated March 14, 2023

Request:

In Tables 5 and 6 on Washington Cap and Invest, please explain:

(e) How MONET market sales and COB Transactions are defined.
(f) How total sales is less than COB sales.
(g) Why there are no November, December and January carbon obligations.

Response:

c. MONET market sales represent the 2024 Mid-C wholesale sales forecast based on the MONET economic dispatch of PGE’s portfolio and expected loads in 2024. California-Oregon Border (COB) transaction volumes are determined outboard of the MONET model and are based on three-year historical transactions at COB. The COB trading margin model assumes PGE can utilize our firm transmission rights at COB to transact between the Mid-C and COB markets and realize a trading margin.
d. Because the COB transaction volumes are calculated outboard of the MONET model and are based on actual historical transactions, there can be months when volumes at COB are larger than wholesale sale volumes that result from the economic dispatch of resources in MONET.
e. As described in PGE Exhibit 300, Section III.C, PGE recognized that not all sales resulting from the MONET model will ultimately sink in Washington and create a carbon obligation for PGE. Therefore, we used the estimate of COB transaction volumes as a basis for reducing the sales volumes eligible for incurring a compliance obligation cost from the Washington Cap-and-Invest program. The months of November, December, and January reflect larger volumes at COB and therefore, PGE assumed that no market sales volumes are eligible for carbon compliance costs under the Washington Cap-and-Invest program.

April 10, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 385
Dated March 27, 2023

Request:

Please refer to Schwartz–Outama–Cristea/29-30: "Therefore, beginning January 1st, PGE must anticipate incurring a carbon obligation for many of the trades that PGE transacts under the standard Mid-C trading product, because the energy supply supporting PGE's trading activity is often the economic dispatch of PGE's thermal resources that are not located in the state of Washington (i.e., PGE would anticipate being the responsible importer)."

i. Please confirm whether it is correct to interpret the phrase "many of the trades that PGE transacts…" as saying that not all trades at Mid-C will incur a carbon obligation. If so, please provide a narrative description and workbook demonstrating how PGE models the proportion of trades that will incur carbon obligations. If not, please provide an alternative correct interpretation.

(h) Please provide a monthly forecast of the total power sold by PGE in WA that will be transacted at the Mid-C trading hub broken down by thermal and non-thermal resources.

(i) Please provide a monthly forecast of the total power sold by PGE to a non-WA buyer that will be transacted at the Mid-C trading hub broken down by thermal and non- thermal resources. Please discuss whether the thermal resources would be subject to a carbon obligation.

(j) Please provide a monthly forecast of the total power bought by PGE from a generator in WA that will be transacted at the Mid-C trading hub broken down by thermal and non-thermal resources. Confirm whether the price PGE would payfor this energy is directly or indirectly affected by any carbon obligations.

(k) From the PGE's statement above, Staff is interpreting that PGE will supply energy to WA from thermal resources located outside WA. Please confirm whether the interpretation is correct and identify which thermal resources PGE will use to supply energy to Washington.

(l) Please provide the following figures by month in the following format, with cell references and formulae intact for the test period:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mid-C MWh eligible for Carbon Obligation (from resources in WA)												
Mid-C MWh eligible for Carbon Obligation (from resources outside WA)												
Total Market Sales (WA) $												
Total Market Sales (outside WA) $												
Total Market Sales (WA) MWh												
Total Market Sales (outside WA) MWh												
WA Carbon Obligation cost (generated from WA resources) $												
WA Carbon Obligation cost (generated from resources outside WA) $												
Total WA Carbon Obligation cost $												

Response:

i. Correct. Since the MONET model prices all sales at the Mid-C price curve there is an implied model assumption that transactions are executed under the standard Mid-C trading product, which is the Mid-C physical product listed on the Intercontinental Exchange (i.e., ICE). Currently, parties selling the standard product assume a carbon obligation risk, because the standard product does not preclude delivery at a Washington sink point. Therefore, the price curve used in MONET presently includes price uplift for carbon risk and this price is applied to all sales and purchases in the MONET model.

While priced at the Mid-C price curve, PGE noted in PGE Exhibit 300 at 33 that not all sales resulting from the MONET model dispatch will ultimately sink in Washington and create a carbon obligation for PGE. PGE used its estimate of COB transactions as a basis for reducing the MONET model sales volume eligible for incurring a compliance obligation. The workbook demonstration is in the MFRs, Vol 10 - New Items and Enhancements\Step 00n - Washington Cap and Invest, file “#WA Cap and Trade”.

a. The MONET model does not identify unit-specific sales. However, in the forecast of Mid- C MWh eligible for carbon obligation, PGE assigns an unspecified emission factor of 0.437 metric tons of CO_2 equivalent per MWh **to all eligible MWhs**.

A breakdown of hourly dispatch and portfolio sales can be found in PGE’s MFRs filed on February 15, 2023, folder “ToPUC”, file “#2024GRC-B000n-HourlyDiagnostics”, tab “hrlydiagnosticenergy”.

b. A forecast for power sold by PGE to a non-WA buyer transacted at Mid-C would be 0 MWh in each month, because the modeled transactions in the MONET model are first priced at the standard Mid-C product. See PGE's response in part (i.). In practice, if PGE sells a non-standard Mid-C product (i.e., parties agree that the power will not sink in Washington) the sale will not incur a carbon obligation, including sales associated with emitting sources such as thermal resources.

c. The MONET model does not identify unit-specific purchases. See the description of how the MONET model economically dispatches PGE's portfolio in PGE Exhibit 300, Section II. As described in PGE Exhibit 300, given thermal output, expected hydro and wind generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with hypothetical market purchases (or sales) priced at the forward market price curve. Market purchase volumes and costs are provided in the MONET model output worksheets, "PwrEnOut", "PwrAEOut", and "PwrCsOut", under row "Market Purchases". See PGE's response in part (i.). The price curve used in MONET presently includes price uplift for carbon risk and this price is applied to all sales and purchases in the MONET model.

d. Yes. In PGE Exhibit 300 at 30, PGE is describing the fact that PGE's opportunity to sell power can be a function of PGE's thermal resources being economical for dispatch, which then results in PGE's total supply of economical dispatch being greater than its load obligation. Our examples in PGE Exhibit 300 at 30 focus on the summer months when the MONET model monetizes generation length from our peaking resources through wholesale market sales. In instances where PGE would need to import electricity into Washington to meet these modeled sales levels the source would likely be unspecified, because the source would not be known prior to time of entry into the transaction (i.e., the source would come from PGE's portfolio). In these instances, PGE's sales would carry the unspecified emission factor of 0.437 metric tons of CO_2 equivalent per MWh.

e. PGE objects to this request on the basis that it is vague. Subject to and without waiving this objection, PGE responds as follows:

   Confidential Attachment 385-A uses the MONET model results from its initial filing as the basis for populating the table provided by Staff.

   Mid-C MWh eligible for Carbon Obligation (from resources in WA): Values reported are MWhs from resources located in WA when the resource volume is produced in the same hour that a sale is made in MONET.

   Mid-C MWh eligible for Carbon Obligation (from resources outside WA): Values reported are MWhs from non-WA resources when the volume from WA resources is not large enough to meet the hourly volume sold in MONET.

Total Market Sales (WA) $: This is all MONET sales reported in the MFR. Since MONET prices all sales at Mid-C, the dollar amount reported is for all sales.

Total Market Sales (outside WA) $: This value is 0. MONET prices sales as if all were sold at Mid-C.

Total Market Sales (WA) MWh: This is all MONET sales reported in MFR. Since MONET prices all sales at Mid-C, the MWh amount reported is for all sales.

Total Market Sales (outside WA) MWh: This value is 0. MONET prices sales as if all were sold at Mid-C.

WA Carbon Obligation cost (generated from WA resources) $: This value is 0 if the resources located in WA (i.e., hydro and wind resources) are assigned an emission factor of 0 MTCO2e/MWh.

WA Carbon Obligation cost (generated from resources outside WA) $: This value is the result of MWh from resources outside WA multiplied by an unspecified emission factor (0.437 MTCO2e/MWh) and an allowance price of $48.50 per MTCO2e.

Attachment 385-A is protected information subject to Protective Order No. 23-039.

April 10, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 386
Dated March 27, 2023

Request:

Please confirm and clarify whether carbon obligation costs from the Cap and Invest program applies to all sources of emissions associated with the production and consumption of energy, regardless of whether energy units were produced inside or outside of Washington.

Response:

PGE objects to this request on the basis that it is overly broad. Subject to and without waiving this objection, PGE responds as follows:

Washington Administrative Code (WAC) 173-446-040 defines covered emissions under the Washington Cap-and-Invest Program. In general, electricity generation in the state of Washington and electricity imports into the state of Washington are covered emissions.

May 8, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 619
Dated April 24, 2023

Request:

In response to DR 291 c), PGE stated: "The months of November, December, and January reflect larger volumes at COB and therefore, PGE assumed that no market sales volumes are eligible for carbon compliance costs under the Washington Cap-and-Invest program." Why would these months reflect larger volumes at COB? Please explain.

Response:

As previously described in PGE's response to OPUC Data Request No. 291, the COB trading margin method is an outboard calculation that is not tied in any way to the MONET model economic dispatch. The estimated COB transaction volumes are based on actual volumes from the most recent three full years and transaction volumes in the months of November through January are not materially different than other months within the COB trading margin method.

However, COB transaction volumes are larger than MONET-estimated market sales from November through January because PGE's average load is highest in winter months, which causes most of the generation in MONET to serve customer loads instead of being sold in the market. In summer, forecast energy prices are typically much higher relative to gas prices – and so MONET dispatches generation at a higher level relative to loads which generates a surplus to be sold in the market. Shoulder months have surplus generation due to lower loads.

CASE: UE 416
WITNESS: Ishraq Ahmed

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Confidential Data Responses in Support Of Opening Testimony

May 24, 2023

[redacted]

CASE: UE 416
WITNESS: Ishraq Ahmed

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Highly-Confidential Data Responses in Support Of Opening Testimony

May 24, 2023

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CASE: UE 416
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

May 24, 2023

Q. Please state your names, occupations, and business address.

A. My name is Curtis Dlouhy. I am an economist employed in the Strategy and Integration 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 backgrounds and expertise.

A. My witness qualification statements can be found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's testimony on the following net variable power cost issues:

- Gas Resale and Storage Modeling
- 2024 Gas Physical Call Option
- Capacity Planning

Q. Did you prepare any exhibits for this testimony?

A. Yes. I prepared two exhibits:

- Exhibit Staff/301 – Witness Qualification
- Exhibit Staff/302 – Data Requests used in support of testimony

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. GAS RESALE, STORAGE, AND OPTIMIZATION MODEL UPDATES

Q. What is PGE's Gas Resale, Storage, an Optimization Model?

A. In the 2021 AUT, PGE proposed a method to capture potential natural gas storage optimization benefits that could be realized based on North Mist storage injection and withdrawal cycles relative to forward gas prices at the Sumas and Rockies markets and the economic dispatch of the Port Westward/Beaver complex. To determine a potential gas storage optimization monetary benefit, PGE evaluates a weighted average cost of gas (WACOG) in storage based on inventory levels and market prices, and planned gas storage injections during months of lower forecasted natural gas market prices. PGE added further refinements and enhancements to the forecasted dispatch costs for the Port Westward/Beaver complex based on an economic optimization of the available fuel supply at the complex to meet expected fuel demand and prioritize plant heat rate efficiency. Additionally, the gas modeling informs run hour constraints for Beaver's dispatch based on the fuel availability at 13 the PW/Beaver Complex.[1]

Q. Please describe the Company's proposal to update its gas resale, storage, and optimization model?

A. The Company has proposed a series of changes to its gas storage, resale, and optimization models. The changes are as follows:

[1] PGE/300, Schwartz – Outama – Cristea / 35.

1. An adjustment to the North Mist gas supply model logic to prioritize supplying Port Westward 2 and Beaver during high load hours. This reduces the forecasted NVPC by $4.3 million.
2. An update to the delivered gas availability that assumes no delivered gas will be available for March and November, which the Company states is required to be consistent with operational constraints. This increases the forecasted NVPC by $11.7 million.
3. A reduction to the Port Westward 2 renewable integration fuel hold by 5,000 dekatherms per day. This reduces NVPC by $1.9 million.
4. An update the MONET model logic to dispatch Beaver Unit 8 only when there is sufficient fuel left over from Port Westward and Beaver Units 1-7. This increases NVPC by $6.3 million.

Q. Regarding the first change, how did the Company's MONET model choose to supply Port Westward 2 and Beaver from North Mist in past NVPC forecasts?

A. Prior to the Company's proposed change, the Company's MONET model would choose to fuel three plants – Port Westward, Port Westward 2, and Beaver – by supplying whichever plant has the lowest marginal cost on the dispatch curve and moving to the next plant once the most efficient available plant is at full capacity. The Company prioritizes the fuel choice based on cost, with the options being pooled gas, stored gas, delivered gas, or gas from various trading hubs. The fuel choices and dispatch order both vary by month but do not appear to have any price shaping. In effect, this means that Port

Westward is essentially always running as a baseload plant while the other two plants adjust to capacity in MONET.

This setup meant that MONET was not able to distinguish between high load hours (HLHs) and low load hours (LLHs) when choosing how to supply Port Westward 2 and Beaver with stored gas. As explained in the Company's opening testimony, the effect of this was that MONET would indiscriminately supply gas to these two plants during LLHs, leaving less stored gas available during HLHs where open market electricity is relatively more expensive.[2]

Q. What has the Company done in its MONET model to solve this problem?

A. The Company adds an ad hoc adjustment to essentially "trick" MONET into thinking that it has the choice to send stored gas to five plants instead of the three plants that can receive stored gas. They do this by making two copies of Port Westward 2 and Beaver in MONET that operate at different times of the day. Between these two pairs of plants with identical operating data, one is tagged as a plant that can only be ran during HLHs while the other can only be ran during LLHs. When prioritizing fueling, the Company sets the two HLH versions of the plant to be prioritized over the two LLH versions. In effect, this means that stored gas will be used to fuel generators during HLHs over LLHs.

Q. Do you agree with this modeling change?

A. Yes, in part. I support the Company's change to prioritize fueling during HLHs over LLHs and believe this to be an improvement. However, I have concerns

[2] PGE/300, Schwarz – Outama – Cristea/36.

over the simplicity of MONET’s overall treatment of gas dispatch and question why the Company proposed another ad hoc adjustment to offset the simplicity of the model in lieu of switching to a more sophisticated modeling software.

Q. What concerns do you have with the simplicity of the MONET model?

A. I am concerned that the simplicity of the MONET model requires ad hoc adjustments to address MONET’s lack of any gas price shaping. In its current form even with the distinction between HLHs and LLHs, MONET only has a uniform monthly gas price that the fuel prioritization is based on. This monthly average does not capture the nuance of any sort of weekly, daily, or hourly differences in the open market price or gas transmission constraints that can occur during an exceptionally cold sequence of days or another market anomaly. With any sort of daily or hourly price shaping, the proposed change would likely not even need to be necessary.

Q. Are there other ways to forecast NVPC that avoid the issues you have identified with MONET?

A. While no model is perfect, there are plenty other modelling software options that look at fuel price at a more granular level. One such option is AURORA, which is utilized by PacifiCorp in its NVPC proceedings to forecast NVPC. I recommend that the Company explore how to integrate more granular prioritization of gas fueling sources in MONET or perhaps even switch to a different model, such as AURORA.

Q. Do you have any other concerns with the Company's modeling choice in this proceeding?

A. Yes. As I mentioned above, the Company only applied the HLH and LLH distinction to Port Westward 2 and Beaver because Port Westward operates as a baseload power plant. This choice to not make the distinction between HLH and LL to Port Westward changes makes sense in the context of having a uniform natural gas price at the monthly level because a LLH baseload plant would likely still need to be fueled before either of the two other plant options. However, I am concerned that the uniform gas price over-forecasts the cost to supply Port Westward.

Q. How could a uniform monthly price over-forecast the cost to supply a baseload plant?

A. The uniform monthly prices in the Company's MONET model mean that the prioritization of fuel sources stays constant throughout every hour of the month. However in reality, one would expect that there could be fluctuations in the costs between these fuel sources that changes the way they should be utilized. As an example, suppose that the Company has a set amount of stored gas that can be used in a month. If the Company's MONET model were able to model hourly gas shapes, this set quantity of stored gas could be dispatched to hours with higher gas market prices while hours with lower gas market prices could rely more heavily on the other sources of gas. Assuming that the current monthly gas price forecast is representative of hourly prices, optimizing stored gas in this way would in effect lower the NVPC estimate by having MONET avoid natural gas markets when the prices are highest.

Q. Do you have any adjustments to the Company's first proposed change for the 2024 NVPC forecast?

A. No. However, I reiterate that I recommend that the Company explore implementing an hourly gas shape in MONET or switch to a more nuanced modeling software, such as AURORA.

Q. Please describe the second change PGE proposes for its gas modeling?

A. The second change is an update to the delivered gas availability that assumes no delivered gas will be available for March and November. In past rate cases, the Company assumed that there is zero delivered gas in the months of December, January, and February.[3] This change extends that period for an additional two months.

Q. Why does the Company propose to make MONET assume that there will be no delivered gas for the months of November and March?

A. The Company states this change is necessary to make MONET consistent with operational constraints. When proposing this change, the Company states that it has to compete with natural gas being used for space heating.[4] Prior to this proposed change, the Company had already assumed that there is zero delivered gas in the months in December, January, and February.[5] Outside of

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3 PGE/300, Schwarz – Outama – Cristea/37.
4 PGE/300, Schwarz – Outama – Cristea/37.
5 PGE/300, Schwarz – Outama – Cristea/39.

the zero gas months, the Company also states that it relies on 47,921 dth/day of non-firm delivered gas throughout the year outside of the winter months.

Q. Does the Company say anything about its use of non-firm delivered gas during these months in its testimony?

A. No. The Company states that it considers no gas will be available during these colder months for planning purposes.

Q. Is this an appropriate way to forecast NVPC?

A. No. While it may be true that there will be many days with no delivered gas during these colder months and that the Company cannot rely on firm deliveries, there may be days in which the Company secures a non-firm delivery. The NVPC forecast is not a binding planning docket, but rather a forecast of expected costs. Assuming zero delivered gas for these two months when there is some expectation that a non-firm delivery will be available unnecessarily raises the expected cost, particularly in shoulder months such as November and March where temperatures are not necessarily uniformly cold.

Q. What have you done to try to quantify the cost impacts of fully excluding delivered gas during these months?

A. In Staff DR 433, I ask the Company to provide both the average price paid and monthly quantity of delivered gas for every month from 2010 to 2022.

Q. What did you learn from the Company's response to Staff DR 433?

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[redacted] **[END HIGHLY CONFIDENTIAL]** Given the modeling constraints of MONET that I discuss above, I recommend an adjustment be made to the total NVPC to reflect that some amount of delivered gas is available during these months. To calculate this adjustment, I re-run MONET assuming that the delivered gas for the months of November through March reflect the three-year rolling average of the daily delivered gas for these months. Based on the Company's response to Staff DR 433, this amount is **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**.

Q. What is your adjustment to the Company's second proposed change for the 2024 NVPC forecast after re-running MONET?

A. Based on PGE's April 1 MONET update, adding in the amount of delivered gas described above results in a decrease to NVPC of $325 thousand. I recommend making a downward adjustment of $325 thousand.

Q. Please describe the third change PGE proposes for its gas modeling?

A. The Company proposes a change to its gas modeling, which reduces the Port Westward 2 fuel hold for renewable integration. This is a change from past rate cases where the Company derated North Mist gas delivery to Port Westward 2 by 5,000 dth/day for ancillary services.

Q. Why does the Company reduce the Port Westward 2 fuel hold for renewable integration?

A. The Company states that there is no longer a need to hold as much fuel due to changes in its ancillary services dispatch and proposes to remove the 5,000 dth/day hold, which results in a decrease in forecasted NVPC by $1.9 million.[6]

Q. Do you have any adjustments to PGE's proposed change?

A. Not at this time.

Q. Regarding the Company's fourth proposed change to its gas modeling, why does the Company separately model Beaver Unit 8 from Beaver Units 1-7?

A. The Company states that this is done because Beaver Unit 8 is not interconnected with the North Mist gas storage facility, unlike Beaver Units 1-7 and Port Westward. Despite this, the entire Beaver facility was dispatched together in MONET in previous years.[7] While the Company states that this did not matter much due to Beaver Unit 8 having a higher heat rate than the market, market conditions have changed sufficiently that Beaver Unit 8 would dispatch in MONET without any consideration of fuel availability after Port Westward and Beaver Units 1-7 dispatched.[8] Making this change results in an increase to forecasted NVPC of approximately $6.3 million.

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6 PGE/300, Schwarz – Outama – Cristea/39.
7 Id.
8 PGE/300, Schwarz – Outama – Cristea/39.

Q. What have you done to investigate this issue?

A. I began by investigating MONET to see if Beaver Unit 8 was modeled the same way that the Company describes in its testimony. The Company's model logic appears to reflect the reasoning that was provided in testimony. I then read the white paper regarding Beaver that PGE provided with its minimum filing requirements to see if Beaver Unit 8 does indeed function differently than the other seven units. Based on my reading of the white paper, this appears to be the case.

Q. Do you have any recommendations regarding the Company's changes to Beaver Unit 8?

A. Not at this time.

ISSUE 2. 2024 GAS PHYSICAL CALL OPTION

Q. Please summarize the Company's physical gas call option contract.

A. The Company proposes to include a gas call option contract in the 2024 NVPC forecast as a hedge against large price spikes during the 2024 winter months. The Company states that their operational experience leads them to expect that high natural gas prices and price volatility in the winter months, which was present in the last two years, will continue.[9]

Q. What are the terms of this contract?

A. The contract has not been executed, but the Company says that it intends to provide MONET with the most finalized terms once the contract is finalized. The Company plans to have the physical gas call option active for the months of January, February, and December of 2024. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What is the total added cost to NVPC of the physical gas call option and how is the added cost integrated into MONET?

A. The additional cost of this call option is approximately $2.2 million. This $2.2 million amount to hold the call option is simply the result of premium price times quantity over the period that the contract is active. I have inspected the MONET code and confirmed that this is indeed the case.

[9] PGE/300, Schwarz – Outama – Cristea/45.

Q. Do you take issue with the use of a physical call option to mitigate higher and more volatile natural gas prices?

A. No. I take no issue with the Company's conclusion that the natural gas prices are expected to be higher and more volatile based on the experiences of the last two years. However, I do not agree with the Company's choice to model the NVPC effect of this call option as purely the contract costs without considering any offsetting NVPC benefits in MONET.

Q. Given that the nature of the physical call option is used to mitigate the NVPC effects of gas market price spikes in the winter months, why is there not an off-setting effect on the NVPC in MONET?

A. As I have discussed previously, MONET only considers a monthly average gas price when setting the Company's fueling priorities and natural gas plant dispatch. The physical call option is intended to insulate the Company against the large volatility that it claims it expects to be the norm moving forward in natural gas markets. The Company's current MONET framework does not have the capability to forecast the NVPC effects of having to transact without a physical call option nor the potential customer benefits of having a call option.

Q. How large do you believe the offsetting NVPC benefit to be of the physical gas call option?

A. If the execution of a physical gas call option is a prudent business move based on the Company's expectations of the price and volatility of natural prices in 2024, then the NVPC benefit of the physical gas call options should be at least as large as the cost of the call option on a risk-adjusted basis.

Q. If pursuing the gas call option is a prudent business move and there are no large price spikes, is there a risk that the Company will be unable to recover costs even though it acted prudently?

A. No. The Company still has an active PCAM that allows it recover costs that can be attributed to abnormal variances in power costs. If indeed the Company does prudent hedging against risk that qualifies for PCAM recovery, then it should still be able to recover any abnormally large costs retroactively.

Q. Based on the lack of modeling nuance, how do you recommend that the Company treat the cost of the physical call option in the 2024 NVPC forecast?

A. For the purposes of forecasting power costs, I recommend that the cost of the physical gas call option be removed from the 2024 NVPC forecast. This results in a downward adjustment to the 2024 NVPC of $2.2 million based on the proxy contract that the Company has included. I would like to reiterate that I am not objecting to the Company's decision to seek out a physical gas call option, but rather that I do not believe that including the $2.2 million associated with its inclusion in MONET accurately forecasts the NVPC effects of holding the call option.

Moving forward, the inability to quantify possible benefits of a physical gas call option is yet another reason that I recommend that the Company integrate a gas price shape or entirely switch to a new software to model NVPC in future years.

ISSUE 3. CAPACITY PLANNING

Q. Please summarize the Company's proposal regarding capacity planning in its NVPC forecast.

A. The Company has made two overall changes to its NVPC forecast to integrate capacity planning. The first change is to include a proxy Peak-for-Super Peak physical hedge contract effective during the third quarter in the 2024 NVPC forecast.[10] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[11] The second change is to incorporate a forecast of the annual cost associated with holding additional capacity reserves in the Day-Ahead planning window during Reliability Contingency Events (RCE).[12] The newly implemented RCE forecast results in a $3.9 million increase to the NVPC forecast as proposed by PGE.

Q. Why does the Company believe that changes need to be implemented in MONET to address capacity planning?

A. As described in the Company's opening testimony, the capacity planning landscape has changed dramatically to address capacity shortfalls that have become increasingly common in the Western Electricity Coordinating Council (WECC) footprint. PGE cites the increased number of Energy Emergency Events (EEAs) declared by WECC in the last 15 years along with the increasing presences of variable energy resources due to decarbonization

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10 PGE/300, Schwartz – Outama – Cristea/23.
11 PGE/300, Schwartz – Outama – Cristea/28.
12 Id.

legislation as evidence of its assertion.[13,14] The Company further states that MONET's logic is not built to provide an accurate forecast of the extreme price volatility associated with EEAs or other capacity shortage events.[15]

Q. Do you agree with the Company's characterization that the capacity planning landscape has substantially changed in a way that impacts NVPC?

A. Yes, at least for the near future. As the Company described in its opening testimony, the energy landscape has changed drastically as renewables begin to penetrate the system in a non-trivial way due to both decarbonization legislation and resource economics. While renewables often have a near-zero marginal cost that provides many energy cost benefits to customers, there are non-trivial costs to provide reliability to the system in higher-than-average demand periods or stretches where renewable generation is low. Although some of these costs are captured and can be quantified through renewable integration, these costs don't fully address the sharp spikes in wholesale prices associated with capacity shortage events.

Q. What evidence do you have that capacity shortage events contribute to abnormal costs that are not easily modeled by MONET?

A. I analyzed the average Mid-C hourly spot price during periods that were identified as RCEs and compared those prices to equivalent hours in the same

13 PGE/300, Schwartz – Outama – Cristea/20.
14 It is worth noting that EEAs are called by WECC while RCEs and "no touch" events are called by the Company. While these are often called for the same event, there are some instances where RCEs and EEAs do not perfect align.
15 PGE/300, Schwartz – Outama – Cristea/21.

month that were not declared RCEs for the months of July, August, and September between 2016 and 2022. The result of this analysis is contained in Figure 1 below. It is worth noting that WECC's declared EEAs and PGE's identified "no touch" events do not perfectly align. I include both declared EEAs and PGE's own "no touch" events in the RCE group so that the capacity shortage event group contains data from events that caused market tightness across the WECC and events more local to the Company. Figure 1 clearly demonstrates that in all three months that PGE forecasts RCEs, the wholesale electricity market price is substantially higher than normal. This effect is even more pronounced in HLHs as well.

Figure 1: Average Hourly Mid-C Price Outside RCEs and During RCE

[BEGIN CONFIDENIAL]

[redacted]

[END CONFIDENTIAL]

Q. How do the higher prices associated with RCEs compare to the Mid-C prices that PGE uses in MONET for its NVPC forecast?

A. Based on my review of the Company's LYDIA 2.2 price shape in its MONET model, the highest forecasted hourly Mid-C price was **[BEGIN CONFIENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh. During EEAs and other periods where PGE declared a "no touch" event, there were 96 hours in the summers of 2021 and 2022 where the Mid-C price exceeded the LYDIA-forecasted hourly price. The price was even observed at over $1,000 MWh on multiple occasions.

Q. With all this in mind, do you support the inclusion of an RCE forecast in PGE's 2024 NVPC forecast and a Peak-for-Super Peak contract?

A. Yes. Based on my review, there is ample reason to believe that capacity shortage events will be a continued threat to western grid reliability in the near future and that these costs are not easily modeled in MONET. I support the inclusion of a forecast of RCE costs in the 2024 NVPC forecast.

However, I take issue with the methods PGE employs to forecast these costs and have recommended adjustments to PGE's RCE forecasting method, both within MONET and question whether MONET should even still be used. It is also worth noting that there are various planning initiatives and outcomes that could make these capacity planning model improvements unnecessary or obsolete.

Q. Can you summarize PGE's RCE forecast as proposed?

A. PGE describes its overall method to assign NVPC costs associated with RCEs in PGE/300, Schwarz – Outama – Cristea/25-26. In short, PGE forms its RCE forecast by assuming that the day-ahead forecasted wind generation is zero ahead of RCEs, that there is no market liquidity, and that an additional 146 MW of capacity will be needed for reliability during the super peak period of the selected days. PGE then reserved the needed capacity from its thermal plant to meet the added 146 MW load and the assumed zero wind generation. This is used to forecast a daily RCE cost by month, which is then used to calculate the full RCE NVPC forecast by applying it to the total number of expected RCE days based on a rolling 3-year average of actual RCE days experienced.

Q. How does PGE's NVPC RCE forecast in PGE/300, Schwartz – Outama – Cristea/23 relate to the RCE pass through that PGE proposes in its PCAM proposal in PGE/400, Sims – Outama/4?

A. While they are related, PGE's RCE forecast in the NVPC is a separate issue than the RCE pass through proposed in PGE/400, Sims – Outama/4. The NVPC RCE forecast is meant to set a baseline for expected RCE costs in the ensuing year, whereas PGE's PCAM RCE pass through is a backwards-looking proposal to recover or refund any cost deviations from RCEs in the previous year. I will address only the NVPC RCE forecast in this testimony series. Staff addresses its staunch opposition to the PCAM RCE cost pass through proposal in Staff/2300.

Q. What are your concerns with PGE's RCE forecast as proposed?

A. My main concern is that PGE's proposed NVPC RCE forecast contains elements that do not appear to be reflective of prudent operations. In particular, I believe that PGE's choice to assume no wind available in the day-ahead window to meet demand does not reflect actual available wind generation. This would lead to an overestimation of the amount of power needed from thermal resources or wholesale markets.

Q. Why do you disagree with PGE's choice to assume no wind generation in the day-ahead window when modelling RCEs?

A. In short, I disagree with this choice because wind forecasts in the day-ahead window are generally reliable. While I understand that there are indeed fluctuations in actual wind generation that may be exacerbated by the added load associated with RCEs, assuming no wind generation leads to an overestimation of actual power costs of prudent operation, particularly since PGE could sell any excess wind power on the open market. PGE states that the choice to assume no wind generation is done to align with operational planning and that market sales are assumed to be zero due to market illiquidity.[16] However, I find that neither of these assumptions truly reflects the reality of PGE's operations.

Q. How does PGE's day-ahead wind forecast perform during RCEs?

A. PGE's recent history indicates that the day-ahead wind forecast is highly correlated with actual wind generation during PGE's identified RCE, both in the total quantity of wind produce and the hourly covariance of day-ahead forecasted and actual wind produced. In fact, the actual hourly wind generation is on average 10 percent higher than the forecasted day-ahead wind generation during RCEs.

[16] PGE/300, Schwartz – Outama – Cristea/25.

In response to Staff DR 180, the Company provides workpapers demonstrating the total cost impact of RCEs since 2019 consistent with the methodology discussed in PGE's testimony. Staff used this data response to analyze how closely the differences in the averages of the forecasted and actual wind generation as well as the covariance of these two items.

Q. Why did you look at both the differences in the averages as well as the covariance?

A. I first investigated the differences in the averages to understand whether it appears that PGE's wind is underperforming relative to its forecast during RCEs. If it appears that if the average actual wind generation is lower than the day-ahead forecast, then there would be reason to believe that PGE must incur an added cost to cover the lack of wind generation assuming perfect foresight. Put differently, if actual wind generation was lower than day-ahead forecasted wind generation during a declared RCE, PGE would expect to incur added costs to cover foregone wind generation throughout the course of the year. If instead actual wind generation is higher than forecasted, then PGE would on average not incur any marginal costs of RCEs outside of MONET and could in fact sell the excess power.

With any Variable Energy Resource (VER), there is necessarily a concern that the timing of the forecasted power generation doesn't align with the actual time of generation. If this was the case during a declared RCE, then procuring extra power equivalent to the forecasted day-ahead wind generation may be a necessary step to ensure reliability in a cost-effective manner.

However, I find that the actual wind generation during recent RCEs is substantially higher than what was contained in the day-ahead forecast, and the correlation between these two values is very high.

Q. What were the day-ahead forecasted and actual wind generation in RCEs for the Company since 2020?

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

This indicates that absent any added costs of variability, PGE's wind assets are lowering the cost of RCEs instead of increasing them as PGE's methods assume. However, the variable nature of wind could mean that even if the wind is showing up on average stronger than expected, there could be enough intra-day deviations from the day-ahead forecast that it would make sense to procure the hourly forecasted wind generation as an added reliability measure. To get at this, I measured the Pearson correlation coefficient between the forecasted wind generation and the actual wind generation for all hours during a declared RCE identified in PGE's response to Staff DR 180.

Q. What is the Pearson correlation coefficient?

A. The Pearson correlation coefficient ρ_{XY} for two data series X and Y is as follows:

$$\rho_{XY} = \frac{cov(X,Y)}{\sigma_X \sigma_Y}$$

where $cov(X,Y)$ is the covariance of X and Y, σ_x is the standard deviation of the data series X, and σ is the standard deviation of a data series. The Pearson correlation coefficient by design varies between -1 and 1, with a value near -1 indicating that the two series are negatively, highly correlated, a value near 0 indicating that the two series are uncorrelated, and a value near 1 indicating that the two series are positively and highly correlated.

When it comes to comparing forecasts to actuals, there is no reason to expect that a negative Pearson correlation coefficient should emerge, as this would indicate that a higher day-ahead forecast is predictably correlated with lower actual deliveries in a given hour. A near-zero estimate would indicate that the intra-day wind forecast is very unreliable for predicting actual hourly deliveries. A positive value near 1 would indicate that the day ahead forecast is highly correlated with actual delivered wind at the hourly level.

Q. What is the estimated Pearson correlation coefficient between the day-ahead forecasted hourly wind generation and actual wind generation during RCEs since 2020?

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[redacted] **[END HIGHLY CONFIDENTIAL]**

Q. What is your conclusion regarding PGE's choice to assume zero delivered wind in the day before a declared RCE?

A. My conclusion is that there is no evidence to support this as a prudent business practice when forecasting annual NVPC. PGE's wind assets perform better than forecasted on average during RCEs and actual hourly generation is highly correlated with forecasted hourly generation in the day-ahead window, indicating that PGE's choice to assume zero wind deliveries during a "no-touch event" overestimates NVPC and doesn't even appear to prudently provide reliability benefit.

Q. What do you suggest that PGE do to its RCE forecast in the 2024 NVPC forecast?

A. I suggest that the total marginal RCE cost of $3.9 million be decreased to reflect the cost of past RCEs had PGE not chosen to assume zero wind production in the day-ahead window.

Q. Have you calculated how much this $3.9 million forecast should be scaled back?

A. Yes. Using the Company's confidential attachment to Staff DR 180, I calculated that past RCEs would be only 59 percent as costly if the assumption of zero wind deliveries is removed. Therefore, I recommend that the total RCE forecast cost be scaled down to reflect this. Using this adjustment, the total

RCE NVPC forecast for 2024 is $2.3 million, which is a reduction of $1.6 million in PGE's initial request.

Q. Do you have any other concerns about PGE's inclusion of a forecast of RCE costs in its NVPC.

A. Yes. As PGE outlines in its opening testimony, the costs of RCEs generally come from high demand and market tightness that arise from the intermittent nature of VERs. There are multiple reasons to expect that RCEs and general capacity planning should not present as much of a problem in future NVPC forecasts.

First, storage resources have a clear capacity value that can go over and above their nameplate capacity when considering the Effective Load Capacity Contribution (ELCC). As can be seen in the Company's response to Staff DR 299, which provides the shortlist for PGE's 2021 All Sources Request for Proposals, standalone batteries and batteries co-located with other renewable resources have relatively high ELCCsometimes even over 100 percent.[17] PGE details plans in its most recent IRP to acquire 232 MW of storage by 2030.[18] All else being equal , one would expect there to be enough batteries on PGE's system and across the west that the cost and frequency of these capacity shortfall events would be mitigated. While this outcome may not come for decades, if at all, there are other reasons to expect that the cost of RCEs will be mitigated going forward. One such reason is that PGE is committed to or

17 Staff/302.
18 See page 288 of PGE's 2023 IRP here.

exploring regional initiatives in the nearer term that will help address capacity concerns moving forward, namely the Western Resource Adequacy Program (WRAP) and perhaps the Extended Day-Ahead Market (EDAM).

Q. What is the WRAP?

A. According to its website, the WRAP is administered by the Western Power Pool (WPP) and is the first regional reliability planning and compliance program in the history of the west.[19] Once it is fully operational, the WRAP will consist of two programs to ensure its members are resource adequate. The first part is a seven-month forward showing where each member is required to show that it has the resources to match its monthly P50 peak load plus a planning reserve margin over the period and has firm transmission rights for 75 percent of the load. The forward showing is binding for winter and summer months.

The second part is an operational program where members who are short on capacity can rely on other members who have excess capacity through a sharing mechanism that forecasts capacity needs up to a week ahead. Once operational, WRAP members with deficient capacity can request this excess capacity as late as two hours ahead of a capacity shortage event.

Q. What is the current state of the WRAP?

A. The WRAP tariff was approved by FERC on February 10, 2023, and is currently in a non-binding phase where members are submitting essentially the same information that they will need to once the WRAP is fully operational. As detailed in WPP's FERC tariff filing, the WRAP is still calculating region-wide

[19] See WRAP's homepage here.

planning reserve margins, presenting region-wide resource adequacy data to its members, and allowing members to do some level of capacity sharing.[20] The WPP has a goal of having its first binding season in the summer of 2025 assuming that it has a critical mass of participants and to make all members binding in 2028.

Q. How could the WRAP mitigate the NVPC effects of RCEs?

A. PGE includes a forecast of RCE costs because the cost of acquiring energy from wholesale markets during these exceptionally high demand times is not easily modeled. The binding nature of the WRAP forward showing during the winter and summer months gives some added assurance that its members will be ready for these events should they arise. Further, the WRAP operational program mitigates the need for WRAP members to even transact at an open market during these capacity shortfall events.

Staff Witness Ishraq Ahmed discusses the possible benefits of the EDAM in Exhibit Staff/200, which could further blunt the cost impacts of RCEs for many of the same reasons as the WRAP and CAISO's existing Western EIM.

Q. What do you recommend be done to PGE's modeling to account for its membership in the WRAP and possible membership in the EDAM?

A. I recommend that the Company integrate a forecast of benefits of WRAP membership into its NVPC filing for the 2025 calendar year to account for the first possible binding season. Should the Company choose to join the EDAM, I recommend that the Company do the same.

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[20] See page 7 of the WRAP's tariff filing here.

Q. Does your recommendation change if the first WRAP binding season is delayed?

A. Not entirely. While it is unclear at the moment whether the WRAP will achieve the critical mass of participants necessary to have a fully operational binding program in the 2025 calendar year, the WRAP tariff filing to FERC indicates that the non-binding portion of the WRAP still confers benefits to its members through a limited operational program and valuable region-wide resource adequacy assessment. Although WRAP members are unlikely to realize the full benefits from WRAP during this non-binding period, Staff expects that the non-binding portion could still provide a non-trivial benefit to WRAP participants that would mitigate the NVPC impacts of capacity shortfall events.

Q. Do you have any other recommendations regarding the Company's methods to model the NVPC effects of RCEs?

A. Yes. As I've discussed earlier in this testimony and included in testimony of other Staff members, Staff is not convinced that MONET is the best tool to model NVPC going forward. The Company's proposed RCE forecast is one of many ad hoc adjustments made to MONET to forecast things that the model simply cannot handle. Staff recommends that the Company transition to other forecasting software, such as AURORA, that can better model the nuances of energy markets.

Q. What is your overall recommendation regarding the Company's proposed NVPC forecast of RCEs?

A. I recommend that the Company lower its 2024 forecast of RCEs by $1.6 million. For future NVPC filings, I recommend that the Company integrate the NVPC benefits of being a WRAP member and support the transition to a modeling software that does not require so many ad hoc adjustments to NVPC.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

May 24, 2023

WITNESS QUALIFICATION STATEMENT

NAME:	Curtis Dlouhy
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EDUCATION:	PhD, Economics University of Oregon, Eugene, OR Master of Science, Economics University of Oregon, Eugene, OR Bachelor of Arts, Economics & Math Nebraska Wesleyan University, Lincoln, NE
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) in the Strategy and Integration Division since April 2022 and had previously worked in the Rates, Finance, and Audit Division since June 2020. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have provided analysis and expert testimony in various contested cases including UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394, UG 433, UG 435, UE 399, UE 400, UE 402, and UE 416 (Ongoing). Prior to working for the Commission, I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization, and Antitrust Economics. My PhD dissertation won an award from the Transportation and Public Utility Working Group and covered topics in fossil fuel markets ranging from coal mine closure, dispatchable electricity choices under carbon taxes and coal transport via railroad. While completing my PhD, I provided economic analysis for the Graduate Teaching Fellows Federation as a member of its contract bargaining team.

CASE: UE 416
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Non-Confidential Data Responses in Support Of Opening Testimony

May 24, 2023

PGE's 2021 RFP Final Shortlist

Bidder	Unique Project	Bid Number	Technology	Location	Commercial Structure	2025 MWa	ELCC
18	2	26	Solar + Wind + Battery	WA	Hybrid	206	133
		27	Wind	WA	Hybrid	212	82
		28	Solar + Wind + Battery	WA	Hybrid	303	177
29	3	14	Solar + Battery	WA	PPA	37	64
		15	Solar + Battery	WA	PPA	41	91
	4	16	Solar + Battery	OR	PPA	19	34
31	1	9	Solar + Wind + Battery	WA	Hybrid	137	64
		10	Solar + Wind + Battery	WA	Hybrid	179	103
		11	Wind	WA	Hybrid	113	42
32	2	12	Wind	MT	Hybrid	136	109
43	1	17	Solar	OR	PPA	34	9
		18	Solar + Battery	OR	PPA	36	80
	1	19	Solar	OR	PPA	57	15
		20	Solar + Battery	OR	PPA	58	87
62	3	22	Solar	OR	PPA	11	4
		23	Solar	OR	PPA	11	4
	4	24	Solar + Battery	OR	PPA	11	16
		25	Solar + Battery	OR	PPA	11	15
9	3	1	Battery	OR	PPA	200	124
		2	Battery	OR	PPA	175	115
		3	Battery	OR	PPA	150	100
	4	4	Battery	OR	BTA	75	51
		5	Battery	OR	BTA	50	34
	5	6	Battery	OR	BTA	125	84
		7	Battery	OR	BTA	100	67
		8	Battery	OR	BTA	75	51
16	2	13	Pumped Storage	OR	PPA	197	144
43	3	21	Battery	OR	PPA	100	70
69	1	29	Battery	OR	PPA	100	64

CERTIFICATE OF SERVICE

UE 416

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

Dated this 24th day of May, 2023 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
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UE 416 – SERVICE LIST

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