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June 25, 2019

Via Electronic Filing

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

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY,
2020 Annual Power Cost Update Tariff
Docket No. UE 359

Dear Filing Center:

Please find enclosed the redacted versions of the Opening Testimony and Exhibits of Bradley G. Mullins (AWEC/100-103) and Lance D. Kaufman (AWEC/200-203) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that AWEC's testimony contains Protected Information subject to Order No. 19-112 and is being handled accordingly. The confidential pages of AWEC's testimony will follow to the Commission via Federal Express.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

<u>/s/ Jesse O. Gorsuch</u>
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **confidential pages of the Opening Testimony of the Alliance of Western Energy Consumers** upon the parties shown below via U.S. Mail, postage prepaid, and by posting to the Huddle workspace in this docket.

Dated at Portland, Oregon, this 25th day of June, 2019.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 359

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
2020 Annual Power Cost Update (Schedule 125).	)
	)

OPENING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF

THE ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED VERSION)

June 25, 2019

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EXHIBIT LIST

AWEC/101 – Qualification Statement of Bradley G. Mullins

Confidential AWEC/102 – PGE Gas Optimization Illustration and Quantification

AWEC/103 – PGE Response to AWEC DR 112 in Docket No. UE 335

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 1750 SW Harbor Way, Suite 450, Portland, Oregon 97201.

Q. PLEASE STATE YOUR OCCUPATION AND IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant representing utility customers before state regulatory commissions, with a primary focus in the Northwest. I am appearing on behalf of the Alliance of Western Energy Consumers ("AWEC"), a non-profit trade association whose members are large energy users served by electric and gas utilities located throughout the West, including customers that receive electrical services from Portland General Electric Company ("PGE" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at Exhibit AWEC/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my review of the PGE MONET modeling and Annual Update Tariff ("AUT") Schedule 125 rates for the calendar year 2020. In its filing, PGE has proposed to increase its variable power costs by \$60.5 million, representing a 3.5% rate impact overall, and an impact of up to 5.4% for PGE's largest customers.[1/] This increase is driven by a number of factors such as the loss of production tax credits for Biglow 2 and 3, reduced output from the Boardman Coal Fired Power Plant, and increased market prices.

[1/] PGE/200, Macfarlane/4.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I reviewed PGE's filing and its associated workpapers. I also conducted discovery and reviewed PGE's discovery responses.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. Based on my review of this information, I have developed five recommendations. Specifically, I recommend the Commission require PGE:

1. *To update the Gas Transmission Northwest ("GTN") Pipeline expense to consider the 7.5% rate reduction effective January 1, 2020;*
2. *To include gas optimization margins as an out-of-model adjustment based upon the methodology detailed in Exhibit AWEC/102;*
3. *To forecast wind production using a 75/25 blend of "p50"*[2/] *and historical wind production;*
4. *To remove non-running station service for Boardman, after Boardman is assumed to cease operations on September 30, 2020; and,*
5. *To model the cost of the Boardman coal pile in Boardman dispatch costs.*

Q. ARE ANY OTHER WITNESSES PROVIDING TESTIMONY ON BEHALF OF AWEC IN THIS DOCKET?

A. Yes. Dr. Lance Kaufman is providing testimony on behalf of AWEC in this case discussing Qualifying Facilities, the Energy Imbalance Market, and California-Oregon Border ("COB") trading margins.

Q. WHAT IS THE IMPACT OF AWEC'S RECOMMENDATIONS?

A. The impact of each of these recommendations, including those of Dr. Kaufman, are detailed in Table 1, below.

[2/] I.e., the capacity factor assumed in the respective request for proposals.

TABLE 1
AWEC Recommendations
whole dollars

	PGE Proposed AUT Increase			62,632,136
A1	Mullins	GTN Pipeline Reduction	(499,107)	
A2	Mullins	Gas Optimization	(13,072,670)	
A3	Mullins	Wind Capacity Factor	(9,588,915)	
A4	Mullins	Boardman NRSS	(284,443)	
A5	Mullins	Boardman Coal Pile	(213,022)	
A6	Kaufman	COB Margins	(7,115,908)	
A7	Kaufman	EIM Loss Reduction	(8,764,348)	
		Total Adjustments		(39,538,413)
	AWEC Adjusted AUT Increase			23,093,723

II. GAS TRANSMISSION NORTHWEST PIPELINE RATES

Q. WHERE IS THE GAS TRANSMISSION NORTHWEST PIPELINE?

A. The GTN Pipeline delivers gas from Kingsgate on the Canada-Idaho border to Malin on the California-Oregon border. It crosses the Williams pipeline at Stanfield, near Carty and Coyote Springs. PGE reserves approximately [redacted] dth/day over 300 miles of the GTN Pipeline, which PGE uses to fuel its Carty and Coyote Springs facilities. PGE's GTN Pipeline rights are also interconnected with PGE's rights on pipelines into Canada, including the Foothills pipeline and the Trans Canada pipeline system. With these rights, PGE can access relatively inexpensive gas from Alberta on the NOVA system or AECO market hub, and deliver it to the Stanfield area for use in its power plants, or for transportation onto the Williams system. These rights may be seen in Confidential Figure 1, below

CONFIDENTIAL FIGURE 1

MAP of PGE Transportation Rights

Dth/Day – Red: GTN Pipeline, Green: NW Pipeline

[redacted]

Q. DOES PGE'S FORECAST INCLUDE EXPENSES ASSOCIATED WITH THE GTN PIPELINE?

A. Yes. Including lateral service, PGE forecast $[redacted] associated with the GTN Pipeline. Of this amount, $[redacted] was associated with pipeline reservation costs on the main pipeline, with approximately $[redacted] for the Carty facility and $[redacted] for the Coyote Springs facility. The remainder consists of lateral services, with $[redacted] for Carty lateral service and $[redacted] for Coyote Springs lateral service.

Q. HOW WERE THE PIPELINE RESERVATION FEES CALCULATED?

A. The workpapers supporting this amount may be found in PGE's April 15, 2019 workpapers at Vol 5 - Contracts\Gas Transportation, specifically in the confidential file "#GasTransCost_2020AUT_03072019". As can be seen on the Tab "GasTrans", PGE uses a non-mileage rate of $[redacted] dth/day and a mileage rate of $[redacted] dth/day for calculating the pipeline reservation fees on the main pipeline.

Q. WHERE DID PGE GET THOSE RATES?

A. Those rates are from the settlement between shippers and the GTN Pipeline filed with the Federal Energy Regulatory Commission on October 16, 2018 ("GTN Stipulation"). The rates PGE used, however, were the rates effective January 1, 2019, from the GTN Stipulation. PGE did not consider that, under the GTN Stipulation, an additional 7.4% rate reduction is scheduled for January 1, 2020. The additional reduction on January 1, 2020 may be seen in Docket No. UE 356, Exhibit No. AWEC/103, Mullins/41.[3/] The declining trajectory for GTN rates are summarized further in Table 2, below.

TABLE 2
GTN Pipeline Rates Reductions

	Mileage Rate	% Δ	Non-Mileage Rate	% Δ
January 1, 2018	0.000434		0.034393	
January 1, 2019	0.000391	-9.9%	0.030954	-10.0%
January 1, 2020	0.000362	-7.4%	0.028612	-7.6%

As can be seen, rates declined on January 1, 2019 by approximately 10%. PGE captured the January 1, 2019 reduction in its November update in the 2019 AUT.

3/ Pursuant to OAR 860-001-0460(1)(d), and for purposes of administrative efficiency, AWEC requests that the Commission take official notice in this Docket of Exhibit AWEC/103 in Docket No. UE 356.

Notwithstanding, rates are set to further decline by an additional 7.5% on January 1, 2020. PGE used the January 1, 2019 rates in this filing, which have not yet been updated to January 1, 2020 levels.

Q. WAS PGE A PARTY TO THE GTN STIPULATION?

A. Yes. PGE was an active party in negotiating the GTN Stipulation rate reductions. AWEC was also involved in negotiating that settlement and was a party to it.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the proper GTN Pipeline rates for 2020 be used in the MONET model forecast in this proceeding. The impact is an approximate $499,107 reduction to net power costs.

III. GAS OPTIMIZATION MARGINS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend PGE include an out-of-model adjustment to account for gas optimization activities, considering PGE's access to extra-regional gas markets and its access to the North Mist Storage facility. As detailed in Exhibit AWEC/102, that adjustment results in a $13,072,670 reduction to power costs.

Q. WHAT IS GAS OPTIMIZATION?

A. PGE maintains pipeline rights over a broad geographic region and has many opportunities to purchase and sell gas in order to optimize the cost associated with fueling its system. These activities include purchasing at one hub and transporting to another in order to earn a margin on the price difference between the two locations. PGE's modeling of gas supply costs, however, is based only on the location of each individual plant, and therefore does not consider the beneficial aspects of how PGE monetizes its gas transportation rights. In actual operations

PGE conducts trading activities that result in a reduction to power costs that offsets the cost of fuel at PGE's gas plants.

Q. HOW DOES PGE BENEFIT WITH RESPECT TO ITS GAS TRANSPORTATION RIGHTS?

A. Similar to electricity prices, natural gas prices differ depending on the location of a transaction. Accordingly, if an entity owns gas transportation rights between two locations, it can buy at one location and sell at the other, earning a margin, or basis, equal to the difference in price between the two locations. Since PGE needs fuel to run its power plants, it obviously cannot monetize the basis between two locations at all times, but it still benefits because it is often able to obtain a cheaper source of fuel for the power plant than if the fuel were acquired locally at the location of the power plant. Further, when a plant is not operating, PGE's trading floor can transport and resell gas to earn a trading margin based on the spreads between the prices at the point of delivery and receipt. The potential value of basis spreads in the West was recently illustrated following the rupture on the Enbridge pipeline. On March 5, 2019, Sumas Gas prices were $15.63/MMBtu, compared with Kingsgate prices equal to $4.00/MMbtu.[4/] Thus, with such large price differentials between the two locations, shippers on the GTN Pipeline were earning a basis equal to $11.63/MMBtu, a margin of 290%.

Q. WHAT IS THE EXTENT OF PGE'S GAS TRANSPORTATION RIGHTS?

A. These have been detailed in Confidential Figure 1, above. In addition to PGE's [redacted] dth/day of transportation rights on the GTN Pipeline discussed above, PGE also has [redacted] dth/day of transportation rights on the NW Pipeline, which PGE uses to serve the Beaver and Port Westward complex. PGE's NW Pipeline rights are somewhat more complicated since they are broken into several contracts.

4/ Source: Enerfax Daily.

Q. HAVE PGE'S TRANSPORTATION RIGHTS CHANGED RECENTLY?

A. Yes. There are at least two major changes that have occurred with respect to PGE's pipeline rights in recent years. First, PGE had historically released [redacted] dth/day rights of its transportation capacity on the Williams pipeline between Kern River and Stanfield.[5/] That contract expired in [redacted], so the pipeline capacity to Kern River and Stanfield has reverted to PGE. Second, PGE now has access to the North Mist Storage facility, which further improves PGE's ability to optimize its gas costs. PGE began injections into the North Mist Storage facility in 2018 and will be capable of withdrawing gas in the AUT period.

Q. DOES THE MONET MODEL CAPTURE THE FINANCIAL BENEFITS ASSOCIATED WITH PGE'S TRANSPORTATION AND STORAGE AGREEMENTS?

A. Not fully. PGE's model captures part of the financial benefit of its transportation rights into AECO through the GTN Pipeline. PGE's model, however, assumes no financial benefit associated with its rights on the NW Pipeline system and no financial benefit associated with its rights to the North Mist Storage facility.

With respect to PGE's access to AECO in Canada, PGE's model captures some of the financial benefits of its Canadian pipeline rights by dispatching the Carty and Coyote Springs plants at AECO prices, even though those facilities are located in the Stanfield area. Thus, when Carty and Coyote Springs are dispatching, the price differential between the AECO and Stanfield hubs is captured in PGE's modeling. Notwithstanding, the Carty and Coyote Springs plants do not dispatch in every hour of the year. In hours when those plants are not running, or are running at reduced capacity, PGE still has the opportunity to further monetize the price spreads between AECO and Stanfield by reselling gas into the Stanfield or Sumas markets.

5/ PGE's Northwest Pipeline transportation contracts may be found in its April 15, 2019 workpapers at "Vol 5 - Contracts\Gas Transportation\Beaver-Port Westward."

With respect to its NW Pipeline rights, PGE's Clatskanie facilities (Beaver, Port Westward and Port Westward II) are dispatched in MONET based on Sumas prices. Sumas is the locational price for the Clatskanie facilities, so the modeling for those plants do not consider any transportation capability on the NW Pipeline system from Stanfield, nor to the Rockies.

Finally, PGE has not made any adjustment to account for the financial impact of its capacity at the North Mist Storage facility. The North Mist Storage facility provides a significant benefit to the Company because PGE is capable of injecting gas into storage when it is inexpensive and withdrawing gas when it is more expensive. Further, PGE's injection and withdrawal rights in the North Mist Storage facility are significant. PGE has the ability to withdraw [redacted] dth/day and inject [redacted] dth/day, providing PGE with financial benefits that don't get captured in the Sumas gas prices used in its model.

Q. DOES PGE'S FORECAST INCLUDE COSTS OF THE NORTH MIST STORAGE FACILITY?

A. Yes. PGE's forecast includes $[redacted] in costs associated with its rights to the North Mist Storage facility.

Q. DO OTHER UTILITIES MODEL GAS OPTIMIZATION ACTIVITIES WHEN FORECASTING POWER SUPPLY COSTS?

A. Yes. Avista Corporation models gas optimization costs as an out-of-model adjustment in the power supply forecasts it uses for ratemaking. Avista owns the Coyote Springs II power plant and is a co-owner with PGE in common facilities at the Coyote Springs complex. Similar to PGE, Avista uses its gas transportation rights on the GTN Pipeline system and into Canada to fuel the Coyote Springs II power plant.

In Avista's 2018 General Rate Case before the Washington Utilities and Transportation Commission, Avista's initial power cost forecast included gas optimization revenues of $9,000,000.[6/] That amount was calculated by taking the basis spreads between AECO and Stanfield gas prices over every hour of the year, including hours when Avista's plants were not running.

I recommend that PGE model gas optimization activities using a similar methodology as Avista, although it is necessary to account for some of the differences in modeling approaches between the two utilities.

Q. HAVE YOU PREPARED AN EXHIBIT DETAILING YOUR CALCULATION?

A. Exhibit AWEC/102 provides an analysis of PGE's gas optimization activities. As can be noted in this exhibit, I have categorized PGE's optimization activities into three different categories: GTN Pipeline, NW Pipeline, and North Mist Storage.

Q. HOW DID YOU MODEL THE FINANCIAL BENEFITS OF THE GTN PIPELINE

A. First, with respect to PGE's transportation from AECO on the GTN Pipeline, I modeled PGE's ability to monetize spreads between AECO and Stanfield, but only in hours when Carty or Coyote Springs were not operating. Since PGE dispatches Carty and Coyote Springs to AECO prices, a financial adjustment is only necessary in hours when the facilities are not running. Note that this is slightly different from the approach Avista uses because Avista dispatches Coyote Springs II at the locational, Stanfield prices, but considers the value of the basis spread between Stanfield and AECO in all hours of the year, not just the hours the plant is not running. In the exhibit, I determine the monthly price differential, and multiply that by the

[6/] See WUTC vs. Avista Corporation, Docket No. UE-170485 (Consolidated), Exhibit WGJ-2, Line 36.

percentage of hours in the month when the plant was not running to determine the portion of the financial benefit not considered in PGE's model.

Q. HOW DID YOU MODEL PGE'S RIGHTS ON THE NW PIPELINE?

A. I included an adjustment to consider PGE's rights on the NW Pipeline system, including transportation between the Rockies and Stanfield, and then from Stanfield to Sumas. PGE dispatches its Clatskanie facilities to Sumas prices, so a financial adjustment for these segments is necessary in all hours of the year. Accordingly, I applied this adjustment by multiplying the monthly basis differential by the number of dth that PGE is capable of transporting over the course of a month on the NW Pipeline.

Q. HOW DID YOU MODEL PGE'S ACCESS TO NORTH MIST STORAGE FACILITY?

A. Modeling North Mist Storage optimization was somewhat more difficult, because the magnitude of flexibility of PGE's storage capability does not get captured in the monthly price spreads. PGE's rights are so significant, it is capable of withdrawing and injecting its entire capacity many times over the course of a month. Notwithstanding, using the monthly prices, I developed a withdrawal and injection profile designed to maximize margins on the withdrawal and injection activity on a monthly basis. This profile is not necessarily an accurate representation of how PGE will use the North Mist Storage facility, since I expect PGE will withdraw and inject more frequently than monthly. Therefore, using the monthly profile is likely a conservative way to analyze the financial benefits, since more granular withdrawal activity would likely increase PGE's margins on the gas it stores in North Mist.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. As can be seen in AWEC/102, the impact of this recommendation is an approximate $13,072,670 reduction to net power costs.

IV. WIND CAPACITY FACTORS

Q. PLEASE SUMMARIZE YOUR CONCERN WITH THE WIND CAPACITY FACTORS PGE HAS MODELED IN MONET.

A. In recent AUT filings, PGE has made several downward adjustments to the capacity factors it assumes for owned wind resources: Biglow Phase 1, Biglow Phase 2, Biglow Phase 3, and Tucannon River. In Docket No. UE 335, for example, PGE proposed to reduce the capacity factor of these four wind facilities by approximately 4%. This Docket continues this trend of reduced capacity factors. PGE's forecast proposes to further reduce the production estimates for PGE's owned wind resources by an additional 0.6%. From a ratepayer perspective, reducing the capacity factor assumed for ratemaking for PGE's owned wind resources is an unfair result, particularly when one considers representations made in the respective request for proposal ("RFP") processes that led PGE to develop these wind resources. Accordingly, for purposes of modeling the capacity factor of wind resources in MONET, I recommend PGE use a production estimate that is a blend of the estimate assumed when the resources were selected in the respective RFPs and the actual production.

Q. WHAT CAPACITY FACTOR HAS PGE PROPOSED TO USE TO ESTIMATE WIND PRODUCTION IN THE AUT PERIOD?

A. That information is provided in Table 3, below.

TABLE 3

RFP vs. Historical Average Capacity Factor of PGE Owned Wind Plant[7/]

	Biglow 1	Biglow 2	Biglow 3	Tucannon
2012	30.6%	28.6%	25.5%	38.2%
2013	32.8%	31.0%	27.5%	38.2%
2014	31.1%	29.4%	26.9%	38.2%
2015	28.9%	26.9%	24.3%	32.6%
2016	29.5%	27.2%	24.3%	37.3%
2017	24.4%	23.5%	20.7%	30.5%
2018	27.4%	28.0%	24.4%	35.9%
7-yr Avg 2012 - 2018	29.3%	27.8%	24.8%	35.8%
5-yr Avg 2014-2013	28.3%	27.0%	24.1%	34.9%

Table 3 show the historical capacity factors of PGE's owned wind plants. Color scales are applied to the historical date. Note that blue represents an above-average wind production year and red represents a below-average wind production year, for each resource. In PGE's initial filing, the production forecast for owned wind resources was based on the average over the period 2014-2018. PGE's practice of using a 5-year rolling average for its wind production estimates has resulted in a reduction to the capacity factors assumed in this filing. The reduction was due to the fact that 2017 was a poor year for wind generation in the Northwest, as indicated by the color scales applied to the historical capacity factors in Table 1. Further, calendar year 2013, the year rolling off of PGE's historical averaging period, was a relatively good year for wind production in the Northwest.

7/ Historical production is available through FERC Form 1. For Tucannon, PGE uses the 38.2% forecast from the 2016 GRC prior to the online date of Tucannon in 2012-2013.

Q. IS FIVE YEARS OF HISTORICAL WIND GENERATION SUFFICIENT TO BE USED AS A FORECAST?

A. No. Like hydro resources, the output from wind resources is variable year to year. While wind output has tended to be less variable than hydro output, five years is not a sufficient amount of time to make long-term conclusions about the capacity factor expected from PGE's owned wind resources. When measuring the capacity factors over such a short time frame there is the potential for a few bad years to drive down the five-year average capacity factor such that it is not consistent with the capacity factor expected in the long term. Or, in contrast, a few good years may drive up the average capacity factor, causing it to exceed the expected long-term production. Given the low production levels in 2017, it is not known, for example, if the experience in 2017 is an outcome to be expected once every five years, or once every eighty years. Further, it is possible that conditions similar to 2012 and 2013 might persist in the test period, yet those production amounts are not considered in the historical averaging period.

Q. HOW DOES THE CURRENT FIVE-YEAR AVERAGE COMPARE TO THE VALUES ASSUMED IN THE REQUEST FOR PROPOSALS FOR THE RESPECTIVE RESOURCES?

A. PGE provided the RFP capacity factors assumed for its owned wind resources in response to AWEC DR 112 in Docket UE 335, which has been attached as Exhibit AWEC/103. Table 4, below, details the RFP capacity factors for PGE's resources, and compares that to the production estimates PGE proposes to use in this docket.

TABLE 4
RFP Capacity Factors of PGE Owned Wind Resources versus PGE Proposed

	Biglow 1	Biglow 2	Biglow 3	Tucannon
RFP Cap. Fact.	31.0%	31.0%	31.0%	38.4%
PGE Proposed	28.3%	27.0%	24.1%	34.9%
Delta (abs. %)	-2.7%	-4.0%	-6.9%	-3.5%
Delta (% of %)	-9%	-13%	-22%	-9%

As can be noted, the average production estimates PGE proposes, based on 5 years of historical data, are significantly lower than the estimates that were made at the time the resources were selected for procurement. Biglow 3, for example, has been producing at a level that is 22% less than the amount that was assumed in the RFP. Based on the reductions to the capacity factors PGE is proposing, the projects are not providing nearly the level of benefits in rates as PGE represented in the RFP processes.

Q. WHY ARE THESE REDUCED CAPACITY FACTORS PROBLEMATIC FROM A RATEMAKING PERSPECTIVE?

A. The expected capacity factors are particularly impactful when making decisions about whether to acquire a utility-owned resource in the RFP. Had PGE's assessment of these capacity factors been more in line with actual experience, PGE may have made a different resource decision. Of course, the Commission cannot now revisit the prudence determination it made before it knew what the actual production levels of PGE's wind resources would be. From a ratepayer perspective, that is an unfair result because investors are recognizing all of the equity returns associated with PGE's wind facilities, while ratepayers are bearing all of the risk of the benefits of the investment failing to materialize at the level promised when the investment was made. This is in contrast to a power purchase agreement, such as Vansycle Ridge, where PGE would only pay for the actual output from the contracted resource, thus putting the risk of underperformance on the developer.

It is critical, therefore, that utilities bear some risk that the wind might not blow at the level forecast when wind resources are selected in an RFP process, since other resource options were available in the RFPs. The initial production estimates are significant because if wind output fails to materialize at the level forecast in the RFP, ratepayers might have preferred another resource alternative, such as a power purchase agreement.

Q. WHAT IS A REASONABLE WAY TO DEAL WITH THE CAPACITY FACTOR RISK WITH PGE'S OWNED WIND RESOURCES?

A. For ratemaking purposes, using a blend of the RFP estimate and actuals is a reasonable way to ensure that the risks associated with the capacity factors of utility-owned wind resources are fairly shared between investors and ratepayers. In circumstances such as this, where the generating facilities have not performed at the level assumed when the investment decision was made, it is appropriate for both ratepayers and shareholders to bear the cost of the failure. Note also that this proposal is symmetrical in that, if in the future PGE's wind resources outperform their p50 forecasts, shareholders will retain a portion of this benefit.

Q. WHAT DO YOU RECOMMEND?

A. I recommend using a 75/25 blend between the RFP estimate and actuals when modeling the production of owned wind resources in the MONET model. I have detailed this calculation in Table 5, below.

TABLE 5
AWEC Proposed Wind Capacity Factors
Using 75/25 blend of p50 and historical production

	Biglow 1	Biglow 2	Biglow 3	Tucannon
RFP Cap. Fact.	31.0%	31.0%	31.0%	38.4%
7-year Average	29.3%	27.8%	24.8%	35.8%
75/25 Weighting	30.6%	30.2%	29.4%	37.8%

Q. SHOULD PGE'S INVESTORS BEAR ALL OF THE RISK ASSOCIATED WITH ITS PRODUCTION ESTIMATES?

A. PGE cannot control the wind, or how much it blows. Further, while it is expected that PGE will make its best efforts to develop a reasonable forecast, no forecast is perfect. Accordingly, it is reasonable for ratepayers to share some of the production risk associated with PGE's wind resources. In weighing the considerations of both customers and shareholders, I arrived at the conclusion that the most reasonable approach is to use a weighted blend of the RFP estimate and actual capacity factors, as described above, to assign some of the production risk to customers while recognizing that it was PGE's decision to pursue these resources and PGE was the entity that had all of the information to determine which resources to select. Thus, PGE should bear a majority of the risk associated with the capacity factors of its wind resources.

An asymmetrical sharing of power forecasting risks is also consistent with Commission policy, which has found this to be necessary to ensure revenue neutrality. PGE's power cost adjustment mechanism includes dead bands in which the Company absorbs up to $30 million in excess power costs and retains up to $15 million in lower-than-anticipated power costs. The Commission's orders approving this arrangement relied specifically on the fact that this asymmetry was necessary because the cost of purchasing replacement power in years when forecasts of plant output are higher than realized outweighs the power cost benefits when forecasts of plant output are lower than realized (because market prices will be correspondingly lower).[8/]

In addition, it is important to recognize that my proposal is purely a forecasting approach used for ratemaking purposes. I am not proposing to use these capacity factors in PGE's power cost adjustment mechanism. Thus, PGE will still have the opportunity to recover its prudently incurred actual power costs through the power cost adjustment mechanism, if actual production is persistently below the estimate used for ratemaking.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Applying my recommendation results in a $9,588,915 reduction to net power costs. To calculate this adjustment, I changed the capacity factor estimates in the PC Input tab of MONET. I did not adjust any of the scaling factors used to establish hourly wind profiles.

V. BOARDMAN NON-RUNNING STATION SERVICE

Q. WHAT IS NON-RUNNING STATION SERVICE?

A. Non-running station service is the electrical requirements of a power plant when the plant is not running. When a power plant is running, the electrical production from the power plant is used to serve the plant's own requirements, such as pumps, motors, lighting, and other electronic equipment necessary to keep the power plant operational. When the power plant is running, these requirements are considered an offset to the net output of the power plant. When a power plant is not running, however, these electrical requirements must be provided from the electrical grid.

8/ UE 215, Order No. 10-478 at 10 (Dec. 17, 2010); UE 180/UE 181/UE 184, Order No. 07-015 at 26 (Jan. 12, 2007); UE 165/UM 1187, Order No. 05-1261 at 10 (Dec. 21, 2005).

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO BOARDMAN NON-RUNNING STATION SERVICE?

A. PGE assumes that Boardman will be consuming station service after it has ceased operations on September 30, 2020. I disagree with this assumption. After Boardman ceases operations the electrical requirements of the plant are better considered a decommissioning cost, rather than an ongoing power cost. Further, the power requirements after the facility has ceased operation will decline since many of the pumps and electrical equipment associated with the facility will no longer be consuming electricity.

Q. WHAT IS THE IMPACT OF REMOVING BOARDMAN STATION SERVICE AFTER SEPTEMBER 30, 2020?

A. Removing the station service requirement for Boardman after September 30, 2020 results in an approximate $304,220 reduction to net power costs.

Q. DID PGE INCLUDE ANY OTHER BOARDMAN COSTS AFTER THE PLANT HAS CEASED OPERATIONS?

A. In addition to non-running station service, PGE includes approximately $19,777 in coal car depreciation and rail car mileage taxes. These relatively small amounts should also be removed after the September 30, 2020 closure date, so I added these amounts to the NRSS adjustment detailed in Table 1, above.

VI. BOARDMAN COAL PILE

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE BOARDMAN COAL PILE?

A. PGE models the cost of Boardman assuming all of the coal burned during the calendar year is acquired from the market. Notwithstanding, PGE will be starting the year with a coal pile that cost less than the market rate for coal during the calendar year. This is evident from the PC input tab of MONET. On row 855, PGE notes that it expects to have an initial coal pile of [redacted] tons and that it will purchase [redacted] tons from the market. The initial coal pile had a cost of $[redacted]/ton, in contrast $[redacted]/ton for market purchases. Notwithstanding, PGE assumed all coal was purchased at the market rate.

Since all of the coal in the coal pile will be burned in 2020, I recommend PGE include the slightly lower-cost coal from the coal pile when determining the cost of Boardman dispatch.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. Pricing the initial coal pile results in an approximate $213,022 reduction to power costs.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

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EXHIBIT AWEC/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. I have been performing independent utility consulting services on matters such as power costs, revenue requirement, rate spread and rate design for approximately five years, and have sponsored testimony in several regulatory jurisdictions, including before the Oregon Public Utility Commission. Previously, I worked at PacifiCorp as an analyst involved in power supply cost forecasting. I also previously worked at Deloitte, where I ultimately specialized in research and development tax incentives. I have a Master of Science degree in Accounting from the University of Utah.

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

A. I have sponsored testimony in the following regulatory proceedings:

- In re PacifiCorp, 2020 Transition Adjustment Mechanism, Or.PUC Docket No. 356.
- In re PacifiCorp 2020 Renewable Adjustment Clause, Or.PUC Docket No. 352.
- 2020 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-20.
- In the Matter of the Application of MSG Las Vegas, LLC for a Proposed Transaction with a Provider of New Electric Resources, PUC Nv. Docket No. 18-10034.
- Puget Sound Energy 2018 Expedited Rate Filing, Wa.UTC Dockets UE-180899/UG-180900 (Cons.).
- Georgia Pacific Gypsum LLC's Application to Purchase Energy, Capacity, and/or Ancillary Services from a Provider of New Electric Resources, PUC Nv. Docket No. 18-09015.
- Joint Application of Nevada Power Company d/b/a NV Energy for approval of their 2018-2038 Triennial Integrated Resource Plan and 2019-2021 Energy Supply Plan, PUCN Docket No. 18-06003.

- In re Cascade Natural Gas Corporation Request for a General Rate Revision, Or.PUC, Docket No. UE 347.

- In re Portland General Electric Company Request for a General Rate Revision, Or.PUC Docket No UE 335.

- In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Or.PUC Docket No. UG 344.

- In re Cascade Natural Gas Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-170929.

- In the Matter of Hydro One Limited, Application for Authorization to Exercise Substantial Influence over the Policies and Actions of Avista Corporation, Or.PUC, Docket No. UM 1897.

- In re PacifiCorp, dba Pacific Power, 2016 Power Cost Adjustment Mechanism, Or.PUC, Docket No. UE 327.

- In re Avista Corporation 2018 General Rate Case, Wa.UTC Dockets UE-170485 and UG-170486 (Consolidated).

- Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUCN. Docket No. 17-06003.

- In re the Application of Rocky Mountain Power for Authority to Decrease Current Rates by $15.7 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates By $528 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism, Wy. PSC, Docket No. 20000-514-EA-17 (Record No. 14696).

- In re the 2018 General Rate Case of Puget Sound Energy, Wa.UTC, Docket No. 170033 (Cons.).

- In re PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 323.

- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 319.

- In re Portland General Electric Company, Application for Transportation Electrification Programs, Or.PUC, UM 1811.

- In re Pacific Power & Light Company, Application for Transportation Electrification Programs, Or.PUC, Docket No. UM 1810.
- In re the Public Utility Commission of Oregon, Investigation to Examine PacifiCorp, dba Pacific Power's Non-Standard Avoided Cost Pricing, Or.PUC, Docket No. UM 1802.
- In re Pacific Power & Light Co., Revisions to Tariff WN U-75, Advice No. 16-05, to modify the Company's existing tariffs governing permanent disconnection and removal procedures, Wa.UTC, Docket No. UE-161204.
- In re Puget Sound Energy's Revisions to Tariff WN U-60, Adding Schedule 451, Implementing a New Retail Wheeling Service, Wa.UTC, Docket No. UE-161123.
- 2018 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-18.
- In re Portland General Electric Company Application for Approval of Sale of Harborton Restoration Project Property, Or.PUC, Docket No. UP 334 (Cons.).
- In re An Investigation of Policies Related to Renewable Distributed Electric Generation, Ar.PSC, Matter No. 16-028-U.
- In re Net Metering and the Implementation of Act 827 of 2015, Ar.PSC, Matter No. 16-027-R.
- In re the Application of Rocky Mountain Power for Approval of the 2016 Energy Balancing Account, Ut.PSC, Docket No. 16-035-01
- In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-160228 (Cons.).
- In re the Application of Rocky Mountain Power to Decrease Current Rates by $2.7 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 and to Increase Rates by $50 Thousand Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-292-EA-16.
- In re PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 307.
- In re Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125), Or.PUC, Docket No. UE 308.
- In re PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol, Or.PUC, UM 1050.

- In re Pacific Power & Light Company, General rate increase for electric services, Wa.UTC, Docket No. UE-152253.

- In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent, Wy.PSC, Docket No. 20000-469-ER-15.

- In re Avista Corporation, General Rate Increase for Electric Services, Wa.UTC, Docket No. UE-150204.

- In re the Application of Rocky Mountain Power to Decrease Rates by $17.6 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 to Decrease Rates by $4.7 Million Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-472-EA-15.

- Formal complaint of The Walla Walla Country Club against Pacific Power & Light Company for refusal to provide disconnection under Commission-approved terms and fees, as mandated under Company tariff rules, Wa.UTC, Docket No. UE-143932.

- In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 296.

- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 294.

- In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation, Or.PUC, Docket No. UM 1662.

- In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction, Or.PUC, Docket No. UM 1712.

- In re Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Or.PUC, Docket No. UM 1719.

- In re Portland General Electric Company, Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions, Or.PUC, Docket No. UM 1623.

- 2016 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-16.

- In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes, Wa.UTC, Docket No. UE-141368.

- In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million, Wa.UTC, Docket No. UE-140762.

- In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs, Wa.UTC, Docket No. UE-141141.

- In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent, Wy.PSC, Docket No. 20000-446-ER-14.

- In re Avista Corporation, General Rate Increase for Electric Services, RE, Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015, Wa.UTC, Docket No. UE-140188.

- In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market, Or.PUC, Docket No. UM 1689.

- In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 287.

- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 283.

- In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU), Or.PUC, Docket No. UE 286.

- In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment, Or.PUC, Docket No. UE 281.

- In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck), Or.PUC, Docket No. UE 267.

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EXHIBIT AWEC/102

PGE GAS OPTIMIZATION ILLUSTRATION AND QUANTIFICATION

(REDACTED)

Exhibit AWEC/102 contains Protected Information Subject to Order No. 19-112 and has been redacted in its entirety.

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EXHIBIT AWEC/103

PGE RESPONSE TO AWEC DATA REQUEST 112 IN DOCKET NO. UE 335

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 112
Dated May 4, 2018

Request:

For Biglow (1, 2 & 3) and Tucannon, please identify the capacity factor that was assumed in the request for proposals where the respective wind resources were selected.

Response:

A capacity factor was not assumed in the request for proposals (RFPs) that ultimately resulted in the construction of the Biglow Canyon Wind Farm (Biglow) and Tucannon River Wind Farm (Tucannon). The bids provided in response to PGE's RFPs did include a capacity factor for the projects that ultimately resulted in the construction of Biglow 1, 2, and 3 and Tucannon. The project that ultimately became Biglow was bid into PGE's 2004 All-Source RFP as a purchase power agreement wind project with a capacity factor of approximately 31%.

The winning bid in PGE's 2011 Renewable RFP that ultimately became Tucannon provided a capacity factor of 38.4%. However, at the request of the Independent Evaluator, studies from all the submitted bids were reviewed by DNV KEMA, an independent consulting firm. DNV KEMA's study estimated the projected net capacity factor of Tucannon over the first 20 years of operation, based on a probability of exceedance of 50 percent, to be approximately 36.8 percent.

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OPENING TESTIMONY OF

LANCE D. KAUFMAN

ON BEHALF OF

THE ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED VERSION)

June 25, 2019

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lance D. Kaufman, and my business address is 4801 W. Yale Ave. Denver, CO 80219.

Q. PLEASE STATE YOUR OCCUPATION AND IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a consultant performing statistical and economic analysis related to the utility industry, employment, and general business. I am appearing on behalf of the Alliance of Western Energy Consumers ("AWEC"), a non-profit trade association whose members are large energy users served by electric and gas utilities located throughout the West, including customers that receive electrical services from Portland General Electric Company ("PGE" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at Exhibit AWEC/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my review of PGE's Net Variable Power Cost ("NVPC") forecast and Annual Update Tariff ("AUT") Schedule 125 rates. I address issues related to market transactions, Qualifying Facilities, Boardman operations, and retail sales. I provide recommendations related to those issues, and support these recommendations. Bradley G. Mullins is also providing testimony on behalf of AWEC in this case.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I reviewed PGE's filing and its associated workpapers, conducted discovery, reviewed PGE's discovery responses, and attended a workshop hosted by the OPUC Staff. Based on my review of this information, I have developed the following recommendations:

1. *COB Trading Margin Issue*

    a. *Calculate historic COB trading margin using the difference between the PowerDex Mid-Columbia hourly price index and the actual COB transaction price.*

    b. *Calculate forecasted COB trading margin benefits using a three-year average of historic COB trading margin benefit.*

2. *Energy Imbalance Market: Greenhouse Gas Awards*

    a. *Forecast greenhouse gas awards using the most recent 12 months of data available for the November update with no adjustment for CAISO rule changes.*

3. *Energy Imbalance Market: Market Losses*

    a. *Calculate forecasted Energy Imbalance Market benefits by excluding historic market losses for the fifteen-minute market and real-time-dispatch.*

4. *Qualifying Facilities*

    a. *Calculate forecasted qualifying facilities ("QF") volume using the contract delay rate method employed by PacifiCorp in the Transition Adjustment Mechanism with no true-up.*

    b. *If the forecast does not use the contract delay rate method, modify the true-up calculations to adjust for actual sales.*

5. *Boardman: Supply Chain Constraints*

    a. *Implement derations sequentially over time.*

    b. *Calculate shortage using Boardman monthly dispatch from prior step. Implement supply related derations as a final step.*

c. *Model derations as 100 percent outages for enough hours to meet supply constraints. Where possible, time outages to coincide with lowest market prices or lowest shadow price for Boardman energy.*

d. *Model January 2020 coal pile as if PGE implemented Boardman shutdowns in 2019 sufficiently to equate NVPC impact of 2019 shutdowns with the forecasted 2020 NVPC shutdowns.*

6. *Boardman: End of Operations*

a. *Allow MONET to operate in Q4 while supplies last, but do not model fuel deliveries in Q4.*

7. *Short-Term Direct Access Load*

a. *Exclude Short-Term Direct Access Load from November Update load forecast.*

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS?

A. The impact of two of these recommendations is detailed in Table 1, below. My other recommendations will also have an impact on PGE's NVPC, but their impact has not been quantified at this time because they require changes to PGE's MONET model, which PGE should perform, or will be known when PGE provides its NVPC update in November.

Table 1: Summary of NVPC Adjustments

COB Margin Benefit Increase	$7,115,908
EIM Loss Reduction	8,764,348
Total	15,880,256

II. CALIFORNIA-OREGON BORDER MARKET TRANSACTIONS

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE's opening testimony discusses the California-Oregon Border ("COB") trading margin issue. However, the Company's testimony provides little information about the issue. AUT parties have raised concerns with PGE's treatment of COB market transactions in every AUT and general rate case since Docket No. UE 294. In Docket No. UE 294, Mr. Mullins demonstrated that PGE's NVPC forecast did not account for access to important power markets, including the COB Market. The primary concern is that when PGE is not transmission constrained, PGE can make economic transactions at the COB market that reduce power costs. If PGE's NVPC forecast does not account for these economic transactions, the NVPC forecast will be too high. In Order No. 15-356, the Commission ordered PGE to propose a methodology to capture, for purposes of the AUT, the value of benefits PGE obtains through transactions at COB made possible by transmission rights paid for by PGE ratepayers. In the following AUT docket, UE 308, PGE proposed a methodology that utilized historic transaction volumes with a margin value based on forward prices.[1/]

OPUC Staff have raised concerns with PGE's COB market modeling methodology in UE 308, UE 319, and UE 335. The primary concern is that PGE's methodology aggregates historic data in a manner that masks the value of COB market transactions. Staff testimony in UE 319 provides an illustrative example of how this occurs. An excerpt of this illustration is included as AWEC/202.

PGE has not provided evidence that the current methodology generates an accurate estimate of the benefits PGE obtains from the COB transactions. In a stipulation from Docket No. UE 335, PGE agreed to "continue to investigate methods to increase the granularity and improve the modeling of COB margins."[2/] However, PGE's opening testimony in this filing does not report on the methods investigated or the results of the investigation, and uses the same modeling approach it used in last year's AUT. PGE's investigation did not result in any

[1/] Docket No. UE 308, PGE/400, Niman - Peschka - Hager/9-10.
[2/] Docket No. UE 335, Order No. 18-405, Appen. A at 2 (Oct. 17, 2018).

substantial improvements to the COB model.[3/] An improved approach does exist, however, by using the three-year average of actual COB transaction values, and I recommend that PGE adopt this approach.[4/]

Q. IN YOUR SUMMARY FOR THIS ISSUE YOU MENTION THAT PGE CAN MAKE ECONOMIC TRANSACTIONS AT COB, AND THAT THESE TRANSACTIONS CAN REDUCE NVPC. PLEASE EXPLAIN HOW THIS WORKS.

A. Market prices at COB often differ from PGE's marginal cost of energy. When market prices at COB are higher than PGE's marginal cost, PGE can realize a net gain by selling energy at COB. When market prices at COB are lower than PGE's marginal cost, PGE can realize a net gain by purchasing energy at COB.

Q. WHAT DOES PGE USE TO MEASURE MARGINAL COST?

A. PGE generally uses Mid-C prices as a proxy for PGE's marginal cost. For example, PGE currently values COB transactions using the price difference between Mid-C and COB. In this filing PGE also proposes to use Mid C prices to value fourth quarter Boardman dispatches.[5/] My use of Mid C prices to value COB transactions is consistent with PGE's current and proposed practices.

Q. WHAT IS PGE'S HISTORIC COB TRANSACTION VALUE?

A. Confidential Table 2 provides PGE's historic COB transaction value when Mid-C prices are used as a proxy for the marginal cost of energy. I calculate this benefit with the following formula:

Benefit = Transaction MWh * (Mid-C Hourly Price – Transaction Price)

3/ AWEC/203 at 3 (PGE Response to AWEC Data Request 31).

4/ As discussed below, I recommend valuing actual COB transactions by multiplying the MWh by the actual Mid-C-COB market price margin. I recommend calculating the Mid-C-COB market price margin as the difference between the PowerDex Mid-C hourly market price index and the actual COB price.

5/ PGE/100, Niman – Kim – Batzler/24, line 10.

I use the PowerDex Mid-C Price Index as a measure for historic Mid-C hourly prices.

Confidential Table 2: COB Benefit Doubles Over Time

[redacted]

[redacted].

Q. YOUR TABLE SHOWS COB TRANSACTION VALUES ARE GROWING SUBSTANTIALLY. HAS PGE PROVIDED ANY EVIDENCE THAT THIS TREND WILL STOP IN 2019 OR 2020?

A. No. In fact, as solar penetration in California continues to climb, it is possible that COB transaction values will continue to grow. A simple linear trend forecast of COB transaction value predicts that 2020 benefit will be $[redacted].

Q. HOW DOES PGE'S FORECASTED COB TRANSACTION VALUE COMPARE TO HISTORIC TRANSACTION VALUES?

A. PGE forecasts a net benefit of $9 million.[6/] Using the same proxy for the marginal cost of energy as PGE, the lowest historic transaction value between 2015 and 2018 is $[redacted]. PGE's 3-year average transaction value is $[redacted]. PGE's 4-year average transaction value is $[redacted]. PGE's most recent COB transaction values for 2018 are $[redacted].

[6/] PGE/100, Niman – Kim – Batzler/17, line 5.

Therefore, PGE's forecast is $[redacted] lower than what is supported by the historic data.

Q. WHY IS PGE'S FORECASTED COB TRANSACTION VALUE SO MUCH LOWER THAN THAT SUPPORTED BY HISTORIC DATA?

A. PGE has created a complex model to incorporate forecasted Mid-C and COB market prices. Unfortunately, PGE's effort to incorporate forecasted market prices introduces substantial error in the COB benefit estimate. PGE's model uses three years of historic data. PGE aggregates historic data to the monthly level, and averages transactions across multiple years. As illustrated in AWEC/202, averaging and aggregating in this manner underestimates the value of transactions because transactions can take positive and negative values (for purchases and sales). PGE's model also limits transactions to either purchases or sales within any given aggregation period. As a result, PGE's model substantially underestimates volumes. PGE's model is also not forward-looking because it does not account for the large impact that California renewable penetration has had on COB transaction values.

Q. YOU STATED THAT PGE UNDER FORECASTS COB TRANSACTION VOLUMES. HOW DO HISTORIC TRANSACTION VOLUMES COMPARE TO PGE'S FORECAST OF TRANSACTION VOLUMES?

A. Like transaction value, transaction volumes have grown substantially. Confidential Table 3, below, provides transaction volumes from 2011 to present.

Confidential Table 3: COB MWh Transactions Triples Over Time

[redacted]

Total COB transactions have increased every year since 2011. A linear model of transaction volumes predicts 2020 volumes will reach [redacted]. PGE's model begins with a three-year average of transaction volumes of [redacted]. However, PGE's model only assigns value to [redacted], or 68 percent of the three-year average.

This highlights a fundamental flaw in PGE's volume forecast. PGE aggregates purchases and sales separately into monthly and hourly bins. For example, PGE adds all purchases in the first hour of every day in January into one bin, and all sales for the first hour of every day in a separate bin. Then when forecasting volumes, PGE selects only one of the bins for the forecast – purchases when the forecasted Mid-C-COB margin is positive and sales when the Mid-C-COB margin is negative. As a result, PGE's forecasted volumes will always be less than historic volumes.

Confidential Figure 1: Forecast COB Volumes Limited to One Bucket[7]

[redacted]

This is an important point that is worth reiterating. PGE forecasts a [redacted] [redacted] in COB volumes for 2020 relative to the three-year average. However, PGE does not forecast fewer COB transactions because PGE thinks there will be fewer opportunities to make economic transactions at COB. Rather, PGE forecasts fewer COB transactions because PGE's model aggregates and averages historic transactions in a manner that will always exclude one bucket of transactions. PGE's forecast model is mathematically incapable of forecasting COB transaction volume equal to or greater than historic transactions.

Q. WHAT WOULD PGE'S COB BENEFIT FORECAST BE IF 100 PERCENT OF THE THREE-YEAR AVERAGE OF TRANSACTIONS WERE VALUED USING PGE'S FORECASTED VALUE PER MWH TRANSACTION?

A. PGE forecasts an average value of $6 per COB transaction.[8/] Valuing all transactions at the average value would increase the COB benefit by [redacted], from $9 million to [redacted].

7/ Data for hour ending 12 A.M.
8/ Calculated from PGE/100 Niman – Kim – Batzler/17, lines 4 and 5.

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS COB MARGINS?

A. I recommend the Commission set the value of the COB benefit using the three-year average of actual COB transaction benefit, where the actual COB transaction benefit is valued using the PowerDex Mid-C hourly market index. PGE's 3-year average transaction value is [redacted]. Notably, this adjustment is conservatively low because it does not attempt to reflect the clear trend of [redacted]. This adjustment decreases NVPC by $7.1 million.

Q. WHY SHOULD THE COMMISSION SELECT YOUR MODEL OVER PGE'S MODEL?

A. My model is a simple, data-driven model that generates an unbiased estimate of COB transaction volumes and benefits. My model results in estimated transaction volumes and benefits that are consistent with historical volumes and benefits. PGE's model is a sprawling Excel workbook that performs numerous calculations, averages, scaling, shrinking, and otherwise manipulates historic data and forecasted price curves. PGE's model results in forecasted transaction volumes and COB margins that are not consistent with reality.

Q. PGE HAS PROPOSED INTRODUCING A TRANSMISSION DERATION FOR COB TRANSACTIONS. DOES YOUR RECOMMENDATION INCLUDE A TRANSMISSION DERATION?

A. No. Both PGE's COB benefit model and my COB benefit model rely on historic data, which already include transmission derations. PGE highlights a 2019 deration event to support the proposed change. However, this event will appear in the historic data and impact COB benefit forecasts for multiple years. Therefore, imposing an additional adjustment for transmission derations double-counts this effect.

III. ENERGY IMBALANCE MARKET: GREEN HOUSE GAS AWARDS

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE models Energy Imbalance Market ("EIM") benefits using one year of historic data from 2018. One component of historical EIM benefits is greenhouse gas ("GHG") awards. For the 2020 NVPC forecast, PGE reduces the historic GHG awards by 50 percent to account for changes in GHG bid rules. PGE's 50 percent reduction is due to its expectation that GHG award quantities will reduce by 50 percent. However, PGE fails to account for likely increases in the GHG prices. GHG prices are set through a competitive market, and a widely accepted economic phenomenon is that when supply is reduced, market prices increase. A 50 percent reduction in supply of GHG credit, therefore, will likely have a significant impact on GHG market prices. The change to GHG bid rules was implemented in November of 2018. When PGE files the 2020 November AUT update, PGE will have a full year, or nearly a full year, of post GHG EIM data. Rather than reducing GHG awards by 50%, I recommend that PGE update GHG awards to reflect the most recent 12 months of GHG data in its November update.

Q. WHY IS YOUR PROPOSAL AN IMPROVEMENT OVER PGE'S PROPOSED TREATMENT?

A. My proposal is purely data driven. PGE's proposal appears to be ad-hoc and does not account for the impact of new GHG bid rules on GHG prices.

IV. ENERGY IMBALANCE MARKET: MARKET LOSSES

Q. PLEASE SUMMARIZE THIS ISSUE.

A. Since PGE joined the EIM, it has incurred significant losses when participating in the EIM. While this could be attributed to the fact that PGE is a relatively new entrant in the EIM and must gain experience in this market, it is reasonable to expect that, as PGE gains this experience, it will incur fewer losses. Nevertheless, PGE's forecast of EIM benefits includes these historical losses. Further, PGE also attributes some of these losses to other factors, such as must-run obligations and fuel limitations, but these are already incorporated into MONET modeling. PGE's inclusion of these costs in EIM benefits, therefore, double-counts the impact of these limitations. I recommend excluding certain historic losses from the data used to forecast 2020 EIM benefits to account for PGE's EIM learning curve and to eliminate potential double counting.

Q. PLEASE EXPLAIN HOW PGE CALCULATES HISTORIC EIM BENEFIT.

A. PGE calculates EIM benefit as the difference between EIM settlements (payments to or from other EIM participants) and EIM-related dispatch costs. EIM dispatch costs is the EIM dispatch MWh multiplied by the monthly average variable cost per MWh for each unit.[9/] This is represented in the equation below:

EIM Benefit = EIM Settlement – (Incremental EIM MWh * Cost per MWh)

Q. PLEASE SUMMARIZE PGE'S 2018 EIM BENEFIT.

A. Confidential Table 4 below reproduces PGE's summary table for 2018 EIM Benefit calculations.

Confidential Table 4: 2018 Monthly EIM Benefits and Losses

[redacted]

9/ It is not clear how Mid-C or Pelton Round Butte EIM costs are calculated. The data provided in response to AWEC DR 35 for these facilities are not consistent with PGE's MFR workpapers for EIM costs. AWEC is continuing to investigate this issue.

[redacted].

Q. WHY DOES PGE EXPERIENCE LOSSES IN THE EIM?

A. PGE experiences losses because PGE’s EIM bids do not reflect the marginal cost of dispatching generation. According to economic theory, PGE would maximize benefit by bidding into the EIM market at the marginal dispatch cost of each unit. In actual operations, there are several factors that may prevent PGE from bidding at marginal cost:

- Many factors impact the marginal cost of dispatching generation, and PGE may not have accurate estimates of marginal cost when submitting bids.
- PGE may bid above or below marginal cost to achieve operational goals.
- PGE may experience unexpected outages after bids are submitted.

Q. PLEASE EXPLAIN WHY PGE MAY NOT HAVE ACCURATE ESTIMATES OF MARGINAL COST WHEN SUBMITTING BIDS.

A. In general, the dispatch cost for thermal plants is a function of heat rate (fuel efficiency of the plant) and fuel cost. The heat rate of a plant can be influenced by dispatch rate, weather, and maintenance condition. These factors change often, and this can cause PGE to have inaccurate estimates of marginal cost when submitting bids.

Q. PLEASE EXPLAIN WHY PGE MAY BID ABOVE OR BELOW MARGINAL COST TO ACHIEVE OPERATIONAL GOALS.

A. In response to AWEC Data Request (“DR”) 35, PGE identifies the following three factors that may impact EIM bids:

- opportunity costs (i.e., ability to trade in other markets or at other times);
- must-run events (i.e., a need to operate a plant no matter the price offered in the market);

- use limits (i.e., a need to communicate to the market via a price signal that the resource is energy or fuel limited).[10]

Q. HOW DO UNEXPECTED OUTAGES AFFECT EIM BENEFITS?

A. PGE calculates benefits in the fifteen-minute market, real time dispatch, and uninstructed imbalance energy. The fifteen-minute market and real-time-dispatch benefits correspond with bid-related dispatch optimization and are part of planned EIM instructions. The uninstructed imbalance energy is related to differences between CAISO's EIM dispatch instructions and actual dispatch. Unexpected outages and associated EIM losses are realized in the calculations for uninstructed imbalance energy.

Q. IS THERE REASON TO BELIEVE THAT PGE WILL EXPERIENCE FEWER EIM LOSSES IN 2020 THAN IN 2018?

A. There is reason to believe that PGE will experience fewer EIM losses for the fifteen-minute market and real time dispatch as PGE gains experience in the EIM market. 2018 was PGE's first full year of participation in EIM. For example, PGE admits that Boardman will experience fewer EIM losses in 2020 due to modeling improvements.[11]

Q. IS IT APPROPRIATE FOR PGE TO INCLUDE LOSSES RELATED TO OPERATIONAL OBJECTIVES, LIKE OPPORTUNITY COSTS, MUST-RUN EVENTS, AND USE LIMITS, WHEN CALCULATING EIM BENEFITS?

A. No, this may result in double counting the impact of such objectives. The appropriate place to model operational objectives is within the MONET model. For example, PGE's filing includes fuel-related restrictions for Boardman. Including costs associated with Boardman coal shortage in both the EIM benefit calculation and the MONET model will double count the impact of this shortage.

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[10] AWEC/203 at 6 (PGE Response to AWEC DR 35).
[11] Id. at 7 (PGE Response to AWEC DR 35, part e).

Q. WHAT IS YOUR RECOMMENDATION FOR 2020 EIM BENEFIT CALCULATIONS?

A. I recommend the 2020 EIM benefit forecast be improved to account for PGE learning and to remove the double counting of operational objectives. This is accomplished by removing loss-generating transactions from the 2018 EIM data for the fifteen-minute market and real-time-dispatch. I recommend retaining losses associated with uninstructed imbalance energy to reflect losses associated with unexpected outages. This recommendation reduces NVPC by $8.8 million.[12/]

My recommendation is conservative because it does not replace losses with gains. In actual operations, as PGE gains experience, historic losses may be replaced by gains. My recommendation is also conservative because I retain all losses associated with uninstructed imbalance energy. I retain these losses to reflect unexpected outages. However, a portion of uninstructed imbalance energy loss may be due to incorrect market bids or operational objectives. PGE should continue to improve its modeling of EIM benefits in future AUTs to account for these issues.

V. QUALIFYING FACILITIES

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE states that QF costs increase PGE's NVPC forecast for 2020 by $65.8 million.[13/] PGE has over-forecast QF generation in recent AUTs. PGE proposes to true-up QF volume variances related to commercial operating dates ("COD"). PGE's proposal will likely result in

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12/ This value includes approximate calculations for PGE hydro facilities from January to April. This is due to limitations in calculating costs for hydro facilities with the available data. AWEC is continuing to invest this issue.

13/ PGE/100 Niman – Kim – Batzler /24, footnote 20.

a substantial intergenerational transfer. PGE should reduce the forecasted QF quantity in 2020 NVPC to account for expected COD. If the Commission adopts my proposed changes to QF forecast method, I recommend that the Commission not adopt the true-up model proposed by PGE. If the Commission does not adopt my QF forecast method, PGE will likely over-forecast QF and a true up mechanism will protect customers. I propose a modification to the true-up mechanism if it is adopted.

Q. WHAT EVIDENCE IS THERE THAT PGE OVER-FORECASTS QF QUANTITIES?

A. Prior to 2017 PGE had reasonably accurate QF forecasts, largely because it had very few QFs. However, in 2017 and 2018, actual QF generation was [redacted] percent and [redacted] percent of forecasted generation, respectively. In UE 335 PGE acknowledged that actual commercial operation data was an important factor in forecasting QF energy, and that actual COD can differ from contract COD date.[14]

Q. HOW DOES PGE PROPOSE TO ADDRESS OVER-FORECASTING QF VOLUMES?

A. PGE proposes to continue historic COD forecast methods, and to defer the NVPC differences caused by actual COD differing from forecasted COD.

Q. WHAT CONCERNS DO YOU HAVE WITH PGE'S PROPOSAL?

A. I have three concerns with PGE's proposal. First, given the large impact of QFs on rates, 2020 rates should include the most accurate forecast of QF volumes as possible. Second, if the forecast bias for QF volumes is removed, there is no need to true up COD dates. Third, if the Commission confirms PGE's proposed true-up, the true-up mechanism should be refined to account for actual retail energy sales.

[14] Docket No. UE 335, PGE/300 at 32-33.

Q. HOW DO YOU PROPOSE TO IMPROVE PGE'S FORECAST OF COD DATES?

A. I recommend that PGE adopt the approach used by PacifiCorp in PacifiCorp's NVPC forecast. In Docket No. UE 323, Oregon Citizens' Utility Board ("CUB") proposed a contract delay rate methodology calculated using a three-year average of historic contract delays. PGE argued against the contract delay rate method in UE 335, arguing that PGE did not have enough QF experience to implement a contract delay rate.[15/] However, with 2018 and 2019 QF additions, PGE now has enough experience to implement this method.

Q. WHY DO YOU RECOMMEND ELIMINATING THE COD TRUE-UP?

A. PGE already has a NVPC deferral process implemented within the Power Cost Adjustment Mechanism ("PCAM"). The PCAM allows PGE to defer excess costs and revenues, and can effectively address actual COD variance, if the initial forecast is unbiased. There is no need for an additional deferral.

Q. PGE HAS A LEGAL REQUIREMENT TO PURCHASE QF POWER. IS IT FAIR TO SHIFT SOME OF THE RISK OF COD VARIANCE TO PGE?

A. Yes. While PGE has a federal obligation to purchase QF power, it does have some control over the number of QFs that seek to sell power to PGE. The primary driver of the large number of QFs on PGE's system in recent years is PGE's renewable resource deficiency date. PGE's decisions in its Integrated Resource Planning ("IRP") process have resulted in this date coming sooner than it should. In its 2016 IRP, PGE determined that it would be physically RPS short (meaning its owned and contracted RPS resources would be insufficient on their own to meet RPS needs) in 2025 and used this to help justify its decision to procure a new renewable resource well ahead of need. As AWEC noted in comments, PGE could have demonstrated that

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15/ Docket No. UE 335, PGE/1400 at 42.

it had no need for a new RPS resource until 2037, had it assumed that it would procure unbundled RECs and use its REC bank. PGE resisted these recommendations, however, and as one consequence, the Commission adopted a 2025 renewable resource deficiency date following the 2016 IRP on September 18, 2017.[16/] PGE's on-peak renewable avoided cost for a solar QF jumped from $36.16 in 2024 to $103.83 in 2025, and PGE has included at least 49 QF contracts in the AUT that were executed on or after these avoided costs were established. PGE's own resource decisions, therefore, have significantly impacted the amount of QF activity it has seen recently, and PGE should accordingly bear some risk associated with these QFs.

Q. WHAT CHANGES DO YOU PROPOSE TO PGE'S TRUE UP, IF THE COMMISSION CHOOSES TO INCLUDE BOTH THE PCAM DEFERRAL AND THE COD DEFERRAL?

A. PGE's proposal does not fully true up COD, because it does not account for differences in load. To fully adjust for differences between forecast and actual COD, PGE needs to calculate the amounts collected from customers. To do this, PGE should add the following steps to the end of the true up process:

1) Calculate the NVPC rate difference resulting from actual CODs.

2) Multiply the NVPC rate difference by actual billing determinants for 2020.

VI. BOARDMAN SUPPLY CONSTRAINTS

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE anticipates a coal and Trona supply constraint in 2020. Due to this constraint, Boardman cannot economically dispatch in 2019 Q1 and Q3. PGE addresses this limitation by derating

[16/] Docket UM 1728, PGE's Revised Application to Update Schedule 201 Qualifying Facility Information (Sept. 14, 2017).

Boardman within constrained months by a fixed amount. I have several concerns with PGE's proposal.

1. PGE implements the coal deration first, and the Trona deration second. This results in excess coal availability in September and the September derate is not necessary.
2. PGE calculated coal and Trona shortages assuming Boardman runs at full capacity when not in an outage state. In reality, and in MONET, Boardman runs below the maximum capacity. This means that the derate percentage is higher than necessary. PGE uses MONET results from the previous step as the base fuel requirements. This will account for economic dispatching within MONET.
3. In actual operations, PGE is more likely to address coal shortages by running at minimum operating capacity or through a full plant shutdown. PGE should model plants as fully available within the month, but with days of 100 percent outage at the end of each month enough to address coal limits.
4. PGE should shut down Boardman for parts of 2019 to build fuel stockpiles and reflect the likelihood that Boardman will be less economical in parts of 2019 than in January and February of 2020. PGE should update the MONET derate needs in the November update to reflect expected January 2020 fuel supplies.

Q. YOU ARE CONCERNED THAT PGE IMPLEMENTS TRONA DERATING AFTER COAL DERATING. WHY IS THIS A CONCERN?

A. PGE limits the dispatch of Boardman in March 2020 to account for Trona and in September 2020 to account for coal shortages. However, the coal shortage in September is forecast before the Trona derate is implemented. If PGE had implemented the Trona derate prior to the September coal shortage calculation, PGE would not find a coal shortage in September.

Q. HOW DO YOU RECOMMEND THIS ISSUE BE CORRECTED?

A. PGE has determined that March is the most economic month to implement Trona related shortages.[17/] PGE should move coal derates prior to March as necessary to operate until March. PGE should then calculate the Trona derate required in March absent the September derate. PGE should then test to see if any additional fuel related derates are necessary on or after March.

Q. HOW DOES PGE CALCULATE THE SUPPLY SHORTAGE DERATE PERCENT?

A. PGE calculates the supply shortage derate by first identifying the supply needs if Boardman operates at full capacity when not experiencing an outage. However, Boardman does not operate at full capacity absent supply shortages, because Boardman is dispatched economically. Absent a supply shortage PGE will ramp Boardman up and down based on market conditions. PGE overestimates the magnitude of the shortage, and thus applies too great a supply-related derate.

Q. HOW DO YOU RECOMMEND PGE CALCULATE THE DERATE PERCENT?

A. PGE should calculate the derate using Boardman's MONET energy output from the step prior to the derate. This provides a more accurate picture of the supply shortage. The fuel derate steps should be performed last, to reflect all other input updates.

Q. HOW DOES A PERCENTAGE DERATE IMPACT MONET MODELING?

A. A percentage derate has the same effect as reducing the capacity of a plant. This constrains the operating range of the plant to a level that is not realistic and not representative of actual operations. For example, PGE models a March derate of 64 percent for Boardman. This means that during March, Boardman will never operate at higher than 64 percent of capacity. In actual

17/ PGE/100 Niman – Kim – Batzler /21 lines 11 to 14 and footnote 17.

operations PGE addresses supply constraints by shutting down the plant.[18] This allows PGE to take full advantage of Boardman's flexibility.

Q. HOW DO YOU RECOMMEND PGE MODEL BOARDMAN'S FUEL CONSTRAINT?

A. I recommend that PGE model 100 percent derates for enough hours within the month to satisfy supply constraints. I further recommend that, to the extent possible given minimum cycle times, PGE condense these hours in periods with low market prices.

Q. WHAT DO YOU RECOMMEND PGE DO IN 2019 TO REMEDY THE COAL SHORTAGE?

A. PGE can perform reserve shutdowns in 2019 during shoulder months to help build the fuel stockpile going into 2020. PGE should perform reserve shutdowns in 2019 until the opportunity cost of shutting down in 2019 equals the forecasted opportunity cost of shutting down in January and February of 2020. This approach will minimize the total cost of the shortage. PGE can update the supply shortage in the November 2019 AUT update to account for 2019 shutdowns.

Q. HOW SHOULD THE COMMISSION SET 2020 RATES IF PGE FAILS TO BALANCE THE 2019 COST OF THE COAL SHORTAGE WITH THE 2020 COST OF THE COAL SHORTAGE?

A. The Commission should set rates as if PGE had balanced the marginal cost of reserve shutdowns in 2019 and 2020.

VII. BOARDMAN END OF OPERATIONS

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE must stop coal-fired operations at Boardman by January 1, 2021. In this filing PGE stops Boardman operations after September 2020. PGE stops operations early to mitigate the

[18] AWEC/203 at 1 (PGE Response to AWEC DR 003).

potential cost of removing coal from Boardman. However, PGE does plan to operate Boardman in Q4, 2020 if there is enough coal. I have the following concern with PGE's proposal:

1. MONET should be allowed to burn coal, if coal is available in October. PGE's filed model consumes less coal than available, and Boardman will have coal available to burn in October.

Q. HOW DOES PGE MODEL BOARDMAN'S CLOSURE IN MONET?

A. PGE assigns Boardman a 100 percent derate in October through December of 2020. This means that Boardman does not operate in MONET in October 2020.

Q. WHY DOES PGE PREVENT BOARDMAN FROM OPERATING IN OCTOBER 2020?

A. PGE's primary concern is that no fuel be left on the ground after December 31, 2020. Boardman can burn over [redacted] tons of coal in Q4, 2020. However, PGE is concerned that a prolonged outage in Q4 could prevent Boardman from operating. If PGE enters Q4 with a large coal pile, and experiences a prolonged outage, PGE may face additional decommissioning costs associated with coal removal.[19]

Q. COULD PGE ALLOW BOARDMAN TO OPERATE IN Q4 IN MONET WITHOUT INCREASING THE RISK OF HAVING TO REMOVE COAL IN 2021?

A. Yes. PGE's goal would be accomplished more effectively by limiting coal deliveries in Q4 but continuing to model operations until all Boardman coal is consumed. PGE's filed model consumes less coal than available. This means that if PGE operated consistently with the AUT filing, PGE will have a substantial coal pile in October 2020.

[19] AWEC/203 at 2 (PGE Response to AWEC DR 009).

Q. HOW DO YOU KNOW THAT PGE'S MODEL RESULTS IN A SUBSTANTIAL COAL PILE IN OCTOBER 2020?

A. Confidential Table 5 below illustrates PGE's forecasted January 2020 coal stockpile, monthly coal deliveries, and monthly coal burn. Under PGE's model [redacted] tons remain unburned after Boardman closes.

Confidential Table 5: Coal Remains After Boardman Shuts Down

[redacted]

Q. HOW COULD PGE'S MODEL BE ADJUSTED TO BURN ALL COAL AVAILABLE IN 2020?

A. As a last step in the model runs, PGE could calculate total coal available in 2020, and reduce the Q4 derations to allow this coal to be consumed in 2020.

VIII. SHORT-TERM DIRECT ACCESS LOADS

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE includes short-term direct access loads as cost-of-service loads when forecasting NVPC. However, short-term direct access loads commit to market-based rates for at least one year and can reasonably be excluded from the NVPC calculations. Short-term direct access elections are made in November. I recommend that in PGE's final November update, the NVPC load forecast be updated to exclude short-term direct access loads.

Q. PLEASE EXPLAIN WHY DIRECT ACCESS LOADS SHOULD BE EXCLUDED FROM NVPC.

A. NVPC represents a forecast of the cost for PGE to serve load. Direct access customers receive distribution service from PGE but acquire energy from third parties. PGE is unlikely to provide energy service to direct access customers in 2020. Therefore, for an accurate NVPC forecast, PGE should exclude these loads from the load forecast.

Q. DOES PGE EXCLUDE ANY DIRECT ACCESS LOADS?

A. Yes, PGE excludes long-term direct access load. However, PGE does not exclude short-term direct access load.

Q. WHAT IS THE DIFFERENCE BETWEEN SHORT- AND LONG-TERM DIRECT ACCESS?

A. Long-term direct access customers have opted out of cost-of-service rates, and PGE is not obligated to plan for such load when it makes capital investments. However, short-term direct access customers have the option of returning to cost-of-service rates in subsequent years. Because of this, PGE is obligated to include short-term direct access loads when planning capital investments. Long-term planning though the IRP process, however, is not relevant to PGE's annual forecast of NVPC.

Q. HOW DO YOU RECOMMEND SHORT TERM DIRECT ACCESS LOADS BE TREATED?

A. I recommend that short-term direct access loads be excluded from the load forecast for the November NVPC update.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

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OF OREGON

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In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
2020 Annual Power Cost Update (Schedule 125).	)
	)

EXHIBIT AWEC/201

QUALIFICATIONS OF LANCE D. KAUFMAN

CURRICULUM VITAE

LANCE KAUFMAN
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EDUCATION:

University of Oregon	Ph.D.	Economics	2008 – 2013
University of Oregon	M.S.	Economics	2006 – 2008
University of Anchorage Alaska	B.B.A.	Economics	2001 – 2004

CERTIFICATIONS:

Certified Depreciation Professional	Society of Depreciation Professionals	2018

PROFESSIONAL EXPERIENCE:

Principal Economist	Aegis Insight	2014 – Present
Senior Economist	Oregon Public Utility Commission	2015 – 2018
Public Utility Advocate	Alaska Department of Law	2014 – 2015
Senior Economist	Oregon Public Utility Commission	2013 – 2014
Instructor	University of Oregon	2008 – 2012
Research Assistant	University of Alaska Anchorage	2003 – 2008

PROFESSIONAL MEMBERSHIPS:

Society of Depreciation Professionals	2015 – Present
American Economics Association	2017 – Present

RESEARCH, CONSULTING, AND ECONOMETRIC ANALYSIS:

- Davison Van Cleve, PC, Salem, OR 2019
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net variable power cost calculations in PORTLAND GENERAL ELECTRIC COMPANY, 2020 Annual Power Cost Update Tariff Public Utility Commission of Oregon Docket No. UE 359.
- Sanger Law, PC, Salem, OR, 2019
  Retained as an expert witness for Renewable Energy Coalition and Rocky Mountain Coalition for Renewable Energy regarding Qualified Facility avoided costs in Application of Rocky Mountain Power for a Modification of Avoided Cost Methodology and Reduced Term of PURPA Power Purchase Agreements Public Service Commission of Wyoming Docket No. 20000-545-ET-18
- Sanger Law, PC, Salem, OR, 2019
  Retained as an expert witness for Cafeto Coffee Company regarding the necessity, design, and location of transmission lines in SPRINGFIELD UTILITY BOARD Petition

for Certificate of Public Convenience and Necessity Public Utility Commission of Oregon Docket No. PCN 3.

- Baumgartner Law, LLC, Denver, CO, 2018
  Retained as an expert witness for plaintiffs re calculation of economic harm due to injury in re Eric Bowman, v. Top Tier Colorado, LLC,, Case No. 18CV31359, United States District Court, District of Colorado.
- Cohen Milstein Sellers & Toll PLLC, Washington DC, 2018
  Retained as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Isaac Harris et al. v. Medical Transportation Management, Inc., Civil Action No. 17-1371, United States District Court, District of Columbia.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2018
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Vicky Maldonado and Carter v. Apple Inc., AppleCare Services Company, Inc., and Apple CSC, Inc., Case No. 3:16-cv-04067-WHO, United States District Court, District of California.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2018
  Deposed and testified as an expert witness for plaintiffs re calculation of unpaid mileage for truck drivers in re Swift Transportation Co., Inc., Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re reasonable attorney fees in re Jeanne Stroup and Ruben Lee, v. United Airlines, Inc., Case No. 15-cv-01389-WYD-STV, United States District Court, District of Colorado.
- Klein and Frank, PC, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re potential jury bias in re Gail Goehrig and Chris Goehrig v. Core Mountain Enterprises, LLC, Case No. 2016CV030004, San Juan County District Court.
- Robert Belluso, Pennsylvania, 2017
  Retained as expert witness for plaintiff re lost profit in re Robert Belluso D.O. v Trustees of Charleroi Community Park, PHRC Case No. 201505365, Pennsylvania Human Relations Commission.
- Lowery Parady, LLC, Denver, Colorado, 2017
  Analyzed payroll data and calculated unpaid overtime and unpaid hours for plaintiff class action in re Violeta Solis, et al. v. The Circle Group, LLC, et al., Case No. 1:16-cv-01329-RBJ, United States District Court, District of Colorado.
- Sawaya & Miller Law Firm, Denver, Colorado, 2017
  Provided data processing and analysis of employment records.
- Financial Scholars Group, Orinda, California, 2017
  Provided analysis of risk profile in bundled real estate and personal loans in re Old Republic Insurance Company v. Countrywide Bank et al., Circuit Court of Cook County, Illinois, Chancery Division.
- Financial Scholars Group, Orinda, California, 2017
  Provided consultation and analysis of financial market transactions in preparation of settlement claims filings in re Laydon v. Mizuho Bank, Ltd., et al. and Sonterra Capital Master Fund Ltd., et al v. UBS AG et al.

- Clean Energy Action, Boulder, Colorado, 2016 – 2017
  Provided consultation on the appropriate discounting methodology used in energy resource planning in the Public Service Company of Colorado application for approval of the 2016 Electric Resource Plan, Proceeding No. 16A-0396E, Public Utilities Commission of the State of Colorado.
- Confidential Client, 2016
  Provided analysis and report on the probability that distinct crimes are independent events based on geographical analysis of crime rates.
- Christine Lamb and Kevin James Burns, Denver, Colorado, 2016
  Provided data analysis for defendant of the impact of ethnicity on termination decisions in re Aragon et al v. Home Depot USA, Inc., Case No. 1:15-cv- 00466-MCA-KK, United States District Court, District of New Mexico.
- Steptoe & Johnson LLP, Washington, DC, 2015 – 2016
  Programmed analysis of internet traffic data for plaintiffs applying a proprietary probability model developed to identify and verify accounts responsible for repeated infringements of asserted copyrights by defendants' internet subscribers in re BMG Rights Management (US) LLC, and Round Hill Music LP v. Cox Enterprises, Inc., et al., Case No. 1:14-cv-1611(LOG/JFA), United States District Court Eastern District of Virginia, Alexandria Division.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2014 –
  Programmed analysis for plaintiffs to calculate unpaid mileage for truck drivers in re Swift Transportation Co., Inc., Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Padilla & Padilla, PLLC, Denver, Colorado, 2014 – 2016
  Provided research and analysis for plaintiffs re the impact on minority applicants from use of the AccuPlacer Test by the City and County of Denver, and estimated damages in re Marian G. Kerner et al. v. City and County of Denver, Civil Action No. 11-cv-00256-MSK-KMT, United States District Court, District of Colorado.
- U.S. Equal Employment Opportunity Commission, 2013 –
  Provided statistical analysis of EEOC filings.

REGULATORY PROCEEDINGS:

- Portland General Electric 2016 Annual Power Cost Variance Docket No. UE 329.
- PacifiCorp 2016 Power Cost Adjustment Mechanism Docket No. UE 327.
- Public Utility Commission of Oregon Staff Investigation into the Treatment of New Facility Direct Access Charges Docket No. UM 1837
- PacifiCorp Oregon Specific Cost Allocation Investigation Docket No. UM 1824.
- PacifiCorp 2018 Transition Adjustment Mechanism Docket No. UE 323.
- Portland General Electric 2018 General Rate Case Docket No. UE 319.
- Avista Corp. 2017 General Rate Case Docket No. UG 325.
- Portland General Electric Affiliated Interest Agreement with Portland General Gas Supply Docket No. UI 376.
- Portland General Electric 2017 Automated Update Tariff Docket No. UE 308
- PacifiCorp 2017 Transition Adjustment Mechanism Docket No. UE 307

- Portland General Electric 2017 Reauthorization of Decoupling Adjustment Docket No. UE 306
- Northwest Natural Gas Investigation of WARM Program Docket No. UM 1750.
- PacifiCorp Investigation into Multi-Jurisdictional Allocation Issues Docket No. UM 1050.
- Idaho Power Company 2015 Power Supply Expense True Up Docket No. UE 305
- Homer Electric Association 2015 Depreciation Study U-15-094
- Submitted prefiled testimony regarding the depreciation study.
- Chugach Electric Association 2015 Rate Case U-15-081
- Developed staff position regarding margin calculations.
- ENSTAR 2014 Rate Case U-14-111
- Submitted prefiled testimony regarding sales forecast.
- Alaska Pacific Environmental Services 2014 Rate Case U-14-114/115/116/117/118
  Submitted prefiled testimony regarding cost allocations, cost of service, cost of capital, affiliated interests, and depreciation.
- Alaska Waste 2014 Rate Case U-14-104/105/106/107
  Submitted prefiled testimony regarding cost of service study, cost of capital, operating ratio, and affiliated interest real estate contracts.
- Fairbanks Natural Gas 2014 Rate Case U-14-102
  Submitted prefiled testimony regarding cost of service study and forecasting models.
- Avista 2015 Rate Case U-14-104
  Submitted analysis supporting OPUC Staff settlement positions regarding Avista's sales and load forecast, decoupling mechanisms and interstate cost allocation methodology. Represented Staff in settlement conferences on November 21, November 26, and December 4, 2013.
- Portland General Electric 2015 Rate Case
  Submitted pre-filed opening testimony addressing PGE's sales forecast, printing and mailing budget forecast, mailing budget, marginal cost study, line extension policy and reactive demand charge. Represented OPUC Staff in settlement conferences on May 20, May 27, and June 12, 2014.
- Portland General Electric 2014 General Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PGE's sales and load forecast, revenue decoupling mechanism, and cost of service study. Represented OPUC Staff in settlement conferences on May 29, June 3, June 6, July 2, and July 9 of 2013. Submitted testimony in support of partial stipulation, pre-filed opening testimony addressing PGE's decoupling mechanism, and testimony in support of a second partial stipulation.
- PacifiCorp 2014 General Electric Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PacifiCorp's sales and load forecast and cost of service study. Represented Staff in settlement conferences on June 12 through June 14, 2013.

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EXHIBIT AWEC/202

ILLUSTRATION FROM UE 319 STAFF TESTIMONY

[redacted] **[END CONFIDENTIAL]** One consequence is that customers receive no value for economic COB purchases. A second consequence is that customers receive substantially less value from sales at COB than the company actually achieves.

Q. You mention that PGE's method provides no value for purchases at COB. Is it normal for PGE both buy and sell at COB in the same month?

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

Q. Please provide an illustrative example using simplified numbers that demonstrates why PGE might make both purchases and sales at COB even if the average margin is positive.

A. Assume that in one month there are 15 days where the Mid-C price is $30 per MWh and the COB price is $20 per MWh. This results in a COB margin of minus $10 ($20 - $30 = - $10). Assume on the other 15 days that the Mid-C

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[6] *See* Exhibit 204. In this figure, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[7] *See* Exhibit 205, Analysis of On Peak COB Transactions.

[8] *See* Exhibit 204 which shows positive and negative margins within the same day. In hours 2 and 8 the margin favors Mid-C sufficiently for PGE to purchase at COB rather than sell.

price is $45 per MWh and the COB price is $15 per MWh. This results in a COB margin of $30 per MWh ($45 - $15 = $30). In this hypothetical scenario, there are 15 days where the margin at COB is minus $10 and 15 days where the margin at COB is plus $30. The average margin is $10 per month (15 x (-10) + 15 x 30)/30 = $10). However, even though the monthly average is positive representing an incremental margin at COB, it is economically better to sell at COB half the days in the month and economically better to buy at COB the other half.

The important point is that the Company can realize an incremental benefit on both purchases and sales, within the same month, by arbitraging between the appropriate markets. PGE will likely have profitable 2018 purchases at COB even though the COB forecast price is higher than the Mid-C forecast price. Therefore, excluding normal COB purchases from the valuation of the COB transactions is inappropriate.

Q. Can you give a simple numeric example that compares the Company's proposed treatment with the Company's actual trading pattern?

A. Yes, consider the scenario presented in the Q&A above, where there are 15 days in the month with a negative margin of ($10) per MWh, 15 days in the month with a positive margin of $30 per MWh, and the average margin is $10 per month. Suppose further that there is 1 MWh of transmission available in every day. The table below summarizes the "actual" operations that would minimize power cost.

Table 1 Hypothetical Example of COB Value Using Staff Method

Margin	Transaction	MWh	Profit
-10	Purchase at COB	15	$150
30	Sell at COB	15	$450
		Total Profit	**$600**

Using actual margins, and actual MWh, the total profit is $600. PGE's modeling approach to COB transactions for this example would result in the following estimate.

Table 2 Hypothetical Example of COB Value Using PGE Method

Avg. Margin	Transaction	MWh	Profit
10	Sell at COB	15	$150
		Total Profit	$150

Using monthly average margin and actual MWh results in a total profit of only $150, much less than the actual profit.

Q. Is it possible to compare the Company's proposed approach against the Company's actual transactions?

A. Yes. Similar to the example above, we can use actual data, and compare same two approaches:

- Actual Margin times Actual MWh; and
- Monthly Average Margin times Actual COB sales.

Staff calculated the company's actual COB trading margin for 2014, 2015, and 2016 using the Company's actual transactions and an hourly Mid-C price index. Staff then calculated the value of the Company's actual COB

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PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
2020 Annual Power Cost Update (Schedule 125).	)
	)

EXHIBIT AWEC/203

COMPANY RESPONSES TO DATA REQUESTS

May 29, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to AWEC Data Request No. 003
Dated May 15, 2019

Request:

Please refer to PGE/100, Niman – Kim – Batzler / 18, lines 17-18. Did PGE consider derating Boardman in 2019 in order to rebuild coal inventories prior to 2020? If no, why not? If yes, provide the dates and derating amount.

Response:

Yes, PGE has derated Boardman in both 2018 and 2019 in order to save coal inventories for years 2019 and 2020, respectively.

In order to save coal inventories for the first part of 2019, which is typically the coldest part of the year, PGE ceased Boardman operations beginning October 20, 2018 through the morning of November 18, 2018. Boardman remained offline during this period even during times the plant would have been economic to run, as market prices exceeded Boardman's dispatch costs.

PGE also ceased Boardman operations beginning March 15, 2019 and plans to keep the plant offline through early July. During this period there are times when Boardman would have been economic to operate as market prices exceeded Boardman's dispatch costs. This action was undertaken to save coal for December 2019 and January 2020.

May 29, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to AWEC Data Request No. 009
Dated May 15, 2019

Request:

Please refer to PGE/100, Niman – Kim – Batzler / 23, lines 20-21.

a. **Does PGE agree that given the $37.50 per ton removal cost Boardman will be economic to dispatch at negative market prices in Q4 2020? If no, why not?**

b. **What factors or events would lead to coal remaining on site after September 2020?**

Response:

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

   If there is coal remaining on site in Q4 of 2020, the cost of removal will be factored into plant dispatch decisions. Therefore, it may be economic to run the plant even when market prices are negative so long as the plant dispatch cost, less the cost of removal, is below market. However, market prices are not the main consideration as to why September 2020 was selected as the last month of planned operation. This date was selected in the event the plant has an unplanned outage during the period between Q1 and Q3 2020 which could prevent the plant from consuming coal. In that event, Q4 of 2020 could provide PGE with an opportunity to consume any remaining coal rather than incurring greater decommissioning costs associated with coal removal.

b. The main factor that could lead to coal remaining on site after September 2020 would be an unplanned outage preventing Boardman from consuming coal.

June 19, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Jay Tinker
Director, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to AWEC Data Request No. 031
Dated June 5, 2019

Request:

Please refer to PGE/100, Kiman-Kim-Batzler/14 [SIC], lines 12 to 14.

a. **Please provide all workpapers and communications related to the continued investigation of granularity and improved modeling of COB margins.**

b. **Please provide PGE's conclusions related to this investigation and explain how PGE arrived at these conclusions**.

Response:

PGE is objecting to this request on the basis that it is overly broad and unduly burdensome. Subject and without waiving this objection PGE replies as follow:

a. Attachment 031-A provides work papers and communication related to PGE's investigation into increasing the granularity to improve the modeling of COB margins.

b. PGE concluded that increasing the granularity to an hourly / weekly forecast would be overly burdensome, prone to errors, and does not provide a significant improvement, if any, to the modeling of COB trading margins. As such PGE continued to use the COB trading margin method from its 2019 general rate case (UE 335).

Attachment 031-A is protected information subject to Protective Order No. 19-112.

June 20, 2019

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Jay Tinker
Director, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to AWEC Confidential Data Request No. 035
Dated June 6, 2019

Request:

Please refer to the MFR workpaper "#EIM Benefit_Workpaper_Sub-Hour Dispatch_CONF.xlsx."

a. **Please provide this data at the most granular level available.**
b. **Please provide the source for the data in sheet "Power Cost Unit Summary." Please include transaction-level accounting data if the data represents historic costs. Please include an explanation for why these values represent incremental dispatch cost associated with EIM increments and decrements.**
c. **Suppose that CAISO schedules a generation decrement in the 15-minute market ("FMM") (i.e., a reduction from the base schedule) and that PGE experiences a loss for that unit. Please provide an explanation for the factors that would lead to such a loss.**
d. **Please explain why EIM bids above or below operating costs may be reasonable and prudent operations.**
e. **Please confirm that at the June 4, 2019 workshop PGE indicated that it expects [Begin Confidential] Boardman to experience fewer losses in future operations relative to historic operations [End Confidential].**
f. **For each month and unit in 2018 where the EIM loss exceeds $5 per net incremental MWh, please provide an explanation for why PGE experienced this loss and whether PGE intends to continue experiencing these losses in the future.**
g. **Is it reasonable to expect that as PGE becomes more experienced with the EIM market, PGE will experience fewer plant-month EIM losses in 2020? If no, why not?**

Response:

a. Attachment 035-A provides data for each resource (i.e., labeled "PositionName" in the workpaper).

Attachment 035-A is protected information subject to Protective Order No 19-112.

In Attachment 035-A the detail for thermal resources includes:[1]

1. Base Schedule (MWh)
2. Fifteen Minute Market (FMM) Incr (MWh)
3. Real Time Dispatch (RTD) Incr (MWh)
4. Uninstructed Imbalance Energy (UIE) Incr (MWh)
5. FMM EN Rev
6. RTD EN Rev
7. RTD UIE Rev
8. Bid Cost Recovery (BCR)

In Attachment 035-A, the detail for hydro resources includes:[2]

1. Base Schedule (MWh)
2. FMM Incr (MWh)
3. RTD Incr (MWh)
4. UIE Incr (MWh)
5. FMM EN Rev
6. RTD EN Rev
7. UIE Rev
8. BCR
9. Cost
10. P&L (Profit and Loss)

Throughout the year, PGE completed its benefit measurements on a quarterly basis after CAISO's T+12 settlement activity was complete for the relevant trading months (i.e., 12 business days after the relevant months). Since that time, additional settlement activity has been processed (e.g., T+55 settlement activity, which would be 55 business days from the relevant months) and because the results reported in Attachment 035-A reflect additional settlement activity, they will not necessarily match the summaries reported in the above referenced work paper. The most notable changes for thermal resources are during the months of September and November.

With respect to hydro resources, PGE's benefit detail for the month of December is materially lower than the detail reported in the above referenced work paper. These differences are provided in Attachment 035-D.
Attachment 035-D is protected information subject to Protective Order No. 19-112.

[1] Other categories in the workpaper are the result of calculations contained in the workpaper.
[2] Beginning in May, PGE made updates to its software tools, which provides PGE with the capability to reproduce the Cost and P&L data by category (i.e., not just total) beginning May 2018.

PGE has reviewed the variances provided in Attachment 035-D and concluded that the initial results are an error. After consulting with PGE's software vendor, Power Cost Inc. (PCI), there was likely missing production data when the initial results were calculated. This led to the software tool miscalculating production cost, and overestimating EIM benefit.

b. See Attachment 035-B for the source data used in sheet "Power Cost Unit Summary". The source data are dollars recorded to PGE's general ledger, and the dollars are effectively procurement costs for fuel and emission control chemicals. Attachment 035-C provides the general ledger query results documenting the general ledger entries.

Attachments 035-B and Attachments 035-C are protected information subject to Protective Order No. 19-112.

The power costs are total dollars divided by production for each month, which is effectively an average production cost, not an incremental production cost. With respect to thermal resources, PGE used the average production cost as a proxy cost for the EIM MWh movement in its 2018 benefit calculation, because (1) the data is readily available and (2) consistent with the level of detail in its Net Variable Power Cost settlement reporting. PGE notes that the power cost values are only relevant to PGE's thermal resources.[3]

PGE notes that its proposal to use 2018 actuals as a basis for forecasting 2020 benefits is linked to the finding that production cost model results were similar to PGE's measurement for actuals. As described in PGE Exhibit 100, the modeled result for 2018 used in Docket No. UE 319 (which captured incremental cost and benefits in a more precise manner) produced a benefit estimate of $5.6 million.

c. PGE's objective is to reliably serve load in a manner that minimizes its net variable power costs across time (e.g., term markets, pre-schedule markets, hourly bilateral trading, EIM, etc.) and products (e.g., natural gas, electric power, etc.). In real time, Power Operations monitors PGE's load (both customer and Balancing Authority Area) and generating resources (i.e., hydro, thermal, and wind) in order to adjust (as needed and to the extent possible) procurement and dispatch strategies to maintain reliability on PGE's system and to serve customer load.
As part of PGE's overall effort to maintain reliability on PGE's system and/or minimize net variable power costs, PGE may adjust its energy bids in the EIM to a price that is different from the price produced by a strict operating cost assessment for the relevant trading hour. These bid changes may reflect relevant trading or operational variables such as:

1. opportunity costs (i.e., ability to trade in other markets or at other times),
2. must-run events (i.e., a need to operate a plant no matter the price offered in the market), or
3. use limits (i.e., a need to communicate to the market via a price signal that the resource is energy or fuel limited).

[3] As indicated in #EIM Benefit_Workpaper_Sub-Hour Dispatch_CONF.xlsx, PGE's hydro benefit is measured against hourly Powerdex prices.

When these types of bid adjustments are made, the EIM bid is not directly the operating cost for the trading hour, but it is PGE's best estimate of the bid that can ultimately minimize PGE's Net Variable Power Cost in total over the course of the operating year.

During these events, EIM losses can occur. While the EIM transaction identified in the CAISO market solution will most often be a correct cost minimization decision, this cost minimization decision is limited to data processed by the EIM. When PGE measures the EIM settlement dollars against the resource's operating costs for the month, there can be a loss when the view is limited to EIM market activity only.

d. See PGE's response to part (c).

e. During 2018, a portion of Boardman's losses resulted from instances where there were complications with market unit commitment associated with moving the resource to different operating setpoints. September operations and parts of November operations are examples of complications from unit commitment that led to losses. PGE has taken steps to simplify Boardman's modeling in the EIM and anticipates that losses associated with market complications can be reduced in the future.

   However, Boardman also incurred losses due to plant trips and bidding submittals that sought to reduce net variable power cost overall (not just the EIM). Losses associated with unit trips and overall bidding submittals depend on plant reliability and the overall market dynamics during the operating year. PGE cannot speculate on the impact that these loss categories will ultimately have on Boardman in future years.

f. PGE objects to this request on the basis that it calls for speculation. Subject to and without waiving this objection PGE replies as follows:

   In providing this response, PGE notes that it does not agree with the method to apply a filter based on net incremental MWh. The more appropriate method would be to use the absolute value of MWh movement. The application of the absolute method would lower the loss margin below $5 per MWh in some instances. PGE identifies those instances with an asterisk (*).

   Feb
   ***MIDC_5_PGESHARE**: See part a of this response. With data updates, the loss changed to a benefit.
   ***MIDC_7_DOPDPGESHARE**: See part a of this response. EIM results not as favorable when compared to after-the-fact Powerdex pricing.

   Apr
   ***BRP1_2_BEAVER1-7**: Resource missed its dispatch operating target during operating intervals where the EIM price was higher than operating cost. While it is not a reasonable expectation to have zero uninstructed imbalance energy (UIE), PGE does seek to minimize UIE through active outage management.

CSP1_5_COYOTE1: Plant tripped offline and infeasibility pricing due to under-generation was triggered. PGE cannot speculate on the future level of losses due to unit trips.

<u>Jun</u>
***PNP-RBP_2_PELRB**: PGE used base schedule to create EIM market purchases that turned out to be unfavorable (on an EIM-only basis) during the post-trading settlement review. That is, EIM results not as favorable when compared to after-the-fact Powerdex pricing.

<u>Jul</u>
BRP1_2_BEAVER1-7: PGE experienced complications with unit commitments in the market. In some instances, CAISO identified software defects that resulted in self-schedules not being respected in the market. In other instances, default energy bids calculated by the CAISO market software were too high, resulting in the market determining that the resource was more expensive that the bids initially submitted by PGE. PGE now operates the resource under a different default energy bid preference.

CYP1_5_CARTY1: Resource tripped offline. Infeasibility pricing due to under-generation was triggered. PGE cannot speculate on the future level of losses due to unit trips.

<u>Aug</u>
BNP1_5_BOARDMAN: Infeasibility pricing due to under-generation was triggered during two instances. The first instance was a unit trip during a startup. The second instance was during plant testing. PGE cannot speculate on the future level of losses due to unit trips.

CYP1_5_CARTY1: Resource incurred high amounts of uninstructed imbalance energy (i.e., did not reach dispatch operating target issued by market). Purchases of energy were greater than resource operating cost.

***PWP1_2_PORTWEST1**: Resource incurred high amounts of uninstructed imbalance energy (i.e., did not reach dispatch operating target issued by market). Purchases of energy were greater than resource operating cost.

<u>Sep</u>
***BNP1_5_BOARDMAN**: Complications with unit commitment in the market. Unit commitments issued by market did not align with base schedules submitted by PGE. In some instances, the complications were due to software defects that CAISO has issued software patches to resolve. See PGE's response to part e.

CYP1_5_CARTY1: PGE used base schedule to create EIM market purchases. EIM-only results were not favorable, because EIM purchases were greater than operating cost of the resource. See part c. of this response.

<u>Oct</u>

CYP1_5_CARTY1 and PWP1_2_PORTWEST1: PGE used base schedule to create EIM market purchases. EIM-only results were not favorable, because EIM purchases were greater than operating cost of the resource. See part c. of this response.

Nov
BNP1_5_BOARDMAN: Conflict between outage entry and market unit commitment led to losses in the fifteen-minute market. See PGE's response to part e.

Dec
***BNP1_5_BOARDMAN**: PGE used base schedule to create EIM market purchases. EIM-only results were not favorable, because EIM purchases were greater than operating cost of the resource. See part c. of this response.

CSP1_5_COYOTE1 and CYP1_5_CARTY1: PGE used base schedule to create EIM market purchases. EIM-only results were not favorable, because EIM purchases were greater than operating cost of the resource. See part c. of this response.

g. PGE cannot speculate on the number of plant-month losses in 2020. As noted in part e of the response, there are some types of losses (e.g., plant trips or bidding submittals seeking to reduce overall NVPC) that are dependent on plant reliability and the overall market dynamics during the operating year.