Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● jog@dvclaw.com
1750 SW Harbor Way, Suite 450
Portland, OR 97201

June 30, 2021

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 CO.
2022 Annual Power Cost Update Tariff
Docket No. UE 391

Dear Filing Center:

Please find enclosed the redacted version of the Opening Testimony and Exhibits of Bradley G. Mullins (AWEC/100 – 104) and Lance D. Kaufman (AWEC/200 – 202) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced dockets.

Please note that AWEC's testimony and exhibits contain Protected Information that is being handled in accordance with Order No. 21-099. The confidential portions of AWEC's filing have been encrypted with 7-zip software and are being transmitted electronically to the Commission and qualified persons.

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

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **Confidential Opening Testimony and Exhibits of the Alliance of Western Energy Consumers** upon the parties shown below via electronic mail.

Dated at Portland, Oregon, this 30th day of June, 2021.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

CITIZENS' UTILITY BOARD OF OREGON
MICHAEL GOETZ
WILLIAM GEHRKE
610 SW BROADWAY STE 400
PORTLAND OR 97205
mike@oregoncub.org
will@oregoncub.org

PUBLIC UTILITY COMMISSION OF OREGON
MOYA ENRIGHT
OPUC
P.O. BOX 1088
SALEM OR 97308
moya.enright@state.or.us

PUC STAFF - DEPARTMENT OF JUSTICE
STEPHANIE S. ANDRUS
BUSINESS ACTIVITIES SECTION
1162 COURT ST NE
SALEM OR 97301
stephanie.andrus@state.or.us

PORTLAND GENERAL ELECTRIC
LORETTA MABINTON
PORTLAND GENERAL ELECTRIC
121 SW SALMON – 1WTC 1711
PORTLAND, OR 97204
loretta.mabinton@pgn.com

PORTLAND GENERAL ELECTRIC
JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
121 SW SALMON – 1WTC 0306
PORTLAND, OR 97204
jacquelyn.ferchland@pgn.com
pge.opuc.filings@pgn.com

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 391

In the Matter of	)
	)
Portland General Electric Company,	)
	)
2022 Annual Power Cost Update Tariff	)
(Schedule 125)	)
	)

OPENING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

June 30, 2021

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AWEC/101 – Qualification Statement of Bradley G. Mullins

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Confidential AWEC/104 – Avangrid Capacity Contract Analysis

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found at Exhibit AWEC/101.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from Portland General Electric ("PGE"). Witness Lance Kaufman will also be providing testimony on behalf of AWEC in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PGE's proposed Annual Update Tariff ("AUT"), including Net Variable Power Costs ("NVPC"), for calendar year 2022. Specifically, I discuss my review of PGE's proposed $38,942,825 revenue increase associated with the 2022 AUT filing.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations are summarized in Table 1, below, followed by brief descriptions of each issue. In addition, Table 1 also details the impact of adjustments proposed by AWEC witness Kaufman. Since witness Kaufman's recommendations related to the Lydia 2.0 modeling adjustment have a material impact on certain adjustments proposed in this testimony, Table 1 includes a column detailing the impact of AWEC adjustments both with, and without, the Lydia 2.0 modeling.

Table 1
AWEC Proposed AUT Adjustments
($000)

		Excluding Lydia 2.0	With Lydia 2.0
1	**Initial Filing**	**511,766,273**	**511,766,273**
2	Adjustments		
3	Lydia 2.0 (Kaufman)	(5,614,066)	-
4	EIM Benefits (Kaufman)	(742,000)	(742,000)
5	Exclude Refinements (Kaufman)	(1,823,000)	(1,823,000)
6	PTC Rate	(1,555,045)	(1,555,045)
7	Wheatridge Battery Storage	(116,407)	(116,407)
8	Day-Ahead Forecast Error	(1,158,437)	(1,158,437)
9	COB Margins	(1,652,583)	(5,628,508)
10	Avangrid Capacity Contract	(594,860)	(624,411)
11	Total Adjustments	(13,256,398)	(11,647,808)
12	**Adjusted**	**498,509,875**	**500,118,465**

Production Tax Credit Rate: I recommend updating the production tax credit ("PTC") rate for 2022 to 2.6¢/kWh.

Wheatridge Battery Storage Optimization: I recommend improving the dispatch associated Wheatridge battery storage system, which is uneconomic based on PGE's modeling.

Day-Ahead Forecast Error – I recommend removing the day-ahead forecast error adjustment for wind facilities, since MONET already considers the incremental production cost of dispatching on an hour-ahead basis.

COB Margins – I recommend that the California-Oregon Border ("COB") margins adjustment be calculated by hour, rather than by month, to produce a benefit value that is more consistent with historical data.

Avangrid Capacity Contract – I recommend calculating the dispatch benefits of the Avangrid capacity contract in a manner that is consistent with the hourly market prices input into MONET.

II. PRODUCTION TAX CREDIT RATE

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO PRODUCTION TAX CREDITS ("PTC").

A. PGE's AUT filing assumes a PTC rate equal to 2.5¢/kWh for the 2022 forecast period. The 2.5¢/kWh rate was acknowledged on April 27, 2021, by the Internal Revenue Service ("IRS") as the PTC rate for 2021.[1/] Notwithstanding, in 2022—the year in which the proposed NVPC at issue in this proceeding will be in effect—the PTC rate will increase to 2.6¢/kWh, as discussed below. Accordingly, I recommend updating PGE's forecast to be based on a 2.6¢/kWh PTC rate. The impact of using a 2.6¢/kWh PTC rate is a $1,555,045 reduction to NVPC.

Q. WHAT CAUSES THE PTC RATE TO CHANGE FROM YEAR-TO-YEAR?

A. The PTC rate is established pursuant to Internal Revenue Code ("IRC") § 45.[2/] The PTC rate was first authorized in 1993 and established at a baseline of 1.5¢/kWh. To account for inflation, the IRS adjusts the PTC rate each year by applying an "inflation adjustment factor." In IRC § 45(e)(2)(B), the calculation of the inflation adjustment factor is outlined as follows:

> The term "inflation adjustment factor" means, with respect to a calendar year, a fraction the numerator of which is the [Gross Domestic Product ("GDP")] implicit price deflator for the preceding calendar year and the denominator of which is the GDP implicit price deflator for the calendar year 1992. The term "GDP implicit price deflator" means the most recent revision of the implicit price deflator for the gross domestic product as computed and published by the Department of Commerce before March 15 of the calendar year.[3/]

1/ 86 Fed. Reg. 22300-22301 (Apr. 27, 2021).
2/ 26 U.S.C. § 45(b)(2) (2021).
3/ IRC § 45(e)(2)(B).

In addition, when applying the inflation adjustment factor, the credit rate is rounded to the nearest multiple of 0.1¢/kWh. Consequently, while the inflation adjustment factor changes every year, the PTC rate does not necessarily change each year. For example, in 2022, the unrounded PTC rate would need to exceed 2.550¢/kWh to trigger an increase to 2.6¢/kWh.

Q. WHAT WAS THE INFLATION ADJUSTMENT FACTOR FOR 2021?

A. The inflation adjustment factor for 2021 was 1.6878, resulting in an unrounded PTC rate of 2.5317 ¢/kWh. Thus, while the PTC rate rounded down to 2.5¢/kWh in 2021, the unrounded PTC credit rate was within 0.0183¢/kWh of 2.550¢/kWh and rounding up to 2.6¢/kWh.

Q. WHAT INFLATION ADJUSTMENT FACTOR WILL RESULT IN AN INCREASE TO THE PTC RATE?

A. The inflation adjustment factor must equal or exceed 1.700 to trigger an increase in the PTC rate to 2.6¢/kWh. Whether this level is achieved, however, depends on the annual gross domestic product ("GDP") implicit price deflator, which, as noted above, is an economic index of inflation published by the Department of Commerce, Bureau of Economic Analysis ("BEA"). The GDP implicit price deflator is published quarterly. Accordingly, based on information that is known about the GDP implicit price deflator today, it can be determined whether the inflation adjustment factor for 2022 will be sufficient to cause the PTC rate to round up to 2.6¢/kWh.

Q. HOW DOES THE GDP IMPLICIT PRICE DEFLATOR DETERMINE THE INFLATION ADJUSTMENT FACTOR?

A. Exhibit AWEC/102 contains an analysis showing how the GDP implicit price deflator is used to calculate the PTC inflation adjustment factor. As noted in IRC § 45(e)(2)(B), the calculation of the inflation adjustment factor is a simple fraction.

The numerator of the fraction is equal to the GDP implicit price deflator for the calendar year prior to the tax year. For tax year 2022, for example, the numerator will be based on the GDP implicit price deflator from calendar year 2021.

The denominator of the fraction is equal to the GDP implicit price deflator for 1992, the calendar year prior to the 1993 tax year when the PTC was first implemented.

The denominator of the inflation adjustment factor is a known value. The GDP implicit price deflator for calendar year 1992 was 67.325.[4/] Thus, while the precise value for the inflation adjustment factor for calendar year 2022 is not yet known, the quarterly GDP price deflator values that the BEA publishes can be used to determine whether the ultimate inflation adjustment factor will exceed 1.700 in 2022 and trigger an increase to the PTC rate.

Q. WHAT GDP PRICE DEFLATOR VALUE WILL TRIGGER AN INCREASE TO THE PTC RATE?

A. Since the denominator of the inflation adjustment factor is known to be 67.325, it can be concluded that a GDP implicit price deflator of 114.45 or more will result in an inflation adjustment factor of 1.700 and a corresponding increase to the PTC rate to 2.6¢/kWh.

Q. IS ENOUGH DATA AVAILABLE AT THIS TIME TO DETERMINE WHETHER THE GDP IMPLICIT PRICE DEFLATOR WILL EXCEED 114.45 FOR 2021?

A. Yes. Based on the GDP implicit price deflator published for Q1 of 2021, it can be concluded with reasonable certainty that the annual 2021 GDP implicit price deflator will exceed 114.450. Accordingly, it also can be concluded that the 2022 PTC Inflation Adjustment Factor will exceed 1.700, and as a result, the 2022 PTC rate will round to 2.6¢/kWh, consistent with the discussion above.

[4/] This is based on the current index values. Note that the baseline year used to establish the GDP implicit price deflator index value has been updated, which can be seen in Exhibit AWEC/102.

The annual GDP implicit price deflator represents an average over the course of the calendar year. The annual GDP implicit price deflator is not, for example, based on the year end value. Rather, the amount is calculated over four quarters and the average of those quarterly values is used to derive the annual value.

In 2020, for example, the average annual GDP implicit price deflator was 113.625. Notwithstanding, the Q4 2020 the GDP implicit price deflator index value was higher than that value. In Q4 2020, the GDP implicit price deflator increased to 114.368, within only 0.082 of the threshold value necessary to trigger the PTC rate change under discussion.

As detailed in Exhibit AWEC/102, the GDP implicit price deflator index value increased to 115.514 in Q1 of 2021, exceeding the 114.450 threshold value by a margin of 1.564. Since the annual value is calculated as an average and the threshold value has already been exceeded in Q1 of 2021, the GDP implicit price deflator value would need to decline by a significant amount in each of the three remaining quarters of 2021 for the average annual value to decline back below the 114.450 threshold value. In other words, the economy would need to fall into a recession, with three quarters of unprecedented deflation, for the annual GDP implicit price deflator to decline back below 114.450 and for the PTC rate to remain at 2.5¢/kWh. As I discuss below, the level of deflation necessary for the GDP implicit price deflator index to decline below 114.450 as an annual average—and thus the PTC rate to remain at 2.5¢/kWh—is so unlikely as to be near impossible. Therefore, while the precise GDP implicit price deflator for 2021 is not yet known at this juncture, it can be concluded that the average GDP implicit price deflator will exceed 114.50 for 2021 and that the PTC rate will increase to 2.6¢/kWh in 2022.

Q. WHAT MAGNITUDE OF DEFLATION WOULD BE REQUIRED FOR THE GDP IMPLICIT PRICE DEFLATOR TO DECLINE BELOW 114.50?

A. Mathematically, for the GDP implicit price deflator to decline back below 114.50 and thus not trigger an upward rounding of the PTC rate, the economy would need to experience deflation of 0.62% in each of the three remaining quarters of 2021. This calculation is shown in Exhibit AWEC/102. On a cumulative basis, such a scenario would represent deflation of 1.84% over the three-quarter period. Such a level of inflation would have no precedent in modern history, particularly since the abolition of the gold standard in the 1970s. During the period of modern monetary policy, when the dollar has been decoupled from gold prices, there have been only four instances of modest deflation, as measured by the GDP implicit price deflator—and none of those instances have come remotely close to deflation of 1.84%.[5/] In the 2008 financial crisis, for example, the GDP implicit price deflator declined by 0.16%. Further, in Q1 of 2015, modest deflation was experienced, corresponding to a 0.09% reduction to the GDP implicit price deflator. Similarly, in Q1 of 2016, modest deflation corresponding to a 0.07% reduction to GDP implicit price deflator was also experienced. Finally, in Q2 of 2020, corresponding to the onset of the COVID-19 pandemic, GDP implicit price deflator declined by 0.53%. All of these instances, however, were limited to a single quarter. Thus, experiencing deflation of 1.84% over a three-quarter period would represent an unprecedented catastrophe that is more than three times more significant than what has recently been experienced due to the COVID-19 pandemic. Given the health of the economy in 2021 to date, such an outcome is a near impossibility.

5/ The historical data is provided in my workpapers.

Q. WHAT LEVEL OF INFLATION IS EXPECTED FOR THE REMAINDER OF 2021?

A. We will know more about the economic condition in 2021 as this case progresses. However, the general consensus in the financial press is that, as a result of the easing of the COVID-19 pandemic, prices will increase. Certainly, inflationary expectations have been high in the past few months. Prices of lumber, for example, have experienced record high levels during the first half of 2021.

Further, as of writing this testimony, Q2 2021 is underway. Based on the general health of the economy, it can be observed that catastrophic deflation is not being experienced in Q2 2021. Based on this observation, it can be concluded that the likelihood of catastrophic deflation necessary for the PTC rate to remain at 2.5¢/kWh is even more remote. If one simply assumes that the GDP implicit price deflator will remain constant in Q2 of 2021 (i.e., 0% inflation), the level of deflation in Q3 and Q4 necessary for the PTC rate to stay at 2.5¢/kWh is 2.45% on a cumulative basis. Based on this observation and the discussion above, I recommend increasing the PTC rate to 2.6¢/kWh as a known and measurable change in this proceeding.

III. WHEATRIDGE BATTERY STORAGE OPTIMIZATION

Q. PLEASE DISCUSS THE BATTERY STORAGE SYSTEM AT WHEATRIDGE.

A The Wheatridge Energy Park was selected in PGE’s 2018 Renewable Request for Proposal.[6/] The Wheatridge Energy Park includes 300 MW nameplate of wind (100 MW owned and 200 MW under a power purchase agreement (“PPA”) with NextEra); 50 MW of solar under a PPA with NextEra; and a 30 MW four-hour battery storage system coupled with the solar PPA with

[6/] Docket No. UM 1934, Order No. 18-483 (Dec. 19, 2018).

NextEra. The battery storage system is connected to the Wheatridge solar facility, and therefore, can only be charged using output from the solar facility. Since the solar facility only produces in the day-time hours, this results in a physical limitation for when the battery can be charged. Further, NextEra, the owner of the battery storage system, has imposed several contractual operating limitations on the battery storage system, restricting how and when the system may be used. For example, after completing a full charge, the battery must rest for four hours. Similarly, following a charge, the battery must be discharged within 24 hours.

Q. WHAT IS THE COST OF THE ENERGY STORAGE SYSTEM?

A. The annual cost of the battery storage system is $[redacted].

Q. HOW DOES PGE MODEL THE BATTERY STORAGE SYSTEM IN MONET?

A. PGE models the battery storage system as an adjustment to the output from the Wheatridge solar facility. The solar facility itself is modeled using a static, monthly diurnal profile. Thus, for every hour of a given month, the solar facility is assumed to produce the same amount of energy. To account for the battery storage system, PGE adjusted the monthly diurnal profile of the solar facility assuming a schedule of charging and discharging that is the same for every day of a given month. The methodology assumes that the battery charges in the morning and discharges in the evening, following a four-hour rest period.

Q. DO YOU AGREE WITH PGE'S APPROACH?

A. No. PGE's approach results in a suboptimal use of the battery storage system. It does not, for example, consider how market prices impact the timing of when it is most cost effective to charge and discharge.

Q. DOES PGE FORECAST THE BATTERY STORAGE SYSTEM TO PRODUCE BENEFITS IN MONET?

A. No. Based upon PGE's modeling, the Wheatridge battery storage system produces a net system energy cost of $[redacted]. When viewed by month, the battery storage dispatch associated with PGE's modeling is uneconomic for the majority of the year. This can be seen in Confidential Table 2, below:

Confidential Table 2
Cost / (Benefit) of Wheatridge Battery Storage System ($)

[redacted]

Thus, even though the battery storage system was assumed to dispatch in every month, it was only economic to use, based on PGE's fixed, monthly-diurnal modeling, in the months of May through August.

Q. IS THERE A BETTER WAY TO MODEL THE BATTERY?

A. Yes. In my workpapers, I prepared a screening study that develops a more optimal profile of charging and discharging of the battery storage. The analysis is performed on an hourly basis and considers the timing of when market prices are lowest when charging and when market prices are the highest when discharging. The analysis also considers the various operating constraints that were set out in the contract.

Q. WHAT WERE THE RESULTS OF YOUR STUDY?

A. Confidential Table 3, below, details the results of my hourly analysis:

Confidential Table 3
<u>Net Energy Benefit of Battery Storage in Alternate Screening Study</u>

[redacted]

Confidential Table 3, above, compares the cost of a charging versus discharging using the more optimal dispatch profile in my analysis. As can be seen, the volume of MWhs charged is more than the volume discharged, which is due to the losses that occur when charging and discharging the battery system. It can be noted that the $/MWh value of the charge is slightly less than the $/MWh of the discharge, resulting in a positive margin associated with charging. Further, an availability factor is applied at the end representing the guaranteed storage availability in the NextEra contract. The availability factor is a minimum and low in the first year of operation, relative to later years. Under my study the battery storage system produces an energy benefit of $[redacted] per year, in contrast to the $[redacted] of additional cost PGE assumed.

Q. DOES THIS BENEFIT JUSTIFY THE EXPENSE?

A. Even assuming more optimal dispatch, the energy value of the storage system is still well below the annual cost. While the cost of batteries has been declining, it is important to keep in mind that batteries are not 100% efficient. Batteries are usually about 90% efficient, meaning that for every 100 MWh charged, the battery only returns about 90 MWh of electricity. Further, the dispatch restrictions placed on the storage system by NextEra also limit the value of the battery storage system. For instance, because the system was coupled with the solar facility, the battery can only be charged in periods when solar is producing, which may be the times with highest market prices. Similarly, the battery is limited in its ability to discharge during the day, when the solar is producing.

From this perspective, it is likely that there are greater benefits associated with installing distributed, stand-alone battery storage facilities collocated with distribution and transmission facilities. Such a system could still take advantage of low-priced energy during periods of high solar penetration. Stand-alone storage systems, however, could be charged and discharged at any time of the day. Stand-alone storage systems would also be able to avoid transmission losses, and possibly provide other distribution planning benefits. Needless to say, more thorough analysis of battery storage systems is warranted in future Integrated Resource Planning and RFP proceedings.

Q. ARE THERE OTHER FACTORS THAT PGE DID NOT CONSIDER IN THIS DOCKET THAT WERE ASSUMED IN THE 2018 RFP?

A. Yes. The battery storage system was assumed to provide a significant amount of flexibility benefits in the 2018 Renewable RFP. Given the dispatch constraints laid out in the contract, it is not clear if ratepayers will realize those flexibility benefits in actual operations. PGE appears to not have considered any flexibility benefits associated with the Wheatridge battery storage in the AUT.

Q. WHAT DO YOU RECOMMEND?

A. I recommend modeling the Wheatridge battery storage based on the modified dispatch profile discussed above. When modeled in MONET, the impact of this adjustment is a $116,407 reduction to NVPC relative to PGE's modeling.

Further, I request that PGE identify the amount of flexibility reserve benefits associated with the battery storage system included in NVPC compared to the amount assumed in the 2018 Renewable RFP. A further adjustment may be necessary if the flexibility benefits have not been modeled in a manner consistent with the RFP justifying the battery storage system.

IV. DAY-AHEAD FORECAST ERROR

Q. WHAT AMOUNTS DOES PGE INCLUDE IN NVPC RELATED TO DAY AHEAD FORECAST ERROR?

A. PGE's forecast includes a [redacted] $/MWh rate that is applied to each of PGE's owned wind facilities which it attributes to day-ahead forecast error costs.

Q. HOW DID PGE ARRIVE AT THE RATE USED FOR THE DAY-AHEAD FORECAST ERROR?

A. The day-ahead forecast error rate was based on a series of production cost modeling runs prepared in in PGE's 2017 Wind Integration Study. Effectively, PGE performed two production cost model runs to come up with the day-ahead forecast error rate. First, PGE performs a production cost model run calculating the cost of dispatch assuming wind production based on the day-ahead wind forecast. Second, PGE performs a production cost model run calculating the cost of dispatch assuming the wind production based on the hour-ahead wind forecast. PGE takes the difference in cost between those two runs and unitizes the result over the total amount of wind production to arrive at a volumetric rate, which PGE attributes to day-ahead forecast error.

Q. DO YOU AGREE WITH INCLUDING THIS AMOUNT IN NVPC?

A. No. The MONET model dispatch is not based on the day-ahead wind forecasts. The MONET model, particularly with the new dynamic wind profiles associated with Lydia 2.0, already simulates the cost associated with dispatch in hourly markets based upon the equivalent of an hour-ahead wind forecast. Accordingly, the MONET model already includes the cost associated with moving from a day-ahead to hour-ahead wind forecast.

Q. DOES PGE ACTUALLY DISPATCH ITS SYSTEM BASED UPON A DAY-AHEAD WIND FORECAST?

A. No. While PGE might make transactions based upon its day-ahead wind forecast, the ultimate dispatch is not based on the day-ahead, preschedule forecast. Rather, it is based on hourly schedules. With BPA, PGE has the ability to modify its scheduled system dispatch up to 90 minutes before the hour to account for the dynamic nature of the wind output. PGE's model already includes reserves to manage the flexibility, regulating and operating requirements associated with its wind resources, and adding in an additional cost associated with a day-ahead forecast error is not necessary.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE DAY-AHEAD FORECAST ERROR CALCULATION?

A. Yes. PGE applies inflationary escalation to the day-ahead forecast error rate. The day-ahead forecast error, however, does not necessarily change in relationship to inflation. If prices increase, for example, the increase impacts both the day-ahead production costs and the hour-ahead production costs. It changes based on the relationship between the day-ahead and the hour-ahead forecast. Thus, including an inflationary escalator is not necessary or appropriate. Even if the day-ahead forecast error is applied in the MONET model, it is necessary to remove the inflationary escalation, which reduces NVPC by $115,628.

Q. WHAT DO YOU RECOMMEND?

A. I propose excluding the day-ahead forecast error amount from NVPC altogether. This recommendation reduces NVPC by $1,158,437.

V. CALIFORNIA-OREGON-BORDER MARGINS

Q. PLEASE PROVIDE SOME BACKGROUND ON COB MARGINS.

A. The COB margins adjustment was originally proposed by AWEC[7/] in Docket UE 308. The MONET model assumes that all purchase and sale transactions are being made at the Mid-Columbia ("Mid-C") market. Notwithstanding, PGE possesses transmission rights to the COB market, which enables PGE to monetize the price differences between the Mid-C market and COB market, where possible. In some hours, COB market prices are higher than Mid-C

[7/] Through its predecessor, the Industrial Customers of Northwest Utilities.

market prices; in other hours, COB market prices are lower than Mid-C market prices. Given sufficient transmission capability, PGE can monetize the price spreads, relative to the Mid-C market, by purchasing when the spread is positive and selling when the spread is negative. The COB margins adjustment was designed to capture this benefit in MONET.

Q. HOW DOES PGE MODEL COB MARGINS IN MONET?

A. PGE models the COB margins adjustment in MONET as a financial adjustment, meaning it does not impact plant dispatch in the model. PGE calculated the adjustment based on the monthly diurnal price spreads between the Mid-C market and the COB market in the forecast period. PGE then applies the price spreads to the monthly diurnal volumes calculated as an average over the period 2018 – 2020. Where the price spreads were positive in a particular hour of the monthly diurnal profile, PGE assumed a sale based on the historical average for that monthly period. Similarly, where the price spreads were negative in a particular hour of the monthly diurnal profile, PGE assumed a purchase based on the historical average for that monthly period. Notwithstanding, each period had both sales and purchases associated with it, and accordingly, PGE's approach restricted the volume of transactions by assuming that each period was either a sale or a purchase.

Q. IS IT APPROPRIATE TO MODEL COB MARGINS AS A FINANCIAL ADJUSTMENT?

A. Modeling COB margins as a financial adjustment understates the value of being able to transact at the COB market. As a result of having transmission access to multiple markets, PGE will be able to dispatch its power plants more efficiently. The financial adjustment does not consider this improved dispatch. Including the COB market directly in MONET, however, would require significant modifications to the model logic, which may not be feasible.

Q. WHAT WAS THE HISTORICAL VALUE OF COB MARGINS OVER THE PERIOD 2018 – 2020?

A. In its workpaper "#08_COB2018-20WeightedShape_2.26.2021 Curves", PGE provided the historical transactions at the COB market and the associated prices for those transactions. Compared to the hourly Mid-C prices, which are used to inform the Lydia 2.0 price shaping calculation, the historical financial benefit PGE has recognized as a result of transacting at the COB market can be seen in Confidential Table 5, below:

Confidential Table 5
Actual COB Margins 2018 – 2020 Compared to PGE Forecast

[redacted]

The left three columns of the above table detail the historical margins that PGE has recognized by transacting at the COB market. In addition to the historical values, Table 5 also details the amounts that PGE has assumed in its filing. As can be seen, PGE's approach produces volumes and margins that are well below the historical averages. In fact, PGE's estimate of COB margins in the AUT is less than half the historical average over the period 2018 through 2020. The column on the right also details the impact of AWEC's proposed modifications to the methodology, discussed below.

Q. WHY DOES PGE'S APPROACH RESULT IN SUCH A SMALLER BENEFIT ASSOCIATED WITH COB MARGINS?

A. The primary reason for the difference between PGE's forecast and the historical data is the use of a monthly diurnal profile to calculate the volumes and price spreads associated with the COB margins adjustments. This approach restricts the volume of transactions relative to the historical average because it assumes that PGE is making the same daily profile of sales and purchase in every day of the month. It also limits the price spreads, which are representative of a wider range of price spreads if viewed on an hourly basis, rather than a single monthly diurnal profile.

Q. WHAT ANALYSIS HAVE YOU PERFORMED?

A. In Confidential Exhibit AWEC/103, I detail an updated version of the COB margins calculation. It uses a similar approach as PGE, which ties the volume of transactions to the historical averages. Notwithstanding, the approach does not limit the volumes by monthly, diurnal periods, but rather calculates a transaction limit on a monthly basis. Further, the historical data suggests that the overall margins on purchases at the COB market are small, and in some years negative. When calculating the volumes, I netted any sales and purchases made on the same hour of the same day, which was necessary to prevent overstating the adjustment when there were both sales and purchases in the same hour.

Q. WHAT WAS THE RESULT OF YOUR ANALYSIS?

A. My analysis resulted in COB market transaction sales volumes of [redacted] MWh and purchase volumes of [redacted] MWh. These levels of sales and purchases are in line with, but slightly lower than, the historical averages. Further, the analysis resulted in an average price spread of $[redacted]/MWh for sales transactions and an average price spread of $[redacted]/MWh for purchase transactions. The sales transaction spreads are also slightly lower than the historical average values. The market spreads associated with purchase transactions are slightly higher than the historical average, albeit are being applied against a relatively small amount of volume, producing an overall margin value that is in line with the historical data. The result of the analysis was a COB Margins calculation of $[redacted], which is still 39% lower than the historical average.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the hourly COB Margins methodology identified in Confidential Exhibit AWEC/103 be used in NPC, which produces results that are more in line with historical averages. Using that analysis results in a $5,628,508 reduction to NVPC based on the Lydia 2.0 model prices and a $1,652,583 adjustment based on the Lydia 1.0 model prices.

VI. AVANGRID CAPACITY CONTRACT

Q. WHAT IS THE AVANGRID CAPACITY CONTRACT?

A. The Avangrid contract provides for 100 MW capacity in winter and summer months based on the cost of the [redacted], a 100 MW simple cycle combustion turbine located in [redacted]. The price is based on the cost of energy from the underlying power plant. The pricing parameters of the contract are detailed in Confidential Exhibit AWEC/104.

Q. WHAT IS YOUR CONCERN WITH PGE'S MODELING OF THE CONTRACT?

A. PGE models the contract as a financial option that dispatches depending on whether market prices exceed the contract pricing parameters. PGE, however, modeled the contract on a monthly basis assuming a static dispatch for the entire month, rather than viewing how the contract would dispatch based on the granular hourly prices assumed in the MONET model.

Q. HAVE YOU ANALYZED THE IMPACT OF ASSUMING THE HOURLY PRICES WHEN CALCULATING THE CONTRACT DISPATCH?

A. Yes. Confidential Exhibit AWEC/104 provides an analysis with an updated dispatch profile based on the hourly prices in the MONET model.

Q. WHAT IS THE IMPACT OF YOUR ANALYSIS?

A. As can be seen from the analysis, relative to PGE's monthly modeling, the dispatch benefits of the Avangrid capacity contract increase by $624,411 when calculated on an hourly basis using the hourly prices from the Lydia 2.0 model. If prices from the Lydia 1.0 model are used, the incremental benefit of dispatching the contract hourly declines to $594,860.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 391

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
2022 Annual Power Cost Update Tariff.	)
	)

EXHIBIT AWEC/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

MW ANALYTICS
Energy & Utility Consulting

Brad Mullins
Principal Consultant
Vihiluoto 15
FIN-90440 Kempele, Finland
USA +1 503 841-1465
brmullins@mwanalytics.com
www.mwanalytics.com

ABOUT

MW Analytics is the professional consulting practice of Brad Mullins, a consultant and expert witness that represents utility customers in regulatory proceedings before state utility commissions throughout the Western United States. Brad has sponsored expert witness testimony in over 70 regulatory proceeding encompassing a variety of subject matters, including revenue requirement, regulatory accounting, rate development, and new resource additions. Brad has also assisted his clients through numerous informal regulatory, legislative and energy policy matters. In addition to providing regulatory services, MW Analytics also provides advisory, energy marketing and other energy consulting services.

PRACTICE AREAS

MW Analytics has experience representing customer interests in litigated and informal regulatory proceedings, including the following subject areas:

- Revenue Requirement
- Power Cost Modeling
- Tax Provisions and Tax Reform
- Capital Additions and Forecasting
- Regulatory Accounting
- Depreciation Studies
- Ratemaking Mechanisms
- Integrated Resource Planning
- Avoided Cost Calculations
- Utility Plant Retirements

EDUCATION AND WORK EXPERIENCE

Brad has a Master of Accounting degree from the University of Utah. After obtaining his master's degree, Brad worked at Deloitte Tax in San Jose, California, where he was responsible for preparing corporate tax returns for multinational corporate clients and partnership returns for hedge fund clients. Brad was later promoted to a Tax Senior position in a national tax practice specializing research and development tax credit studies. Following Deloitte, Brad worked at PacifiCorp Energy, as an analyst involved in power cost modeling and forecasting. At PacifiCorp Brad was responsible for preparing power cost forecasts and supporting testimony for regulatory filings, preparing annual power cost deferral filings, and developing qualifying facility avoided cost calculations.

REGULATORY APPEARANCES

Brad has sponsored expert witness testimony in the following regulatory proceedings:

Docket	Party	Topics
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of a regulatory asset account to recover costs relating to the development and implementation of their Joint Natural Disaster Protection Plan, PUC NV. Docket No. 21-03004	Wynn Las Vegas, LLC; Smart Energy Alliance	Single-Issue Rate Filing

In re PacifiCorp d.b.a. Pacific Power, 2022 Transition Adjustment Mechanism, Or.PUC Docket No. UE 390	Alliance of Western Energy Consumers	Power co
In re Avista 2020 General Rate Case, Wa.U.T.C. Docket No. UE-200900 (Cons.)	Alliance of Western Energy Consumers	Revenue Requirement
In re NV Energy's Fourth Amendment to Its 2018 Joint Integrated Resource Plan, PUC Nv. Docket No 20-07023	Wynn Las Vegas, LLC; Smart Energy Alliance	Transmission Planning
In Re Cascade Natural Gas Corporation, 2020 General Rate Case, Wa.U.T.C. Docket No. UG-200568	Alliance of Western Energy Consumers	Revenue Requirement
In re Cascade Natural Gas Corporation, Petition to File Depreciation Study, Or.PUC Docket No. UM 2073	Alliance of Western Energy Consumers	Depreciation Rates
In re the Application of Rocky Mountain Power for Authority to Increase Current Rates By $7.4 Million to Recover Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $604 Thousand Under Tariff Schedule 93, Rec and So2 Revenue Adjustment Mechanism, Wy.PSC Docket No. 20000-582-EM-20	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re the Complaint of Willamette Falls Paper Company and West Linn Paper Company against Portland General Electric Company, Or.PUC Docket No. UM 2107	Willamette Falls Paper Company	Consumer Direct Access, Tariff Dispute
In re The Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4, Wy.PSC Docket No. 2000-578-ER-20	Wyoming Industrial Energy Consumers	Power Cost Modeling
Avista Corporation 2021 General Rate Case, Or.PUC Docket No. UG 389	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re NW Natural Request for a General Rate Revision, Or.PUC Docket No. UG 388.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol, Or.PUC, UM 1050.	Alliance of Western Energy Consumers	Jurisdictional Allocation
In re Puget Sound Energy 2019 General Rate Case, Wa.UTC Docket No. UE 190529.	Alliance of Western Energy Consumers	Revenue Requirement, Coal Retirement Costs
Avista Corporation 2020 General Rate Case, Wa.UTC Docket No. UE-190334 (Cons.)	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Cascade Natural Gas Corporation Application for Approval of a Safety Cost Recovery Mechanism, Or. PUC Docket No. UM 2026	Alliance of Western Energy Consumers	Ratemaking Policy
In re Avista Corporation, Request for a General Rate Revision, Or.PUC Docket No. UG 366.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Portland General Electric, 2020 Annual Update Tariff (Schedule 125), Or.PUC Docket No UE 359.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp 2020 Transition Adjustment Mechanism, Or.PUC Docket No. UE 356.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp 2020 Renewable Adjustment Clause, Or.PUC Docket No. UE 352.	Alliance of Western Energy Consumers	Single-Issue Rate Filing
2020 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-20	Alliance of Western Energy Consumers	Revenue Requirement, Policy
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	Madison Square Garden	Customer Direct Access
Puget Sound Energy 2018 Expedited Rate Filing, Wa.UTC Dockets UE-180899/UG-180900 (Cons.).	Alliance of Western Energy Consumers	Revenue Requirement, Settlement

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.	Georgia Pacific	Customer Direct Access
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.	Smart Energy Alliance	Resource Planning
In re Cascade Natural Gas Corporation Request for a General Rate Revision, Or.PUC, Docket No. UE 347.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Portland General Electric Company Request for a General Rate Revision, Or.PUC Docket No UE 335.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Or.PUC Docket No. UG 344.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Cascade Natural Gas Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-170929.	Northwest Industrial Gas Users	Revenue Requirement, Rate Design
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.	Alliance of Western Energy Consumers	Merger
Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision, Ut.PSC Docket No. 17-035-40	Utah Industrial Energy Consumers, & Utah Associated Energy Users	New Resource Addition
In re PacifiCorp, dba Rocky Mountain Power, for a CPCN and Binding Ratemaking Treatment for New Wind and Transmission Facilities, Id.PUC Case No. PAC-E-17-07	PacifiCorp Idaho Industrial Customers	New Resource Addition
In re PacifiCorp, dba Pacific Power, 2016 Power Cost Adjustment Mechanism, Or.PUC, Docket No. UE 327.	Alliance of Western Energy Consumers	Power Cost Deferral
In re PacifiCorp 2016 Power Cost Adjustment Mechanism, Wa.UTC Docket No. UE-170717	Boise Whitepaper, LLC	Power Cost Deferral
In re Avista Corporation 2018 General Rate Case, Wa.UTC Dockets UE-170485 and UG-170486 (Consolidated).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
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.	Smart Energy Alliance	Revenue Requirement
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).	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re the 2018 General Rate Case of Puget Sound Energy, Wa.UTC, Docket No. UE-170033 (Cons.).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
In re PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 323.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 319.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company, Application for Transportation Electrification Programs, Or.PUC, UM 1811.	Industrial Customers of Northwest Utilities	Electric Vehicle Charging

In re Pacific Power & Light Company, Application for Transportation Electrification Programs, Or.PUC, Docket No. UM 1810.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
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.	Industrial Customers of Northwest Utilities	Qualifying Facilities
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.	Boise Whitepaper, LLC	Customer Direct Access
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.	Industrial Customers of Northwest Utilities	Customer Direct Access
2018 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-18.	Industrial Customers of Northwest Utilities	Revenue Requirement, Policy
In re Portland General Electric Company Application for Approval of Sale of Harborton Restoration Project Property, Or.PUC, Docket No. UP 334 (Cons.).	Industrial Customers of Northwest Utilities	Environmental Deferral
In re An Investigation of Policies Related to Renewable Distributed Electric Generation, Ar.PSC, Matter No. 16-028-U.	Arkansas Electric Energy Consumers	Net Metering
In re Net Metering and the Implementation of Act 827 of 2015, Ar.PSC, Matter No. 16-027-R.	Arkansas Electric Energy Consumers	Net Metering
In re the Application of Rocky Mountain Power for Approval of the 2016 Energy Balancing Account, Ut.PSC, Docket No. 16-035-01	Utah Associated Energy Users	Power Cost Deferral
In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-160228 (Cons.).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
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.	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 307.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125), Or.PUC, Docket No. UE 308.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Pacific Power & Light Company, General rate increase for electric services, Wa.UTC, Docket No. UE-152253.	Boise Whitepaper, LLC	Revenue Requirement, Rate Design
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.	Wyoming Industrial Energy Consumers	Power Cost Modeling
In re Avista Corporation, General Rate Increase for Electric Services, Wa.UTC, Docket No. UE-150204.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
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.	Wyoming Industrial Energy Consumers	Power Cost Deferral
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.	Columbia Rural Electric Association	Customer Direct Access / Customer Choice
In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 296.	Industrial Customers of Northwest Utilities	Power Cost Modeling

In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 294.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
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.	Industrial Customers of Northwest Utilities	Power Cost Deferral
In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction, Or.PUC, Docket No. UM 1712.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
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.	Industrial Customers of Northwest Utilities	Resource Planning
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.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
2016 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-16.	Industrial Customers of Northwest Utilities	Revenue Requirement, Policy
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.	Industrial Customers of Northwest Utilities	Cost of Service
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.	Boise Whitepaper, LLC	Revenue Requirement, Rate Design
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.	Industrial Customers of Northwest Utilities	Power Cost Modeling
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.	Wyoming Industrial Energy Consumers	Power Cost Modeling
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.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design, Power Costs
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.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 287.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 283.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU), Or.PUC, Docket No. UE 286.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment, Or.PUC, Docket No. UE 281.	Industrial Customers of Northwest Utilities	Coal Retirement
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.	Industrial Customers of Northwest Utilities	Customer Direct Access

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 391

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
2022 Annual Power Cost Update Tariff.	)
	)

EXHIBIT AWEC/102

2022 PRODUCTION TAX CREDIT RATE ANALYSIS

PTC Inflation Adjustment Factor Calculations

	Year	GDP Implicit Price Deflator						Inflation Adjustment Factor			PTC
		Q1	Q2	Q3	Q4	AVG.	1992	Recalc'd	Actual	Delta	Rate
	1992	119.80	120.60	121.20	121.80	120.90	120.90	1.0000	1.0000	-	1.5
	1993	123.30	124.00	124.50	124.90	124.20	120.90	1.0273	1.0273	-	1.5
	1994	125.00	125.90	126.50	126.90	126.10	120.90	1.0430	1.0430	-	1.6
	1995	106.70	107.30	107.80	108.30	107.50	100.00	1.0750	1.0750	-	1.6
	1996	109.00	109.50	109.90	110.30	109.70	100.00	1.0970	1.0970	-	1.6
	1997	111.71	112.22	112.62	113.05	112.40	100.00	1.1240	1.1240	-	1.7
	1998	112.32	112.56	112.84	113.04	112.69	100.00	1.1269	1.1269	-	1.7
	1999	103.83	104.19	104.46	104.98	104.37	91.70	1.1382	1.1382	-	1.7
	2000	106.10	106.73	107.15	107.65	106.91	91.84	1.1641	1.1641	-	1.7
	2001	108.65	109.21	109.82	109.75	109.36	91.84	1.1908	1.1908	-	1.8
	2002	110.14	110.48	110.76	111.21	110.65	91.84	1.2048	1.2048	-	1.8
	2003	105.15	105.43	105.85	106.16	105.65	86.39	1.2230	1.2230	-	1.8
	2004	107.25	108.09	108.48	109.06	108.22	86.39	1.2528	1.2528	-	1.9
	2005	110.91	111.62	112.53	113.49	112.14	86.39	1.2981	1.2981	-	1.9
	2006	114.95	115.89	116.42	116.89	116.04	86.39	1.3433	1.3433	-	2
	2007	118.75	119.52	119.83	120.61	119.68	86.39	1.3854	1.3854	-	2.1
	2008	121.51	121.89	123.06	123.21	122.42	86.39	1.4171	1.4171	-	2.1
	2009	109.69	109.69	109.78	109.88	109.76	76.53	1.4342	1.4342	-	2.2
	2010	109.95	110.49	111.05	111.15	110.66	76.53	1.4459	1.4459	-	2.2
	2011	112.40	113.12	113.84	114.08	113.36	76.60	1.4799	1.4799	-	2.2
	2012	114.60	115.04	115.81	116.07	115.38	76.60	1.5063	1.5063	-	2.3
	2013	106.11	106.26	106.78	107.20	106.59	70.64	1.5088	1.5088	-	2.3
	2014	107.66	108.23	108.60	108.64	108.28	70.57	1.5344	1.5336	0.00	2.3
	2015	109.10	109.67	110.03	110.29	109.77	70.57	1.5555	1.5556	(0.00)	2.3
	2016	110.63	111.26	111.65	112.21	111.44	70.57	1.5791	1.5792	(0.00)	2.4
	2017	112.75	113.03	113.61	114.27	113.42	70.57	1.6072	1.6072	-	2.4
	2018	109.37	110.27	110.68	111.22	110.38	67.33	1.6396	1.6396	-	2.5
	2019	111.47	112.19	112.66	113.04	112.34	67.33	1.6686	1.6687	(0.00)	2.5
	2020	113.42	112.82	113.84	114.37	113.63	67.33	1.6877	1.6878	(0.00)	2.5
Zero Inflation	2021	115.514	*115.514*	*115.514*	*115.514*	115.514	67.325	1.7158			***2.6***
			0%	*0%*	*0%*						
3 Qtr. Deflation	2021	115.514	*114.8006*	*114.0917*	*113.3871*	114.4484	67.325	1.6999			***2.5***
Needed for 2.5¢			***-0.62%***	***-0.62%***	***-0.62%***						
2 Qtr. Deflation	2021	115.514	*115.514*	*114.0874*	*112.6784*	114.4485	67.325	1.6999			***2.5***
Needed for 2.5¢			*0%*	***-1.24%***	***-1.24%***						

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 391

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
2022 Annual Power Cost Update Tariff.	)
	)

EXHIBIT AWEC/103

COB MARGIN ANALYSIS

(REDACTED)

Exhibit AWEC/103 contains Protected Information Subject to Protective Order No. 21-099 and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 391

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
2022 Annual Power Cost Update Tariff.	)
	)

EXHIBIT AWEC/104

AVANGRID CAPACITY CONTRACT ANALYSIS

(REDACTED)

Exhibit AWEC/104 contains Protected Information Subject to Protective Order No. 21-099 and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 391

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
2022 Annual Power Cost Update Tariff (Schedule 125).	)

OPENING TESTIMONY OF

LANCE D. KAUFMAN, PH.D.

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

June 30, 2021

TABLE OF CONTENTS

EXHIBIT LIST

AWEC/201 – Curriculum Vitae of Lance D. Kaufman

Confidential AWEC/202 – PGE Responses to Data Requests

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance Kaufman. I am the principal economist for the consulting firm Aegis Insight. I have extensive experience with regulated utilities in the Western United States. My witness qualification statement can be found at Exhibit AWEC/201.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from Portland General Electric ("PGE")

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This testimony presents my initial review of PGE's proposed Annual Update Tariff ("AUT"), including Net Variable Power Costs ("NVPC"), for calendar year 2022. I reviewed several key modeling changes proposed by PGE in this case, including those related to Lydia Hourly Price Shaping Model Update ("Lydia 2.0") and Western Energy Imbalance ("EIM") benefits.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations are summarized in Table 1, below, followed by brief descriptions of each issue.

Table 1: Kaufman Adjustments

		NVPC Impact ($000)
1	Exclude Lydia 2.0	($5,614)
2	Exclude Gas Optimization Refinements	($1,823)
3	EIM Benefit Adjustment	($742)
4	Total	**($8,179)**

LYDIA 2.0: Lydia 2.0 over represents the relationship between wind and prices. I recommend excluding the Lydia 2.0 model change based on the timing of the filing and flaws with the model changes.

EXCLUDE GAS OPTIMIZATION REFINEMENTS: PGE represents significant changes to gas optimization modeling as refinements rather than enhancements. I recommend treating these changes as enhancements and excluding based on the timing of PGE's filing.

EIM BENEFITS: PGE underestimates EIM benefits by excluding high volume EIM transactions from historic data. I recommend including all transactions and not allowing offsets within resource types.

BEAVER PLANT CONVERSION: PGE proposes converting the Beaver Plant from dual fuel to natural gas only. This will reduce PGE's system reliability. No adjustment is proposed.

II. UNWARRANTED MODELING CHANGES

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH PGE'S MODELING CHANGES.

A. PGE proposes numerous modeling changes in this filing. PGE acknowledges that it is prohibited from making such changes outside of a general rate case.[1/] PGE has indicated that it plans to file a general rate case this year;[2/] however, PGE's general rate case filing is too late to qualify this year's AUT for modeling changes. Furthermore, PGE's modeling changes are one-sided and will make the NVPC forecast less accurate, not more accurate.

In this section first discuss modeling and model accuracy in general and I evaluate PGE's historic NVPC forecast model accuracy. I show that PGE has historically over-forecasted net power costs. The modeling changes proposed by PGE increase the NVPC

[1/] See Exh. AWEC/202 at 2-3 (PGE Response to AWEC DR 008) ("Should PGE decide not to file a 2022 general rate case, PGE would withdraw the following model enhancements: Lydia Hourly Price Shaping Model Update; Gas Storage Optimization Enhancements; Pacific Northwest Coordination Agreement Study; Beaver Plant Upgrade…Faraday Hydro Coefficient Update... In addition to the modeling enhancements mentioned above, PGE would also withdraw the enhancements applied to the thermal plant parameters included in the initial model step log, Steps 00g through 00k.").

[2/] Docket No. UE 391 PGE/100 Vhora – Outama – Batzler at 9:14; Exh. AWEC/202 at 4 (PGE Response to AWEC DR 008, Attachment 008-A CONF).

forecast. Modeling changes that tend to increase the NVPC forecast will increase PGE's average forecast error and thus make the forecast less accurate. I then provide background on timing of the AUT filing, background on AUT modeling changes, and show that PGE failed to file the AUT in time to propose modeling changes and that therefore the modeling changes should be rejected.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE TIMING OF THE AUT FILING.

A. I recommend that the Commission reject each of the modeling changes PGE has proposed in this filing because PGE has not complied with the Minimum Filing Requirements ("MFRs") set forth in Docket No. UE 198, Order No. 08-505. PGE filed the AUT with proposed modeling changes on April 1, 2021.[3/] PGE should have filed the AUT with proposed modeling changes on February 28, 2021. PGE failed to file the AUT in time to propose modeling changes and therefore the modeling changes should be rejected.

Q. WHAT IS THE BASIS THAT THE COMMISSION SHOULD USE TO JUDGE NVPC FORECAST AND PROPOSED MODEL CHANGES?

A. The Commission should evaluate NVPC with the general goal of establishing an accurate and precise forecast under normal conditions. The Commission should temper accuracy and precision with other regulatory considerations such as prudency and transparency.

Accuracy means that absent abnormal events, such as the 2019 NW Pipeline outage, the average deviation between forecast and actual NVPC will be close to zero. Precision means that absent abnormal events, NVPC deviations fall within a small range.

[3/] Docket No. UE 391 PGE/100 Vhora – Outama – Batzler at 3:18, 8:10-9:2.

Regulatory considerations may warrant reductions in a forecast's accuracy. For example, adjustments are made to PacifiCorp's NVPC to account for disallowed investments or other imprudent costs.[4/] Such adjustments often reduce the forecast accuracy.

Q. HOW ACCURATE HAS PGE'S NVPC FORECAST BEEN OVER THE LAST TEN YEARS?

A. PGE tends to over-forecast NVPC. The table below summarizes PGE's NVPC deviation (actual minus forecast) by month from January 2011 to December 2020. The average NVPC deviation is $5.6 million. The two outlying data points that are highlighted – August 2017 and February 2019 – are more than three standard deviations from the mean.

Table 2: Net Power Cost Forecast Is Typically Higher Than Actuals

	Janurary	February	March	April	May	June	July	August	September	October	November	December	Total
2011	$ (4,954)	$ (5,829)	$ (8,634)	$ (4,426)	$ (3,734)	$ (1,238)	$ (4,786)	$ (3,701)	$ 831	$ 2,396	$ (1,256)	$ 818	$ (34,256)
2012	413	10	(5,707)	(163)	(2,401)	(2,065)	(1,542)	32	(2,608)	1,329	284	(4,463)	(16,929)
2013	(2,428)	450	1,259	(4,455)	(3,716)	(4,806)	3,798	873	4,224	4,987	1,447	9,483	11,015
2014	1,994	7,262	(12,185)	(2,167)	(4,122)	(4,357)	(721)	4,341	868	1,686	(2,502)	2,164	(7,668)
2015	663	(1,840)	(1,335)	(1,647)	(1,866)	3,884	6,275	1,070	(1,222)	(936)	1,602	(6,416)	(2,601)
2016	2,716	(1,003)	(1,188)	(3,065)	(1,640)	(2,062)	2,842	2,922	(2,995)	1,356	(1,907)	(5,662)	(9,718)
2017	6,326	(314)	(6,849)	(3,703)	(910)	211	(3,482)	16,198	6,287	(1,739)	675	2,084	15,019
2018	311	(8,453)	(3,217)	(4,976)	(4,544)	(6,287)	12,524	9,024	2,214	2,571	(4,533)	3,210	(3,017)
2019	(2,580)	24,606	(9,213)	(2,685)	(4,178)	1,097	1,888	2,073	(5,625)	(7,152)	3,571	2,865	5,432
2020	(6,650)	(2,219)	(6,537)	(4,720)	(3,243)	(6,428)	9,004	4,429	787	(2,324)	4,402	45	(13,737)
Average	(419)	1,267	(5,361)	(3,201)	(3,035)	(2,205)	2,580	3,726	276	218	178	413	(5,646)

The table below replaces the outlying datapoints with the monthly average. This table shows that, absent abnormal events, PGE over-forecasted NVPC in eight of ten years, with an average over forecast of $9.5 million.

[4/] PacifiCorp's net power costs are adjusted to remove Rolling Hills wind and certain avian related wind curtailments.

Table 3: Removing Outliers Increases Forecast Error

	Januray	February	March	April	May	June	July	August	September	October	November	December	Total
2011	$ (4,954)	$ (5,829)	$ (8,634)	$ (4,426)	$ (3,734)	$ (1,238)	$ (4,786)	$ (3,701)	$ 831	$ 2,396	$ (1,256)	$ 818	$ (34,513)
2012	413	10	(5,707)	(163)	(2,401)	(2,065)	(1,542)	32	(2,608)	1,329	284	(4,463)	(16,880)
2013	(2,428)	450	1,259	(4,455)	(3,716)	(4,806)	3,798	873	4,224	4,987	1,447	9,483	11,117
2014	1,994	7,262	(12,185)	(2,167)	(4,122)	(4,357)	(721)	4,341	868	1,686	(2,502)	2,164	(7,739)
2015	663	(1,840)	(1,335)	(1,647)	(1,866)	3,884	6,275	1,070	(1,222)	(936)	1,602	(6,416)	(1,768)
2016	2,716	(1,003)	(1,188)	(3,065)	(1,640)	(2,062)	2,842	2,922	(2,995)	1,356	(1,907)	(5,662)	(9,686)
2017	6,326	(314)	(6,849)	(3,703)	(910)	211	(3,482)	2,340	6,287	(1,739)	675	2,084	927
2018	311	(8,453)	(3,217)	(4,976)	(4,544)	(6,287)	12,524	9,024	2,214	2,571	(4,533)	3,210	(2,154)
2019	(2,580)	(1,326)	(9,213)	(2,685)	(4,178)	1,097	1,888	2,073	(5,625)	(7,152)	3,571	2,865	(21,266)
2020	(6,650)	(2,219)	(6,537)	(4,720)	(3,243)	(6,428)	9,004	4,429	787	(2,324)	4,402	45	(13,452)
Average	(419)	(1,326)	(5,361)	(3,201)	(3,035)	(2,205)	2,580	2,340	276	218	178	413	(9,541)

PGE's forecast accuracy is sensitive to season. PGE over-forecast April and May in every year, and March and June in most years.

Q. WHAT EFFECT WILL PGE'S PROPOSED MODEL CHANGES HAVE ON PGE'S FORECAST ACCURACY?

A. PGE's proposed model changes increase NVPC forecast, and thus also increase PGE's forecast error.

Q. DOES REPLICATING UNDERLYING MARKET MECHANICS JUSTIFY HAVING DECREASED FORECAST ACCURACY?

A. No. Models are by nature simplified representations of reality. It is not feasible to produce a model that accounts for every aspect of market mechanics. The overall accuracy of a forecast is affected by these simplifications. However, it is important to remember that the ultimate accuracy of the model is the result of a complex interaction of model simplifications and assumptions.

I illustrate this with the following example. Suppose that production cost is being forecasted, and that the "true" cost relationship is represented by the following formula:

$$Cost(x) = 100x - x^2 + x^3$$

Now suppose that a company has been using the following "simplified" model to estimate cost:

$$Cost_{Estimate\ A}(x) = 100x$$

The simplified model is obviously incorrect, but if only one unit is being produced, it will be accurate. Now suppose that an engineer researches production costs and discovers that the "x^2" component was missing form the cost model and recommends enhancing the cost model:

$$Cost_{Estimate\ B}(x) = 100x + x^2$$

The error in Estimate A is $-x^2 + x^3$ and the error in Estimate B is x^3. The new model replicates one of the underlying components of cost, but it makes the cost model less accurate.

Table 4: Model Enhancements Can Increase Error

x	Estimate A Error	Estimate B Error
1	0	-1
2	-4	-8
3	-18	-27

Q. ARE YOU SUGGESTING THAT PGE SHOULD NOT ATTEMPT TO IMPROVE ITS NVPC FORECAST MODEL?

A. No. The above example is not intended to dissuade PGE or the Commission from enhancing the NVPC forecast. The example simply illustrates the importance of judging individual model changes within the overall context of the total forecast.

Q. PLEASE EXPLAIN HOW THE COMMISSION SHOULD APPLY THIS CONCEPT TO PGE'S PROPOSED CHANGES.

A. The Commission should first address a threshold question of whether PGE's model changes are appropriate representations of underlying mechanics. The Commission should then determine whether the changes increase the accuracy of the forecast. When addressing the second question of increasing accuracy, it may be appropriate to consider the overall impact of multiple model changes. PGE is currently over-forecasting NVPC. This means that any model enhancements that increase the NVPC forecast, such as Lydia 2.0 should be paired with model enhancements that decrease the forecast, such as refined COB pricing. The Commission should not approve a combination of model changes that increase the overall NVPC forecast.[5/]

Q. WHAT MODELING CHANGES HAS PGE PROPOSED IN THIS FILING?

A. PGE has proposed the following six modeling changes: (1) the Lydia Hourly Price Shaping Model Update ("Lydia 2.0") adjustment; (2) Gas Storage Optimization Enhancements; (3) Pacific Northwest Coordination Agreement Study; (4) Beaver Plant Upgrade; and (5) Faraday Hydro Coefficient Update."[6/]

Lydia 2.0 modifies the within month shapes of wind generation and power process to shift a large amount of wind generation to low price periods. Gas Storage Optimization Enhancements makes changes to dispatch plants gas based on specific sources of gas. Pacific Northwest Coordination Agreement Study relates to inconsistencies that PGE has identified between upstream and downstream water flows from the study. PGE has not yet provided associated model changes and plans to provide the model changes in July.[7/] The Beaver Plant Upgrade relates to PGE's proposed conversion of Beaver from dual fuel to Natural Gas Only generation. The Faraday Hydro Coefficient Update relates to upgrades of the Faraday generators. PGE has not provided the model changes related to the Faraday Hydro Coefficient Update.

In addition to the model changes identified by PGE in PGE Response to AWEC DR 008, PGE made a number of "Refinements" that had a significant impact on the net power cost forecast. These refinements generally relate to the gas storage optimization model.

5/ This advice refers to model changes regarding on-going cost mechanics such as the wind-price relationship. It does not apply to new cost components, such as the Wheatridge PPAs. Because such costs are new costs, accurately modeling them will not exasperate forecast error.

6/ Exh. AWEC/202 at 2-3 (PGE Response to AWEC DR 008).

7/ PGE/100 Vhora – Outama – Batzler / 39.

Q. IS PGE REQUIRED TO FILE THE AUT BY A SPECIFIC DATE IF THE COMPANY PROPOSES MODELING CHANGES IN A GENERAL RATE CASE YEAR?

A. Yes. The Commission adopted MFRs in Docket No. UE 198, Order No. 08-505 that clearly set forth "Delivery Timing" and "Direct Case Filing" requirements applicable to PGE in AUT and GRC filings. According to the MFRs, for "Delivery Timing", an AUT year requires an April 1 initial filing, and a GRC year requires a February 28 initial filing.[8/] Further, "at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:…Modeling Enhancements and New Item Inputs…not applicable in AUT year."[9/] Under "Direct Case Filing", the MFRs specify that the Direct Case Filing applies to a "GRC Initial Filing (e.g. February 28) in a GRC year" whereas a for a non-GRC year, applicable to an AUT Initial Filing, April 1 filing date applies.[10/] PGE is required to file the AUT by February 28th when it proposes modeling changes and only in a year when it files a GRC.

Q. PLEASE EXPLAIN THE MFRs IN MORE DETAIL.

A. As explained above, the Commission adopted MFRs in Docket No. UE 198, Order No. 08-505. In UE 198, Settling Parties filed a Joint Explanatory Brief in support of the power cost stipulation which set forth future filing requirements and explains that "[a]s part of the settlement of power costs, the Parties discussed some possible process improvements to general rate cases and/or Annual Update Tariff filings. As a result, the Parties…agreed to a list of minimum filing requirements ("MFRs") for PGE in [AUT] and general rate case proceedings….It is anticipated that these requirements will lessen the need for data requests, and allow Staff, CUB and ICNU to receive desired information sooner than they would

8/ Docket No. UE 198, Order No. 08-505, Appendix A at 11 (Oct. 21, 2008).
9/ Id.
10/ Id.

otherwise."[11/] As set forth in Commission Order No. 08-505, the MFRs were agreed to by the Settling Parties "for PGE in future AUT filings and general rate case proceedings."[12/] The MFRs apply to PGE's current AUT filing.

Q. DID PGE PROVIDE ANY INDICATION THAT IT WILL FILE A GRC THIS YEAR?

Yes. The Company states in its Direct Testimony that "PGE is expecting to submit a general rate case filing after the enclosed AUT filing."[13/] The Company further admits that if PGE does not file a GRC, it will withdraw the six proposed modeling enhancements described above.[14/]

Q. WHY DO THE MFRs REQUIRE PGE TO FILE THE AUT BY FEBRUARY 28TH WHEN THE COMPANY PROPOSES MODELING CHANGES AND ONLY IN A YEAR WHEN IT FILES A GRC?

A. PGE is required to file the AUT by February 28th when the Company proposes modeling changes and only in a year when it files a GRC so that parties have sufficient time to review the modeling changes and to limit the potential impact of modeling changes to years in which all of PGE's rates are under investigation. In filing the AUT on April 1st with proposed modeling changes, as PGE has done here, parties do not have adequate time to review the modeling changes and pursue discovery. The AUT must be resolved before PGE calculates its transition adjustments in early November; thus, an April 1st filing significantly compresses the

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11/ Docket No. UE 198, Joint Explanatory Brief in Support of Power Cost Stipulation at 5-6 (July 18, 2008). Industrial Customers of Northwest Utilities ("ICNU") is AWEC's predecessor.

12/ Order No. 08-505 at 3.

13/ Docket No. UE 391, PGE/100 Vhora – Outama – Batzler at 9:14; Exh. AWEC/202 at 4 (PGE Response to AWEC DR 008, Attachment 008-A CONF).

14/ See Exh. AWEC/202 at 2-3 (PGE Response to AWEC DR 008) ("Should PGE decide not to file a 2022 general rate case, PGE would withdraw the following model enhancements: Lydia Hourly Price Shaping Model Update; Gas Storage Optimization Enhancements; Pacific Northwest Coordination Agreement Study; Beaver Plant Upgrade…Faraday Hydro Coefficient Update... In addition to the modeling enhancements mentioned above, PGE would also withdraw the enhancements applied to the thermal plant parameters included in the initial model steplog, Steps 00g through 00k.").

procedural schedule. Here, PGE has proposed several complicated modeling changes and required the parties to perform a full review of these changes in less than three months. This issue is exacerbated for AWEC because AWEC was not allowed to sign the protective order in this proceeding until it was granted intervention as a party, so it was unable to review any confidential information until April 19, 2021.[15]

Q. WHAT IS PGE'S POSITION ON THIS ISSUE?

A. In response to AWEC's data request on this issue, PGE asserts that the MFRs do not in fact require PGE to file a GRC prior to February 28th, "but rather established the [MFRs] to be provided by PGE in conjunction with the Net Variable Power Cost forecast in either a GRC or an [AUT] April 1 initial filing…Because PGE did not submit a 2022 GRC prior to April 1, 2021 but is expecting to submit a 2022 general rate case this year, [PGE] included the items with [its] initial AUT filing."[16] Essentially, PGE argues that the Company need only file the AUT by February 28th if it also files a GRC at that time.

Q. WHY IS PGE'S POSITION ON THE ISSUE INCONSISTANT?

A. PGE's position is inconsistent with Order No. 08-505 because it contradicts a common sense reading of the MFRs set out in Order No. 08-505. According to PGE, the timing of when the Company files a rate case is the determining factor in when it files the AUT, rather than the presence or absence of modeling changes. When PGE files a rate case, however, is unrelated to the fact that the introduction of modeling changes to the AUT dramatically increases the complexity of reviewing PGE's filing. The intent of the MFRs was clearly not to constrain

[15] Docket No. UE 391, Ruling (April 19, 2021).
[16] Exh. AWEC/202 at 1 (PGE Response to AWEC DR No. 007).

PGE to filing GRCs by February 28th of any given year; yet, under PGE's interpretation of the MFRs, it can propose major changes to its power cost model and avoid the procedural requirements of the MFRs, and the customer protections they provide, simply by filing a GRC later in the year. This interpretation effectively reads the timing requirements out of the MFRs.

Q. DO YOU HAVE CONSERNS WITH SPECIFIC MODEL ADJUSTMENTS?

A. I believe the Lydia 2.0 model does not appropriately represent the relationship between wind and price for inclusion in this year's AUT. I am also concerned that PGE's decision to convert Beaver to natural gas may not be prudent. I discuss these issues in separate sections of my testimony below.

PGE has not yet provided details on the Pacific Northwest Coordination Agreement Study and Faraday Hydro Coefficient Update model changes.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission reject Lydia 2.0 as an impermissible model change because PGE failed to file the AUT by February 28th when it proposes modeling changes and only in a year when it files a GRC. Even if the Commission does not reject Lydia 2.0 due to late filing, I continue to recommend that the Lydia 2.0 model change be rejected for my response detailed in Section III. Eliminating Lydia 2.0 reduces NVPC by $5.6 million.

PGE differentiates between Gas Storage Optimization Enhancements and Refinements. PGE did not provide details on the gas storage refinements in the initial filing workpapers and AWEC is continuing to investigate these changes. In particular, AWEC is concerned that the additional restrictions on the Beaver runtime is exasperating the financial impact of the Port Westward Complex gas shortage. I recommend excluding these changes as model changes and therefore impermissible based on the MFRs unless PGE provides sufficient workpapers demonstrating that these changes are appropriately characterized as refinements rather than enhancements. This reduces NVPC by $1,823,000.

I reserve judgement on the Pacific Northwest Coordination Agreement Study and Faraday Hydro Coefficient Update until PGE files these model changes and I have had a chance to review the changes. After PGE files these updates and I have a chance to review them, I may recommend they be excluded due to late filing.

Q. ARE THERE OTHER REASONS WHY THE COMMISSION SHOULD REJECT PGE'S MODELING CHANGES IN THIS YEAR'S AUT?

A. Yes, as noted above model changes that increase NVPC will increase PGE's historic forecast error. PGE's modeling changes in this case increase the NVPC forecast overall, which is likely to make this forecast less accurate based on historical data.

Q. IS AWEC WILLING TO CONSIDER PGE'S PROPOSED MODEL CHANGES IN FUTURE CASES?

A. Yes, if PGE does file a GRC, then because the procedural schedule for that GRC will extend into next year, AWEC would not oppose PGE including its proposed modeling changes in next year's AUT, if it files the AUT by February 28, 2022.

III. LYDIA 2.0

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PGE is concerned that previous NVPC forecasts have not correctly accounted for the correlation between wind generation and power prices. PGE proposes a reshaping process to match low wind generation with high market prices and high wind generation with low market prices.[17/] I recommend not adopting Lydia 2.0 because it overestimates the relationship between wind and market prices.

Lydia 2.0 will increase net power costs. The previous section demonstrates that PGE historically over forecasts net power costs. This means that without other offsetting modeling changes Lydia 2.0 will decrease the accuracy of PGE's forecast. If the Commission approves some or all of PGE's Lydia 2.0 model changes, I recommend that the Commission also approve more granular modeling of California-Oregon Border ("COB") transactions, as described in the testimony of AWEC witness Bradley Mullins in AWEC/100 and AWEC/103, to help ensure PGE's power costs remain accurate.

Q. HOW DOES LYDIA 2.0 OVERESTIMATE THE RELATIONSHIP BETWEEN WIND GENERATION AND TIME OF DAY?

A. Lydia 2.0 involves a complex set of normalization and calibration calculations that ultimately results in wind profiles negatively correlated with price profiles. PGE's model forces the majority of wind to be produced during substantially discounted power prices. I believe that the discount PGE applies is much larger than that supported by the data. The table below presents PGE's modified wind and price shapes for July. Note that the price difference between the first week (low wind production) and fourth week (high wind production) is [redacted] MW.

[17/] Docket No. UE 391 / PGE /100 Vhora – Outama – Batzler / 23:7-16.

Table 5: Average Price Variation Unsupported by Regression CONFIDENTIAL

[redacted]

According to Lydia 2.0, low wind production will double Mid-C prices. However, regression modeling does not support PGE's conclusion. Regression modeling of the same data used by PGE to compute Lydia 2.0 prices shows that the maximum price effect of wind in July, i.e., the price impact of going from zero generation to maximum generation, is less than [redacted] per MWh.

Q. HAVE YOU IDENTIFIED ISSUES THAT MAY CONTRIBUTE TO PGE OVERESTIMATING THE RELATIONSHIP BETWEEN WIND AND PRICES?

A. The scope of this proceeding has not been sufficient to identify all the flaws with Lydia 2.0; however, the concerns that I have identified so far include:

1. Ad-hoc modeling. PGE's approach of normalizing and weighting historic data to arrive at wind and price shapes appears to be ad-hoc. PGE creates normalizing factors for both wind and prices by scaling values relative to monthly minimums and maximums across all hours in the month. PGE then averages within hour normalized values by season and hour. This methodology is not derived from analysis, but instead appears to have been developed from the top down.
2. Double counting hourly price shapes. PGE's methodology creates an hourly shape by quartile for wind and prices, then multiplies these values by existing wind and prices that already have hourly shapes. This results in over shaping.

3. PGE does not weight normalized wind or prices when generating the quartile shapes. This means normalized values in each quartile with lower-than-average generation receive the same weight as normalized values in each quartile with higher-than-average generation.

Q. DO YOU AGREE WITH PGE THAT WIND IS NEGATIVELY CORRELATED WITH POWER PRICES?

A. Yes, I agree that wind is negatively correlated with power prices. However, PGE has not shown that Lydia 2.0 models prices and wind in a manner that results in appropriate MONET price and wind inputs. In addition, I am concerned that even if Lydia were modified to create appropriate inputs, it could make MONET less accurate.

Q. WHAT IS YOUR RECOMMENDATION REGARDING LYDIA 2.0?

A. I recommend that the Commission not approve Lydia 2.0. If the Commission does approve Lydia 2.0, I recommend that the model be approved on an interim basis and paired with a more accurate accounting of COB transactions as recommended in AWEC/100 to prevent PGE's net power cost forecast from losing accuracy.

Q. WHAT IS THE IMPACT OF NOT APPROVING LYDIA 2.0?

A. Eliminating Lydia 2.0 reduces net power cost by $5.6 million. However, there is an interaction between Lydia 2.0 model exclusion and AWEC's COB Margin adjustment discussed in AWEC/100.

IV. EIM BENEFITS

Q. PLEASE SUMMARIZE THIS ISSUE.

A. In this filling PGE proposes a modified method of calculating EIM benefits that relies on using historical EIM transactions to model EIM market depth.[18/] PGE excludes historical data that fall outside a certain range. However, the distribution of EIM market transactions is asymmetric and PGE's data exclusions range is symmetric. That results in a larger number of high-volume periods being excluded. I propose removing PGE's data exclusions. This increases EIM benefits by $650,000.

PGE's new methodology also offsets increments with decrements within each 5-minute historic period. This represents the historic volume of EIM increments and decrements. I propose eliminating this offset, which increases the EIM benefit another $93,000.

Q. PLEASE DESCRIBE HOW PGE EXCLUDES HISTORIC DATA.

A. PGE first calculates monthly bounds for increment and decrement volume.[19/] These bounds are calculated separately for increments and decrements and are equal to the first quartile less the 1.5 times the inner quartile range and the third quartile plus the inner quartile range. The table below summarizes PGE's data exclusion bounds for the fifteen-minute market.

[18/] Docket No. UE 391 / PGE / 100 Vhora – Outama – Batzler /28:2-4.
[19/] Docket No. UE 391/ PGE / 100 Vhora – Outama – Batzler / 27-28.

Table 6: Data Exclusions Are Once Sided CONFIDENTIAL

[redacted]

Q. HOW ARE EIM TRANSACTIONS ASYMMETRIC?

A. PGE applies the exclusion bounds to the absolute value of increments and decrements. This means that historic increments and decrements are always greater than zero when testing for exclusion. Note that the lower bound in the table above is nearly always below zero. As a result, PGE almost never excludes records due to the lower bound and nearly all data exclusions are due to the upper bound. This introduces statistical bias to PGE's historic averages.

Q. WHAT OTHER EVIDENCE IS THERE THAT PGE'S DATA EXCLUSIONS INTRODUCE BIAS?

A. When PGE's model is modified to include all data, the average increment and decrement volume increases in every month for both hydro and thermal resources. The table below compares averages with (PGE) and without (AWEC) exclusions. The fact that PGE's methodology decreases volume in every month for both increments and decrements indicates that the method is biased.

Table 7: PGE Data Exclusions Biases Increment and Decrement Limit In Every Period
CONFIDENTIAL

[redacted]

Q. WHAT IS THE IMPACT OF REMOVING PGE'S DATA EXCLUSIONS?

A. Removing PGE's data exclusions increases the EIM benefit estimate by $649,000.

Q. WHAT IS YOUR OTHER ISSUE WITH PGE'S NEW EIM MODELING METHOD.

A. Increments and decrements in the EIM are performed at the plant level but PGE models them at the resource type level. PGE's historic data has periods where one thermal resource is incremented while another thermal resource is decremented within the same period. PGE allows increments and decrements to offset and thus does not account for the benefit of redispatches that offset within resource type.

Q. HOW DO YOU RECOMMEND CORRECTING THIS ISSUE?

A. This issue can be partially corrected by not allowing offsets by the "minority" type of redispatch.

Q. WHAT IS THE "MINORITY" DISPATCH AND HOW DO YOU PREVENT THESE OFFSETS?

A. By "minority" type of dispatch I mean a dispatch in the opposite direction of the net dispatch for the period. For example, if thermal resources have a net increment in a period, but one thermal resource has a small decrement, the decrementing resource is excluded from the increment limit.

Q. ON THE SURFACE IT SOUNDS LIKE YOU ARE PROPOSING A ONE-SIDED EXCLUSION. IS THAT AN ISSUE?

A. Yes. Ideally PGE would give value to all EIM dispatching of resources. By excluding the minority redispatch from benefits I am under estimating EIM benefits. AWEC intends to continue to look at this issue and will explore ways to account for the benefit of the minority dispatch type.

Q. WHAT IS THE IMPACT OF YOUR PROPOSAL?

A. Eliminating offsetting dispatches increases EIM benefit by $93,000. The net EIM benefit increase from both adjustments is $742,000.

V. BEAVER GAS CONVERSION

Q. PLEASE SUMMARIZE THIS ISSUE.

A. The Beaver Plant is currently dual fuel and can be operated with either natural gas or diesel fuel. PGE proposes to convert Beaver units to burn only natural gas. However, the Port Westward complex does not have sufficient gas supply to run all units on natural gas. In addition, these units are subject to pipeline outage risk, such as the recent NW Pipeline outage. During this outage Beaver operated on diesel fuel. Due to the small impact that the conversion has on net power costs in this case, AWEC does not propose a specific adjustment.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 391

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
2022 Annual Power Cost Update Tariff.	)
	)

EXHIBIT AWEC/201

CURRICULUM VITAE OF LANCE D. KAUFMAN

CURRICULUM VITAE

LANCE KAUFMAN
Aegis Insight
4801 W. Yale Ave.
Denver, Colorado 80219
(541) 515-0380
lance@aegisinsight.com

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:

- Cable Huston, LLP, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread and rate design in Cascade Natural Gas Corporation Request for General Rate Revision, Public Utility Commission of Oregon, Docket No. UG 390.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net power costs in Portland General Electric Company 2021 Annual Power Cost Update Tariff, Public Utility Commission of Oregon, Docket No. UE 377.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net power costs in Portland General Electric Company 2021 Annual Update Tariff, Public Utility Commission of Oregon, Docket No. UE 381.
- Davison Van Cleve, PC, Portland, OR 2020

Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread and rate design in Nevada Power Company 2021 General Rate Case, Public Utility Commission of Nevada, Docket No. 20-06003

- Frank & Salahuddin LLC, Denver, Colorado, 2020
  Retained as an expert witness for plaintiffs regarding calculation of lost earnings.
- Level Development Group, LLC, Denver, Colorado, 2020
  Develop real estate valuation model for establishing sale price of newly constructed residential housing.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Jeff Olberg v. Allstate Insurance Company, Case No. C18-0573-JCC, United States District Court, Western District of Washington at Seattle.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Cameron Lundquist v. First National Insurance Company of America, Case No. 18-cv-05301-RJB, United States District Court, Western District of Washington at Tacoma.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2020
  Deposed as expert witness for plaintiff re racial disparities in police use of force re Brandon Washington V. City Of Aurora, Colorado, Case No. 1:19-cv-01160-RM-MEH, United States District Court, District of Colorado.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding coal plant pollution control investments, coal plant decommissioning costs, rate spread and rate design re PacifiCorp 2020 Request for a General Rate Revision, Public Utility Commission of Oregon Docket No. UE 374.
- Davison Van Cleve, PC, Portland, OR and Washington Attorney General, 2020
  Retained as an expert witness for Packaging Company of America and Washington Public Council regarding decommissioning costs and rate design re PacifiCorp 2020 Request for a General Rate Revision, Washington Utility and Transportation Commission.
- Sanger Law, PC, Portland, OR, 2019
  Retained as a consultant for Renewable Energy Coalition and for Northwest & Intermountain Power Producers Coalition to provide analysis of PacifiCorp avoided costs in a Utility PURPA Compliance Filing at the Washington Utility and Transportation Commission Docket, No. UE-190666.
- Sanger Law, PC, Portland, OR, 2019
  Retained as a consultant for Northwest & Intermountain Power Producers Coalition to provide analysis of Portland General Electric avoided costs in support of testimony to the Oregon Legislature.
- Powder River Basin Resource Council, Laramie, Wyoming, 2019.
  Testified as an expert witness for Powder River Basin Resource Council regarding coal plant closures re PacifiCorp 2019 Integrated Resource Plan, Wyoming Public Service Commission Docket No. 90000-147-XI-19.
- The Law Office of Ralph Lamar, Arvada, CO 2019

Deposed as an expert witness for plaintiffs regarding lost profits of a Farmers insurance agency

- Jester, Gibson & Moore, Denver, CO 2019
  Retained as an expert witness for plaintiffs regarding lost earnings in an ADEA wrongful termination matter.
- Albrechta & Coble, Ltd. Fremont, OH 2019
  Retained as an expert witness for plaintiff regarding lost earnings in a race related wrongful termination matter.
- Conrad Law, PC, Salt Lake City, UT 2019
  Retained as an expert witness for Ellis-Hall Consultants, LLC. regarding economic damages in Ellis-Hall Consultants, LLC. et. al. v. George B. Hofmann IV, United States District Court, District of Utah, Central Division.
- Davison Van Cleve, PC, Portland, 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, Portland, OR, 2019
  Testified 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, Portland, 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.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding depreciation rates in re PacifiCorp Application for Authority to Implement Revised Depreciation Rates, Public Utility Commission of Oregon Docket No. UM 1968.
- Davison Van Cleve, PC, Salem, OR and Washington Attorney General, OR 2020
  Retained as an expert witness for Packaging Company of America and Washington Public Council regarding depreciation rates in re Pacific Power 2018 Depreciation Study, Washington Utility and Transportation Commission, Docket No. UE-180778.
- 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.
- 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.

OTHER 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.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 391

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
2022 Annual Power Cost Update Tariff.	)
	)

EXHIBIT AWEC/202

PGE RESPONSES TO DATA REQUESTS

(REDACTED)

May 14, 2021

TO: Corinne Milinovich
Alliance of Western Energy Consumers

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to AWEC Data Request No. 007
Dated April 30, 2021

Request:

Refer to PGE/101 at 1 where it states under "Delivery Timing", "In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing)", and under "Direct Case Filing", "Applies to GRC Initial Filing (e.g. February 28) in a GRC year." Please also refer to PGE/100 at 9:13-18, where it explains the basis for PGE's decision to propose modeling changes in this year's AUT, which is that "PGE is expecting to submit a general rate case filing after the enclosed AUT filing." Please explain why PGE did not file its AUT this year on or before February 28, 2021.

Response:

Commission Order No. 08-505, provided as Exhibit 101, does not prescribe that PGE must file a general rate case (GRC) prior to February 28, but rather established the Minimum Filing Requirements to be provided by PGE in conjunction with the Net Variable Power Cost forecast in either a GRC or an Annual Update Tariff (AUT) April 1 initial filing. The AUT filing date of April 1 was established through Commission Order No. 07-015 in Docket No. UE 180[1] and is reflected in PGE's Schedule 125 language.

Commission Order No. 08-505 provides that "Modeling Enhancement and New Item Inputs" to be submitted with the initial filing of the GRC. Because PGE did not submit a 2022 GRC prior to April 1, 2021 but is expecting to submit a 2022 general rate case this year, we included the items with our initial AUT filing.

[1] See Commission Order 07-015, at page 18-19: [UE 180, FINAL ORDER, 1/12/2007 (state.or.us)]

May 24, 2021

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to AWEC Data Request No. 008
Dated May 10, 2021

Request:

Please refer to PGE / 100, Vhora – Outama – Batzler / 9 at lines 14 to 18.

a. When does PGE expect to file its general rate case?

b. Which of the model enhancements itemized on page 8 does PGE intend to withdraw if PGE decides a general rate case filing is not needed?

Response:

a. See Attachment 008-A.

b. Not all the items listed in Exhibit 100, pages 8-9 are model enhancements. Should PGE decide not to file a 2022 general rate case, PGE would withdraw the following model enhancements:

   - Lydia Hourly Price Shaping Model Update;
   - Gas Storage Optimization Enhancements;
      i. Please note that the Gas Storage Optimization refinements described in PGE Exhibit 100, page 32, lines 11-23 and page 33, lines 1-9 are not modeling enhancements. PGE rather applied refinements and corrections to the gas storage optimization model to ensure alignment with PGE's actual operations and fuel supply capabilities. For the cost impact associated with these refinements please see the initial model step log submitted with PGE's April 1 MFRs, items Ref-01# through Ref-05#.
   - Pacific Northwest Coordination Agreement Study;
      i. PGE did not include the impact of this model enhancement in the initial filing due to an issue PGE uncovered during the validation of the 2019-2020 Headwater Benefits Study. For more details, see PGE Exhibit 100, Section F.2. Should PGE decide not to file a general rate case, PGE would

not make any modeling changes related to the Pacific Northwest Coordination Agreement Study.

- Beaver Plant Upgrade; and
- Faraday Hydro Coefficient Update.

In addition to the modeling enhancements mentioned above, PGE would also withdraw the enhancements applied to the thermal plant parameters included in the initial model step log, Steps 00g through 00k.

Attachment 008-A is protected information subject to Protective Order No. 21-099.

Response to AWEC Data Request No. 008, part a.:

[redacted]