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

TABLE OF CONTENTS

EXHIBIT LIST

AWEC/101 – Qualification Statement of Bradley G. Mullins

AWEC/102 – 2022 Production Tax Credit Rate Analysis

Confidential AWEC/103 –COB Margins Analysis

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.