Portland General Electric
121 SW Salmon Street · Portland, Ore. 97204

July 16, 2019

Vial Email and FedEx

Public Utility Commission of Oregon
Filing Center
201 High Street, SE Ste. 100
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RE: UE 359 Portland General Electric Company's 2020 Annual Power Cost Update Tariff

Attached for filing in the above referenced matter please find the following:

- Reply Testimony of:
  - Mike Niman, Cathy Kim, Greg Batzler (PGE / 300) and Exhibits 301 through 308,
  - Teyent Gossa (PGE / 400) and Exhibits 401 through 405, and
  - Robert Macfarlane (PGE / 500) and Exhibit 501.

Sent via FedEx to the Filing Center:

- Three printed copies of non-confidential Testimony and Exhibits,
- One printed copy of confidential Testimony and Exhibits, and
- One CD containing confidential work papers

Non-confidential work papers have been submitted to puc.workpapers@state.or.us.

Sincerely,

Jay Tinker

Jay Tinker
Director, Rates and Regulatory Affairs

UE 359 / PGE / 300
Niman – Kim – Batzler

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 359

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Mike Niman
Cathy Kim
Greg Batzler

July 16, 2019

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I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis.

My name is Cathy Kim. My position at PGE is General Manager, Power Operations.

My name is Greg Batzler. My position at PGE is Regulatory Consultant, Rates and Regulatory Affairs.

Our qualifications were previously provided in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the positions the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens' Utility Board (CUB) put forward regarding PGE's net variable power cost (NVPC) forecast for 2020.

Q. Please summarize your review of parties' positions.

A. Parties have introduced positions on numerous issues. In almost all instances, parties recommend reductions to PGE's NVPC forecast. As described in more detail below, we largely believe parties' positions are (1) inaccurate, (2) opportunistic in seeking benefits (without recognizing costs or risks), or (3) based on incomplete analysis. Even more concerning, several parties' proposals require modeling changes not allowed in Schedule 125 outside of a general rate case (GRC) proceeding. If implemented in their entirety, parties' recommended reductions would unfairly introduce a significant downward bias on PGE's NVPC forecast, making it highly unlikely PGE would recover its prudently incurred power costs in 2020 under normal conditions.

Q. How does the total amount of parties' proposed adjustments compare to PGE's current NVPC forecast?

A. The combined sum of the adjustments proposed by Staff, CUB, and AWEC total at least $43 million, with some unquantified adjustments likely leading to an even greater amount. This compares to PGE's April 1 forecast of NVPC of approximately $422.0 million, or approximately 10.1% of PGE's 2020 forecasted NVPC.

Q. How does this compare with the recent history of PGE's actual NVPC as reflected through PGE's Power Cost Adjustment Mechanism (PCAM)?

A. Over the last six years of PCAM results, PGE has under collected power costs by a total of approximately $3.0 million and on average by approximately $0.5 million. This demonstrates that, both in total and on average, PGE's forecasted NVPC have been relatively accurate over the last six years and if the Commission approves the Parties' adjustments, PGE will likely under recover its prudently incurred NVPC for 2020.

Q. What is your recommendation regarding the specific issues identified below?

A. With certain exceptions that we discuss below, we recommend the Commission reject AWEC, OPUC Staff's, and CUB's proposed adjustments.

Q. What specific issues do you address in your testimony?

A. We address the following issues raised by parties:

- **California-Oregon Border (COB) Trading Margins (Section II-A)**
- **Wind Capacity Factors (Section II-B)**
- **Gas Optimization (Section II-C)**
- **Boardman Operations (Section II-D)**
- **Qualifying Facilities (Section II-E)**

- **Wholesale Transactions (Section II-F-1)**
- **Standard Inputs (Section II-F-2)**
- **Wheatridge (Section II-F-3)**
- **GTN Pipeline (Section II-F-4)**
- **Inflation Rate in MONET (Section II-F-5)**

Q. How is the remainder of your testimony organized?

A. After this introduction, we have two sections:

- Section II: Parties' Proposed Adjustments
- Section III: Summary and Conclusion

II. Parties' Proposed Adjustments

A. California-Oregon Border (COB) Trading Margins

Q. Please summarize AWEC's and Staff's proposals regarding COB trading margins.

A. AWEC argues that PGE's COB trading margin forecast method understates the margins, because "PGE's methodology aggregates historic data in a manner that masks the value of COB market transactions."[1] AWEC continues to argue that "PGE has not provided evidence that the current method generates an accurate estimate of the benefits PGE obtains from the COB transactions."[2] To support their argument AWEC attempts to calculate an actual margin by using PGE's historical day-ahead COB transactions valued against a Mid-Columbia (Mid-C) hourly real-time price. AWEC, then proposes to adjust PGE's COB margin forecast by the three-year average they calculate. Additionally, both AWEC and Staff argue against PGE including a forecasted transmission derate based on historical BPA derates on the California-Oregon intertie (COI).

Q. Do you agree with AWEC's proposal regarding COB trading margins?

A. No. PGE's current method for forecasting COB margins provides for a <u>normalized</u> and <u>forecasted</u> value that recognizes both seasonality and hourly variability. Additionally, AWEC's analysis is fundamentally flawed in that it compares predominantly day-ahead COB transactions against real-time Mid-C prices. This mixing of markets upwardly biases the value calculated between COB and Mid-C. In fact, when correcting for AWEC's error, the calculated value substantially decreases to a level that is in-line with PGE's forecasted value.

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[1] AWEC/200/page 4 lines 12-13.
[2] AWEC/200/page 4 lines 16-17.

AWEC also fails to recognize the basic principle of MONET, which is to produce a final test year forecast of NVPC that reflects a baseline (or deterministic) forecast of all variables, including sales from PGE's resource portfolio under normal conditions (e.g., plant operations, water and wind flows, and weather). Risks associated with the variables are "frozen" at the final forecast date in November. That is, PGE no longer updates its forecast to reflect changes in the variables that would result in a reduction to (or increase in) costs. PGE's PCAM is designed for this type of activity, and actual changes to sales, purchases, plant dispatch, and any other variable within PGE's NVPC should be considered as part of that process.

Q. You mentioned that AWEC's analysis compares PGE's COB transactions against the wrong Mid-C market. Please elaborate.

A. AWEC uses PGE's historical transactions at COB, which are predominantly made in the day-ahead market, for their comparison to Mid-C prices. However, instead of comparing these COB transactions to day-ahead Mid-C prices, AWEC incorrectly uses hour ahead real-time Mid-C price data, which, on-average, transacts at a lower price. As most of PGE's COB activity is in the form of sales (over 90% from 2016 through 2018), this artificially inflates the value of these transactions. In fact, simply replacing Mid-C real-time prices with Mid-C day-ahead prices reduces AWEC's calculation of the value of PGE's transactions considerably, putting them in-line with PGE's normalized forecast. When removing the atypical purchase value for 2018, the three-year average of purchases and sales at COB using day-ahead is approximately $11 million, before accounting for any transactional costs, or any differences between MONET's normalized environment (normal weather, load, etc.), and real-world conditions within which PGE must operate.

Q. Why do you propose removing 2018 purchases from your comparison of COB actuals versus Mid-C day-ahead prices?

A. From both a volumetric and price perspective 2018 purchase data is an outlier year. For both 2016 and 2017, regardless of which Mid-C market they are compared against, the purchase volumes were not only substantially lower but more importantly, the total purchase value is negative when compared to Mid-C settled prices.

Q. AWEC cites increasing renewable generation in California as leading to increased purchases at COB. Is this why PGE experienced increased volume and value in purchases from California in 2018?

A. No. California has seen high levels of solar penetration for a number of years now and this has had little effect on PGE's strategies around COB purchases. For 2018, as summarized in Table 1 below, over half of these purchases occurred in July and August, with October through December accounting for much of the remaining volume. This coincides with periods when the Pacific Northwest and PGE was resource constrained due to higher loads, restricted generation, and supply disruptions. In fact, access to the California market provided PGE's customers with additional supply during this period.

Table 1 - 2018 COB Purchase Volumes

Month	MWh
January	483
February	7,238
March	598
April	1,910
May	1,368
June	1,539
July	109,076
August	118,059
September	75,983
October	45,524
November	44,613
December	42,891

Q. Please provide an example.

A. During August 2018, PGE's Boardman plant was forced off line for approximately five days due to a steam tube leak and Colstrip experienced a maintenance deration due to emissions issues. Boardman's capacity factor for August was only 62% (compared to 86% forecast in MONET), while Colstrip Units 3 and 4 had a combined capacity factor of just 43% (compared to 93% forecast in MONET). Coinciding with these events, Portland experienced temperatures at the beginning of August at or above 90 degrees for six consecutive days, with daily load peaking at 580 average megawatts (MWa) above the forecasted load used in PGE's 2018 NVPC proceeding.

July presents a similar pattern, with Colstrip units 3 and 4 experiencing a combined capacity factor of just 20% (compared to 93% forecast in MONET), temperatures reaching 90 degrees or above for 15 out of 31 days, and daily load peaking at 570 MWa above the forecasted load used in PGE's 2018 NVPC proceeding. The average load for the entire month of July was 180 MWa above PGE's forecast. Additionally, during most of Q4 2018, PGE's Port Westward 1, Port Westward 2, and Beaver plants (over 1000 MW of generation in total) were unable to dispatch due to gas supply issues resulting from the Enbridge pipeline disruption previously discussed in PGE Exhibit 100 and elsewhere.

During these events, PGE employed numerous strategies in order to reliably serve load. Access to the California market and PGE's ability to utilize the California-Oregon Intertie (COI) assisted with our reliability efforts during these periods. The reason why a comparison of PGE's COB purchase transactions against a settled Mid-C price calculates such a high amount of value in 2018 is due to an extremely elevated Mid-C price due to supply and demand in the region, <u>not</u> depressed prices at COB due to abundant solar production. In fact, Mid-C day-ahead prices were extremely elevated during July and August reaching up to $300 per MWh for a settled daily average. The fourth quarter of 2018, while less severe, presents a similar pattern, with prices spiking up to a settled daily average of over $100 per MWh in the day-ahead Mid-C market. The simple fact is that PGE was not buying power at COB and selling at Mid-C during these peak events.

In summary, the examples above illustrate how PGE can use its access to California markets to manage power supply risk. Additionally, the examples highlight a distinction in PGE's methods of using access to California to manage risk that a simple review of historical prices would miss. This is further illustrated by the fact that performing the same margin calculation on purchases for both 2016 and 2017 calculates a negative value, irrespective of which Mid-C market price is used, highlighting that 2018 is an outlying year due to specific events that skew the historic pricing relationship between COB and Mid-C.

Q. You also mention that transactional costs and differences between MONET's normalized environment (normal weather, load, etc.), and real-world conditions within which PGE must operate should be factored in. Please explain.

A. Through the use of a set of average historical volumes against a forward price curve, consistent with the price curve used in MONET, PGE's forecasting model for COB margins provides a relatively consistent and normalized forecast. However, when simply looking at actuals by hour in isolation, as is true for many of PGE's other power costs in isolation, you see non-normalized results that are affected by PGE's load deviations, weather deviations, and PGE's overall response to a constantly changing set of real-world conditions. As such, the effect on power costs from these changes is appropriately handled through the PCAM.

PGE also incurs transactional costs primarily on purchases that are not included in any of the data and are not forecast within MONET. When PGE exports energy from California to Oregon, we are subject to a Wheeling Access Charge (WAC), which is a flat fee (it does not update very frequently) and uplift costs for ancillary services, congestions, line losses, and other factors, which tend to vary by month depending on the congestion conditions. For 2018, the WAC was $11.47 per MWh, while the uplift costs tended to vary between $0.50 to $1.00 per MWh. While PGE does not propose at this time to include these costs within our forecast method, we feel it is important to note that they exist.

In summary, the costs and conditions that PGE faces and must respond to when managing actual NVPC can vary significantly from what is included within a normalized forecast environment. As such, looking at calculated actual amounts in isolation will never exactly match what a reasonable forecast should be.

Q. AWEC also argues that PGE's forecast method underestimates volumes used. How does PGE respond to this argument?

A. AWEC is correct that PGE's method for calculating trades only includes one purchase or sale per trade, based on which direction the margin generates a positive value. However, what AWEC neglects to recognize is that PGE's forecast fundamentally differs from actual trades made at COB. PGE's forecasted trades <u>only</u> produce a benefit and <u>never</u> a loss. This is not the case when looking at actual COB purchases and sales against a Mid-C day-ahead price. In fact, from 2016 through 2018 on average, when comparing PGE's COB data to a settled day-ahead Mid-C price, a "loss" is calculated on over 440,000 of the MWh actually traded. Removing these volumes from PGE's three-year average MWh volumes of approximately 2.1

million, results in approximately 1.7 million MWh,[3] which is in line with the approximate 1.5 million of volumes PGE transacts on within its forecasted method.

Q. Both AWEC and Staff also take issue with PGE's inclusion of a transmission derate based on average historical data. How does PGE respond to their argument against including this within PGE's COB forecast?

A. PGE generally agrees that historical derates are captured within the trading volumes PGE uses for the COB margin forecast. However, what is not included is any additional short-term purchases on the California-Oregon Intertie (COI) that PGE must incur to move energy down to COB. However, upon further investigation into these purchases, PGE recognizes that neither the volume nor cost is substantial (just over $90k in 2018), and thus we are willing to absorb these costs and forgo the inclusion of a transmission derate within our forecast methodology.

Q. Do AWEC and Staff raise any other issues regarding COB margins?

A. Yes. Both AWEC and Staff have concerns regarding PGE's investigation into methods for increasing the granularity and improving the modeling of COB margins pursuant to the stipulation approved through Commission Order No. 18-405.[4]

Q. How does PGE respond?

A. We recognize that perhaps more could have been discussed in our initial testimony regarding this topic and appreciate Staff including PGE's analysis and discussions around this topic within Staff Exhibit 203. To recap, PGE's current method includes 24 separate purchases or sales for each month, resulting in a forecast method using 288 different data points for both

[3] See PGE Exhibit 305.
[4] Commission Order No. 18-405, Appendix A, page 2.

purchases and sales (i.e., 12x24). Key objectives of this modeling, per Commission Order No. 17-384, were to use a method that is more granular and forward-looking. PGE's current method accomplishes both of these objectives, while AWEC's proposed method is not forward looking. PGE's current method also shapes 24 separate monthly forward market prices for COB into an hourly curve that can be compared on a consistent basis with PGE's hourly Mid-C curve used in MONET. This method results in a margin that is consistent in granularity to other components within MONET, capturing the effects of sales and purchases at COB, while accounting for both hourly and seasonal variations in volume and price.

Q. What other methods did PGE explore?

A. PGE primarily explored two additional methods and found that both produced very similar results yet required more work to produce and were more prone to error. First, PGE attempted to expand its 12 by 24 method (i.e., hourly prices for each month of the year) to a 52 by 24 method (i.e., hourly prices for each week of the year). The time involved in updating to this method increased substantially and with the expansion from 288 different data points to 1,248 (i.e., 52x24) the time involved in validating the results and the risk of error also substantially increased.

Q. Did this method materially change the value calculated?

A. No. The results from this method were consistent with results produced from the current 12 by 24 method. Staff provided the preliminary results of this method within Staff Exhibit 203.

Q. Please describe the other method PGE looked at and the results produced.

A. PGE also attempted to explore a spread option model with modeling software used by power traders to quickly evaluate energy trades in real time. The spread option was modeled as an hourly spread put option for approximately 296 MW of north to south power with no line losses for 1/1/2019 through 12/31/2019. The prices, volatilities, correlation methodology, and data sources used were input in a manner consistent with what is used for PGE's audited financial filings. The value produced from this ranged from slightly lower to slightly higher than PGE's current method depending on the date of valuation. Additionally, the method was less granular and was produced within a software tool that is effectively a "black box". As such, after a preliminary result and prior to spending additional time on a full validation and on making refinements to the volumes and other factors, PGE chose to discontinue its investigation into this method.

Q. Please summarize PGE's response to AWEC's proposed adjustment.

A. AWEC first raised this issue in Docket No. UE 294, PGE's 2016 GRC proceeding. In their testimony, AWEC put forth their estimate of what a three-year average of trading values produced and used this as the basis for their COB trading margins adjustment. Since that time PGE has agreed to include and made multiple refinements to its COB trading margins forecasting method. Now, with AWEC's current argument and margin estimate again using three years of actuals, we have come full circle. However, after correcting for AWEC's mistakes in their method, PGE has shown that our 2020 forecast is now quite comparable to actual results when adjusting for costs that are not included and for some degree of normalization consistent with power costs forecasted within MONET. As such, PGE stands by its method for forecasting COB trading margins. PGE's method relies on actual trading activity, forward trading curves, and a consistent methodology that is shown to produce forecasted results that are comparable to actuals.

B. Wind Resource Capacity Factor

Q. Please summarize the wind resource capacity factor issue put forth by AWEC and Staff.

A. Both Staff and AWEC argue that PGE change its current method of using a five-year rolling average for wind capacity factors to the use of a blend between the original RFP estimate and actuals in developing a forecast. Alternatively, Staff's secondary proposal is to expand PGE's current rolling average method from five years to ten.

Q. Do you agree with Staff's and AWEC's arguments for proposing a change to the method used for modeling PGE's wind resource capacity factors?

A. No. Staff and AWEC rely on justifications, which are misleading and/or incorrect in order to support making a modeling change that will not result in a more accurate NVPC forecast or improved ratemaking and which borders on retroactive ratemaking.

Q. Staff and AWEC both seem to be arguing for PGE to make a modeling change in MONET. Does Schedule 125 allow for modeling changes?

A. No. Schedule 125 specifically states that, outside of the updates indicated in the tariff, "(n)o other changes or updates will be made in the annual filings under this schedule."[5] This is further supported by the minimum filing requirements agreed upon by parties and approved through Commission Order No. 08-505, which state that modeling enhancements and new item inputs are not applicable in an AUT year. The past two years that this issue has been raised have been within a GRC proceeding. However, the 2020 NVPC is being updated through PGE's Schedule 125 tariff, which clearly defines the parameters of what can and cannot be included, based on prior Commission orders and precedent.

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[5] See PGE Exhibit 301 providing PGE Schedule 125.

Q. Does PGE discuss what is allowed under Schedule 125 anywhere else in this docket?

A. Yes. In PGE Exhibit 100, Section III, page 7, PGE clearly lists the updates allowed under Schedule 125, of which, updating "(w)ind energy forecast based on a five-year rolling average" is included.

Q. Have parties argued against PGE including modeling changes outside of a GRC proceeding in the past?

A. Yes. Prior to the adoption of Schedule 125, which clearly defines update parameters, several proceedings included testimony in which parties argued the issue of including modeling changes outside of a GRC. CUB, in particular, argued in Docket No. UE 149 that the Commission should reject the annual process of "enhancing" MONET[6] and in Docket No. UE 180 that "modeling updates were inappropriate for the RVM process."[7][8] Commission Order No. 07-015 issued in Docket No. UE 180 provides that "modeling changes or updates could be considered, not in the Annual Update process, but in a separate docket."

Q. Notwithstanding the fact that modeling changes are precluded from AUT updates, what is the basis of Staff's and AWEC's adjustment?

A. Staff argues that their 50/50 approach for splitting RFP forecasts and actual results is the best way to share wind generation risk and that when only actuals are used in power cost filings, utility owned projects receive an unfair advantage within the RFP process.[9] Staff continues by stating that within the current construct third-party bids must account for generation risk in their bids and that PGE ownership bids do not.[10] Staff further rationalizes their approach

[6] Docket No. UE 149, CUB Exhibit 100.
[7] The RVM, or Resource Valuation Model was the annual power cost update process prior to the Annual Updated Tariff process adopted by the Commission in Docket No. UE 180.
[8] Docket No. 180, CUB Exhibit 200.
[9] OPUC Staff Exhibit 100, page 7.
[10] Ibid.

by stating that their method will help to incent PGE to incorporate generation risk into their bids in future competitive bidding processes.

AWEC bases their adjustment on a similar construct. AWEC argues that using the current five-year average is unfair because PGE sees all the benefits of equity returns, while customers bear all the risks of investments failing to materialize at a level originally forecast.

Q. Staff and AWEC suggest that PGE customers have borne all the risks (and associated costs) of lower than forecast capacity factors. Are they correct?

A. No. When PGE's wind assets under-produce relative to forecasts, PGE incurs the cost of higher priced replacement energy and the cost related to the under-production of federal Production Tax Credits (PTCs). Since 2008, the lost energy of actual wind generation relative to forecast has cost PGE (and its shareholders) an estimated $44.4 million,[11] while the lost value of PTCs in actual results relative to the benefit provided to customers has cost PGE approximately $38.4 million.[12]

Q. When did PGE change from the wind capacity factors originally forecast for Biglow 1, 2, and 3 to the current five-year average method?

A. PGE proposed the change to the more accurate method in Docket No. UE 262, PGE's 2014 General Rate Case.[13] In support of this change, PGE stated the following:

> "A forecast based on actuals is fair, transparent, reflects changing operational experiences, incorporates the effects of recent environmental conditions, is not tied solely to outdated forecasting techniques, and is consistent with other aspects of PGE's

[11] PGE Exhibit 302 provides the cost related to lost energy of actual wind generation relative to forecast.
[12] PGE Exhibit 303 provides historical PTC actuals compared forecast between 2007 and 2018.
[13] After the initial filing of Docket No. UE 262, the NVPC portion of the case was subsequently bifurcated and docketed as Docket No. UE 266.

power cost forecast where actuals serve as the basis for the forecasted value (e.g., thermal forced outage rates, generation under certain wind PPAs (Klondike II), and the BPA imbalance premium)."[14]

Q. What was Staff's response to PGE's methodology change?

A. In UE 266 Staff Exhibit 100, Staff summarized a number of PGE's proposed changes and updates to 2014 NVPC, including "the use of a five-year rolling average when forecasting wind energy,"[15] followed by the statement that "Staff considers the above changes and updates reasonable."[16]

Q. Did any other party appear to take issue with PGE's modelling change to a five-year average for wind energy?

A. No. No other party, including AWEC's predecessor the Industrial Customers' of Northwest Utilities (ICNU), provided testimony regarding this modeling change, and prices for PGE's 2014 NVPC that included this approach were subsequently approved through Commission Order No. 13-280.

Q. Do Staff's or AWEC's proposals result in a better forecast of PGE's wind resources?

A. No. Staff's primary proposal and AWEC's proposal are strictly punitive in nature. They create forecasts of wind energy that are not directly tied to the operational characteristics of the plants either from a historical actuals standpoint or from a forecasted energy standpoint.

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[14] Docket No. UE 262, PGE Exhibit 400, page 10.
[15] Docket No. UE 266 Staff Exhibit 100, page 3, line 8.
[16] Ibid, page 4, line 1.

Q. Does PGE need an additional incentive to ensure accurate wind capacity factors are forecast in a competitive bidding environment as Staff and AWEC suggest?

A. No. Not only is this argument misplaced within an AUT setting, where no new wind generating assets are being requested for inclusion into PGE customer prices, PGE is already incentivized to accurately forecast wind capacity factors. As mentioned above, when PGE's wind resources under-generate relative to forecasts, PGE must make up the difference with more costly power, and is at greater risk of under collecting PTCs both on an annual basis and over the life of the project. Therefore, under-generation, relative to original forecasts leads to higher costs for PGE. With the original capacity factor contributing to the first five years of PGE's forecasted wind production, PGE must absorb any differences between forecast and actual PTC production.

Q. You mention that Staff's and AWEC's proposals are punitive. Please explain.

A. Staff and AWEC are proposing to make changes to PGE's wind forecast for its existing wind generators based on capacity factors estimated and reviewed over 10 years ago in some cases. Neither PGE, nor anyone else can go back in time and adjust any outcome from prior RFPs. Additionally, every resource evaluated in those prior proceedings was evaluated using the best available information <u>at that time</u>. Imposing Staff's or AWEC's proposal on PGE's existing wind resources will not serve to improve capacity factors estimated within the RFP process. These proposals are punitive and will unfairly adjust PGE's wind forecasts to be unreasonable and unlikely to occur.

Q. Please describe the current process for reviewing wind capacity factors through the competitive bidding process.

A. As part of Commission Order No. 13-204 (Docket No. UM 1182), the OPUC stated that:

> "(to) ensure that wind capacity factors are being examined on an equal basis during bid evaluation, we adopt the utilities' proposal to use a qualified and independent third-party technical expert to review the expected wind capacity factor associated with each project on the short list, including benchmark resources. We conclude that this will best achieve the goal of ensuring that all resources are compared fairly in the RFP process."[17]

The above Commission statement is now codified through OAR 860-089-0400(5)(a), which states: "(t)he electric company must use a qualified and independent third-party expert to review site-specific critical performance factors for wind and solar resources on the initial shortlist before modeling the effects of such resources."

Q. Has PGE used a qualified and independent third-party expert to review expected wind capacity factors within any of its Requests for Proposals (RFP)?

A. Yes. During the RFP process that resulted in the selection of Tucannon River Wind Farm and in PGE's most recent RFP, which resulted in the selection of Wheatridge Renewable Energy Facility (Wheatridge), a qualified independent industry expert was used to review the wind assessments of all short-listed wind offers and to provide recommended capacity factor adjustments. Therefore, even if PGE (or any other bidder) were to somehow increase or decrease a wind forecast, purposefully or not, all resources are adjusted up, or down, based on the analysis of an impartial expert in the field.

Q. Is it possible for PGE to incorporate more generation risk into ownership bids, as Staff suggests?

[17] Commission Order No. 13-204, pages 10-11.

A. It is unclear to PGE how Staff assumes PGE could incorporate more risk into an ownership bid. For ownership bids within an RFP, PGE simply identifies resource costs (i.e., a cost-based bid) and includes a return on capital consistent with PGE's approved weighted average cost of capital. PGE has a regulated return on equity (ROE) that cannot be adjusted outside of a GRC and is set to account for the risks associated with a wide variety of investments from long lived distribution assets to higher-risk renewable variable resources. In contrast, third-party developers price their PPA bids to target any return requirement they desire.

Q. To support their argument of PGE having an unfair advantage, Staff states that PGE's recent generation RFPs have primarily resulted in PGE ownership of new resources. Is this statement accurate?

A. Not at all. PGE's most recent procurement efforts (bilateral capacity and renewable RFP) have resulted primarily in contracts. Third-party owned resources account for 85% (580 MW of 680 MW) of the nameplate capacity procured through PGE's recent competitive solicitations.[18]

Q. What other misconceptions are put forth in Staff's and AWEC's testimony on wind capacity factors?

A. Staff suggests that PGE bears none of the PTC risk associated with forecast error. This is incorrect. As we mention above, since 2007, PGE has absorbed over $38 million in costs from PTC risk.

[18] This includes PGE's recent capacity contracts with BPA and Avangrid for 300 MW in total and the Wheatridge Renewable Energy Facility totaling 380 MW of owned and purchased power.

Q. Staff and AWEC seem to suggest that when forecasting wind resources, the resources should be held to assumptions made in their respective RFPs. Is this an argument that parties have ever made for other types of resources?

A. No. Actuals will never match what is forecast to occur. What is important is that, when making a comparison and ranking of resources, you compare them on an equal basis. The competitive bidding process is designed to ensure resources are compared fairly. An independent evaluator (IE) applies oversights and an expert variable energy forecasting specialist specifically analyses and adjusts generation output, to aid in the selection of the best resource.

If Staff's and AWEC's logic were applied to non-renewable RFPs, customers would see power costs much higher than they experience today. Take Port Westward 1 for example. When Port Westward 1 was selected as the winning resource through a competitive bidding process and ultimately included into rates through PGE's 2007 NVPC and general rate case proceedings (Docket Nos. UE 181 and UE 184), gas forward prices were well above $7 per million British Thermal Units (MMBTU) and Port Westward was forecast to be economically displaced for close to three months of the year. Following Staff's and AWEC's argument to its logical conclusion, would have PGE reduce the dispatch of Port Westward 1 by over 100 MWa in the current AUT filing, where it is currently forecast with a capacity factor close to 90%, compared to just over 60% in the 2007 proceedings listed above.

Q. What benefits do customers recognize from PGE owned resources that they do not receive from PPAs?

A. Because customers only pay for the annually updated forecasted costs associated with PGE-owned resources, as opposed to a fixed contract price, they realize the benefits of any reduction in costs PGE can recognize over the life of the project. This is not true under the PPA construct. For example, PGE assumed a certain level of wind integration costs for both Biglow and Tucannon, that are now, due to PGE's ability to self-integrate wind, considerably less. Customers can also recognize the benefits from reductions to operations and maintenance (O&M) costs due to changes in a facility's warranty/service structure. For PPAs such as Vansycle, any reduction of integration or O&M costs will not reduce the cost to customers, but will instead accrue to the developer/operator of the facility.

Q. Does PGE absorb costs related to PPAs under producing relative to forecasts?

A. Yes. Staff incorrectly assumes that PPAs must absorb all risk associated with under-generation. This is incorrect. Renewable PPAs generally do not guarantee generation volumes.[19] As such, the cost of supplying replacement energy and renewable energy certificates for renewable portfolio standard compliance when PPA generation fails to materialize falls largely on PGE. With owned resources, PGE is partially compensated for the risk of under-generation through its equity returns. However, with PPAs, PGE wears some of the risk (and cost) of under-production and yet accrues none of the benefits.

Q. As an alternative to their primary proposal and in an effort to resolve this issue moving forward, Staff also proposes to increase PGE's current five-year forecasting method to ten years. How does PGE respond to Staff's secondary proposal?

A. PGE appreciates Staff's flexibility in seeking to resolve an issue, which they note is being raised for the third year in a row. PGE believes this still falls outside of the updates allowed

[19] If a contract includes damages for under delivery, those damages would only apply to generation levels far below the forecast used in an RFP and power cost proceedings. Such conditions are generally associated with equipment and design failure.

in Schedule 125. However, we are reviewing how this approach might affect new renewable resources, not yet included in customer prices, and are open to further discussion on the issue.

Q. Please summarize PGE's position with respect to Staff's wind adjustment and basis.

A. Both AWEC and Staff propose methods of forecasting wind energy production that will lead to a forecast that is not representative of normal conditions. PGE's current, approved forecasting method of using a rolling five years of generation provides for a more accurate and normalized forecast of wind energy production. Variable resources will undoubtedly generate at quantities that differ from NVPC forecasts, and should the resources generate at levels below forecast, PGE is responsible to replace those deliveries with power from its dispatchable generating resources or from power purchases in the wholesale market, or both. The cost of this replacement power and the cost of lost PTC benefits both intra-year and over the life of PTC generation are borne by PGE shareholders unless the costs are high enough to trigger the PCAM's provisions and PGE's actual ROE is higher than authorized. Therefore, appropriate incentives currently exist (and appropriate processes are in place) for PGE to ensure that capacity factors are accurately calculated within the RFP process.

C. Gas Optimization

Q. What is AWEC's proposed adjustment related to gas optimization?

A. AWEC proposed that PGE include gas optimization margins as an out-of-model adjustment based upon a methodology that AWEC developed and is described below. AWEC's proposed adjustment would reduce PGE's 2020 power cost forecast by approximately $13.1 million.

Q. Is AWEC's proposed modeling change and adjustment allowed in Schedule 125?

A. No. As mentioned on page 13 above, Schedule 125 specifically states that, outside of the updates indicated in the tariff, "(n)o other changes or updates will be made in the annual filings under this schedule."[20] This is further supported by the minimum filing requirements agreed upon by parties and approved through Commission Order No. 08-505, which state that modeling enhancements and new item inputs are not applicable in an AUT year. AWEC's out-of-model adjustment represents a new item input that is beyond the limited scope of an AUT proceeding.

Q. Ignoring the fact that modeling changes and new item inputs are generally precluded from AUT updates, what is the basis of AWEC's adjustment?

A. AWEC argues that PGE's access to extra-regional gas markets and its access to the North Mist Gas Storage facility (North Mist)[21] provide PGE with opportunities to optimize gas activities and produce a significant monetary benefit through purchases and sales between gas hubs.

Q. Do you agree with AWEC's adjustment?

A. No. AWEC's adjustment is based on incorrect assumptions regarding PGE's transportation rights and Stanfield gas market prices. Additionally, their adjustment ignores benefits already modeled in MONET that account for PGE's ability to capture price differentials between the Sumas and Rockies gas markets. We describe our issues with AWEC's adjustment in more detail below.

Q. What are the gas markets that PGE has access to through its gas transportation rights?

A. PGE owns transportation rights on the GTN and Northwest pipelines to access the Sumas, AECO, Rockies, and Stanfield gas hubs. Exhibit 304 provides a map detailing PGE's pipeline

[20] See PGE Schedule 125 provided as PGE Exhibit 301
[21] The North Mist Storage Facility was place in service in May 2019.

and storage rights relative to PGE's gas-fired thermal resources and the gas hubs mentioned above.

Q. What is AWEC's approach to determine a potential gas trading margin?

A. AWEC categorized PGE's potential gas optimization activities into three categories: 1) GTN Pipeline, 2) Northwest Pipeline, and 3) North Mist Storage. PGE will describe in more detail its concerns with AWEC's calculations and proposed adjustment below.

1. GTN Pipeline: AECO - Stanfield trading

Q. What are AWEC's assumptions regarding PGE's ability to trade gas using its transportation rights on the GTN pipeline?

A. AWEC first recognizes that customers do receive a benefit from MONET economically dispatching PGE's Carty and Coyote Springs thermal resources using a forward AECO price, even though Stanfield is physically closer. However, AWEC argues that PGE's transportation rights on the GTN pipeline also allow PGE to monetize the spread between the AECO and Stanfield markets when PGE's Carty and Coyote Spring plants are not running.

Q. How does AWEC calculate their forecasted margin on the GTN pipeline?

A. AWEC first determines the monthly AECO and Stanfield price differential and then multiplies that by the percentage of hours in the month that Carty and Coyote are not forecasted to run. From this, AWEC calculates a benefit of $2.9 million.

Q. Does PGE have concerns with AWEC's method for calculating a GTN pipeline benefit?

A. Yes. AWEC's adjustment is based on incorrect assumptions regarding both the price at Stanfield and PGE's ability to monetize spreads between AECO and Stanfield when Carty and Coyote experience forced outages. Furthermore, AWEC fails to model any constraints on the GTN pipeline, which occur seasonally for maintenance activities.

Q. Please describe the issue with AWEC's Stanfield price forecast.

A. [redacted], [redacted]

Q. Considering these constraints, what is an appropriate method for determining a forward price at Stanfield?

A. [redacted]

Q. Please explain.

A. [redacted]

[22] Operational Flow Orders and Entitlements of receipt and deliver points to balance the system and maintain firm rights of shippers.

[redacted]

Q. Why can't PGE monetize spreads between AECO and Stanfield when Carty and Coyote are in forced outages?

A. PGE cannot monetize spreads between AECO and Stanfield when Carty and Coyote experience a forced outage due to the general undefined duration of forced outage events. During a forced outage PGE maintains the gas transportation capacity for Carty and Coyote to fuel the plants when they return to service.

Q. When does GTN perform maintenance on the GTN pipeline and how does that impact the pipeline capacity?

A. GTN performs maintenance on certain segments of the pipeline between April and November of each year. During the times when maintenance is performed, the pipeline capacity is reduced between three to 15 percent for multiple periods of time that range in duration between one and 14 days, hampering PGE's ability to use its transportation right for trading activities.

Q. Does PGE provide any benefits to customers to reflect the PGE's transportation rights on the GTN Pipeline between AECO and Stanfield gas hubs?

A. Yes, as AWEC acknowledges and we mention above, PGE does currently provide customers with the benefits of forecasting the dispatch of Carty and Coyote Springs in MONET using AECO forward gas prices rather than higher Stanfield gas prices.

2. NW Pipeline: Rockies – Stanfield - Sumas

Q. What are AWEC's assumptions regarding PGE's ability to trade gas using its transportation rights on the Northwest Pipeline?

A. AWEC assumes PGE has the ability to use its transportation rights on the Northwest Pipeline to capture any price differential between the Rockies, Stanfield, and Sumas gas hubs in all hours of the year when PGE's gas plants in the PW/Beaver complex are not running.

Q. What is AWEC's adjustment to PGE's 2020 NVPC forecast related to gas optimization using gas transportation rights on the Northwest Pipeline?

A. AWEC calculates a $5.1 million adjustment to PGE's 2020 NVPC forecast.

Q. Does PGE agree with AWEC's adjustment?

A. No. AWEC's adjustment is based on incorrect assumptions regarding PGE's transportation rights on the Northwest Pipeline and our ability to monetize price spreads between gas hubs. Moreover, AWEC ignores the fact that PGE is already including a gas trading benefit between Rockies and Sumas in the 2020 NVPC forecast.

Q. How does PGE include modeling in MONET to capture price differentials between the Sumas and Rockies gas hubs?

A. PGE's April 1 forecast of 2020 NVPC reduced the 2020 NVPC forecast by approximately $1.2 million from a mark to market adjustment in MONET to reflect the forward price differential between Sumas and Rockies using the 30,000 dekatherms per day (dth/day) firm receipt rights at the Rockies market. This benefit is modeled in MONET as a physical contract based on the Rockies Financial Swap Volumes.[23]

[23] See PGE's April 1, 2020 NVPC initial filing MFRs, Volume 5 – Contracts/Term Contract/Gas Physicals/Rockies Physicals.

Q. Is this benefit recognized in AWEC's testimony or exhibits?

A. No. AWEC does not reference or reflect this customer benefit in their analysis.

Q. Is AWEC's depiction of PGE's transportation rights on the Northwest Pipeline correct?

A. No. AWEC assumes that PGE owns 16,305 dth/day of transportation rights on the Northwest Pipeline from Rockies to Stanfield and another 87,000 dth/day from Stanfield to Sumas, which is not accurate. Although the total daily capacity that AWEC is using is correct, the transportation rights assumed between gas hubs are not.

Q. What are PGE's transportation rights on the Northwest pipeline?

A. PGE holds a total of 103,305 dth/day of firm transportation rights on the Northwest Pipeline that are broken down as follows:

1) PGE holds firm receipt rights at the Sumas, WA / Huntingdon, BC market (Sumas) of 73,305 dth/day that are distributed as follows:
    a. 73,305 dth/day of firm delivery rights on the Northwest Pipeline to the KB pipeline. Of the 73,305 dth/day transportation rights on Northwest Pipeline between Sumas and the KB Pipeline, 11,000 dth/day continue from the KB pipeline to Stanfield but represent non-firm segmented transportation rights (Sumas to Jackson Prairie and Jackson Prairie to Stanfield) that PGE cannot use for arbitrage opportunities between hubs.
2) PGE holds firm receipt rights at the Rockies market of 30,000 dth/day, which already provide forecasted benefits to customers as described above.

Q. Other than the 30,000 dth/day mentioned above, does PGE have any other firm transportation rights that provide the ability to monetize price spreads between gas hubs on the Northwest Pipeline?

A. No. As explained above the remaining 73,305 dth/day of transportation rights on the Northwest Pipeline are either non-firm or exclusively used to fuel the PW/Beaver complex and to deliver gas to the North Mist storage facility.

3. North Mist Storage Facility

Q. What are AWEC's assumptions regarding PGE's ability to use the North Mist for gas trading opportunities?

A. AWEC assumes that PGE can use the North Mist facility to inject gas when the price is low and withdraw to sell at Sumas when it is more expensive. By doing so, AWEC calculates a $5.1 million adjustment to PGE's NVPC forecast.

Q. Do you agree with AWEC's analysis and conclusions?

A. No. AWEC's proposal is based on the incorrect assumption that PGE has the physical ability to withdraw gas from North Mist and sell it at Sumas.

Q. Please briefly describe the North Mist storage facility.

A. North Mist consists of an underground storage facility, including a storage reservoir, along with a 13-mile underground gas pipeline to the PW/Beaver complex, with above ground facilities including a well pad, compressor station and mainline block valve.

The facility is located entirely within Columbia County, Oregon. The gas pipeline originates at North Mist and ends at the Port Westward Industrial Park facilities located approximately five miles north-northeast of Clatskanie, Oregon.

Q. What are the benefits of having gas storage capacity at North Mist?

A. The gas storage services provided by North Mist, in conjunction with PGE's transportation rights on the KB pipeline, meet the fueling requirements of the PW/Beaver complex. To provide flexible capacity, PGE requires a highly flexible and dynamic fuel supply to meet the demands for peaking, load following, and wind integration services. Gas storage withdrawals provide a high degree of intra-day and intra-hour flexibility, which aligns with PGE's need for a flexible and dynamic fuel supply.

Q. Can PGE use the gas at North Mist to generate revenue by purchasing when gas prices are low and selling when gas prices are high?

A. No, PGE does not have the ability to sell gas from North Mist because PGE cannot physically withdraw gas from North Mist to the KB and Northwest pipelines. As noted above, North Mist provides for a unidirectional flow to PGE's PW/Beaver complex.

Q. Please summarize PGE's position with regard to AWEC's proposed gas optimization adjustment.

A. PGE does not agree with AWEC's proposed adjustment because: (1) the gas optimization input is beyond the scope of Schedule 125 annual updates; and (2) AWEC calculates an unrealistic gas optimization adjustment that cannot physically be supported by PGE's actual rights or operations. Also, AWEC ignores the fact that PGE is already modeling in MONET a benefit to customers that reflects PGE's ability to capture the price differentials between the Sumas and Rockies gas hubs.

D. Boardman Operations

Q. Please summarize the parties' proposals regarding Boardman operations in 2020.

A. Parties have the following proposals and recommendations:

OPUC Staff:

1) OPUC Staff expressed its support of PGE's proposal to return to customers any potential benefits realized from running Boardman in Q4 of 2020.
2) OPUC Staff will continue to monitor the status of available coal inventory.

CUB:

1) CUB is opposed to PGE's proposal to defer and return to customers any potential benefits realized from running Boardman in Q4 of 2020. CUB argues that the potential benefit should instead be subject to PCAM deadbands.

AWEC:

1) Boardman Non-Running Station Service (NRSS): Adjust 2020 NVPC forecast by approximately $0.3 million related to removing Boardman NRSS costs in Q4 2020.[24]
2) Boardman Coal Pile: Adjust 2020 NVPC by approximately $0.2 million related to modeling Boardman end-of-year 2019 coal pile in the 2020 Boardman dispatch costs.[25]
3) Boardman Supply Constraints:[26]
    a. Implement plant capacity derates related to Trona supply constraints prior to coal supply constraints.
    b. Implement 100% derates for enough hours to address coal supply constraints.
    c. Perform plant shutdowns in 2019 to build the coal stockpile for 2020.
4) Boardman End of Operations: Allow Boardman to operate in Q4 2020 while the coal supply lasts.

[24] See AWEC Exhibit 100, Section V, pages 18-19.
[25] See AWEC Exhibit 100, Section VI, pages 19-20.
[26] See AWEC Exhibit 200, Section IV, pages 18-21.

Q. What is PGE's position regarding OPUC Staff's and CUB's recommendations.

A. PGE appreciates OPUC Staff's support towards our proposal to return to customers any potential benefits realized from running Boardman in Q4 of 2020. However, we also find CUB's recommendation reasonable.

Q. What is PGE's position regarding AWEC's adjustments and recommendations?

A. PGE largely disagrees with AWEC's proposed adjustments on the basis that they are either unreasonable or require plant parameters modeling changes that are not allowed in Schedule 125. PGE's position regarding each issue that AWEC raised is provided below:

1) Boardman Non-Running Station Services

Q. Please describe AWEC's adjustments related to Boardman NRSS in Q4 2020.

A. AWEC argues that, because PGE is modeling a 100% Boardman derate in Q4 of 2020, Boardman NRSS should rather be considered decommissioning costs and PGE's power cost forecast should be adjusted by approximately $0.3 million.

Q. Does PGE agree with AWEC's adjustment?

A. No. PGE does not believe that costs related to NRSS should be considered decommissioning costs, since these are ongoing O&M costs associated with an in-service asset. Regardless of PGE's forecast, Boardman is expected to be available and in-service until December 31, 2020. As such, if there is coal available on the ground, PGE does plan to operate Boardman to avoid PGE incurring coal removal costs. Consequently, even if PGE is modeling a Q4 100% derate, we still need to maintain the plant's NRSS. Boardman's electric requirements are considered an offset to plant output when the plant is running and, when not, the plant's electric requirements are back fed from the grid at the transmission voltage. Furthermore, AWEC is inconsistent in their approach, with witness Mullins proposing an adjustment to NRSS in

AWEC Exhibit 100 and witness Kaufman recommending in AWEC Exhibit 200 that PGE run Boardman in Q4 2020.

Q. What systems require NRSS when Boardman is not running?

A. When Boardman is not operating, there are various auxiliary systems that need to be energized. These auxiliary systems include but are not limited to: compressed air systems, cooling water systems, HVAC units, plant heating and electrode boiler during colder months, and various lube oil systems for major rotating plant components.

Q. What is PGE's response to AWEC's adjustment related to Boardman NRSS?

A. PGE does not agree that NRSS can be considered decommissioning costs and we do not agree with the adjustment.

2) Boardman Coal Pile

Q. Please describe AWEC's proposed adjustment related to modeling the 2019 coal pile costs within the 2020 Boardman dispatch.

A. AWEC argues that PGE is modeling the cost of dispatching Boardman in 2020 assuming that all of the coal burned in 2020 is acquired from the market when in fact PGE will be starting the year with a coal pile that cost less per ton than the 2020 market rate. By adjusting the coal price for the 2019 coal pile, AWEC is proposing a $213,022 reduction to the 2020 NVPC forecast.

Q. What is the estimated coal pile at the end of 2019 and how does PGE model the coal pile to be supplied to Boardman?

A. PGE's current estimate reflects approximately 183,600 tons remaining in inventory at the end of 2019. PGE is modeling 103,600 tons to be consumed during January 2020 and the remaining 80,000 tons consumed during September 2020. PGE is planning to consume the last 80,000 tons as late as possible to avoid tripping the plant due to the poor quality of the coal recovered from the bottom of the pile.

Q. Do you agree with AWEC's adjustment?

A. Not entirely. AWEC's proposed adjustment only accounts for differences in the coal market price. The total coal cost modeled in MONET, however, includes costs related to emission control chemicals, and rail transportation, and is adjusted by a heat content factor.

Q. How does the adjustment change if all costs related to coal supply are considered?

A. AWEC's adjustment is reduced to approximately $151,000.

3) Boardman Supply Constraints

Q. What are AWEC's concerns related to Boardman supply constraints modeling?

A. AWEC has the following concerns:

a) Implementing the coal derate prior to the Trona derate results in excess coal availability in September 2020. As such, AWEC argues that the derate in September 2020 is not necessary.

b) The derate percentages that PGE applied in Q1 and Q3, 2020 are higher than necessary because PGE assumed Boardman runs at full capacity when not in outage state.

c) In actual operations PGE is more likely to address coal shortage by running the plant at minimum operating capacity or through a full plant shutdown. As such, PGE should model Boardman as fully available within the month and apply 100% derates at the end of each month to address any coal or Trona supply shortages.

d) AWEC argues that PGE should shut down Boardman to build a coal stockpile for parts of 2019 when the plant is less economical to run than in January and February 2020.

Q. What is AWEC's proposal regarding the modeling of coal and Trona derates for 2020 Boardman operations?

A. Although not very clear, AWEC appears to suggest that MONET should model the 2020 Boardman coal and Trona supply-related derates sequentially, based on the month when they are expected to occur. That is, the modeling sequence in MONET should be: (1) derate Boardman in Q1 2020 to reflect coal supply constraints, (2) model the Trona derate in March 2020; and (3) derate Boardman in September 2020 to reflect coal supply constraints.

Q. What is AWEC's expected result from making the modeling change described above?

A. AWEC anticipates that modeling Boardman derates as described above will result in excess coal available for Q3 2020 such that the September 2020 derate will no longer be necessary.

Q. Does PGE agree with AWEC's proposal?

A. PGE agrees that changing the modeling of the Boardman 2020 derates due to coal and Trona supply constraints could result in more coal being available for Q3 2020. However, at this time PGE does not believe AWEC's proposed modeling change is necessary. Market price curves have moved since our April 1 NVPC initial filing making Boardman uneconomical to run in March 2020. Based on current market curves, the September 2020 derate is no longer necessary. Moreover, PGE has received commitment from the Trona supplier for 5,000 tons of Trona and 4,800 tons of sodium bicarbonate (equivalent to 3,000 tons of Trona) to support 2020 operations at Boardman. PGE's July 15 NVPC update reflects market price and Boardman 2020 operation updates.

Q. Do you agree with AWEC's argument that the derate percentages modeled in Q1 and Q3, 2020 are higher than necessary because PGE assumed Boardman runs at full capacity when it is not experiencing an outage?

A. No. The derate percentages modeled in Monet are applied on Boardman expected generation in a normalized environment. Furthermore, AWEC's proposal would require changing the modeling of Boardman parameters in Monet which is an update that is not allowed in Schedule 125.

Q. Do you agree with AWEC's recommendation to model 100% plant shutdowns for blocks of hours to address coal shortages rather than modeling a monthly capacity derate?

A. No. PGE does not believe that the modeling adjustment proposed by AWEC provides a material benefit. Applying 100% derates for blocks of hours to address coal supply shortages only reduces the 2020 NVPC forecast by $27,000, which would be more than offset by the significant plant startup costs (approximately $200,000 per start) expected to be incurred every time the plant is turned back on.

Q. Do you agree with AWEC's recommendation to perform shutdowns at Boardman during 2019 to build the coal stockpile for 2020?

A. Yes. PGE has already shutdown Boardman beginning March 15, 2019 until early July to save coal for December 2019 and January-February 2020. During this period there were times when Boardman would have been economic to operate as market prices exceeded Boardman's dispatch costs.

Q. Is PGE planning to shut Boardman down for any other periods in 2019?

A. Yes. If load and market prices allow it, PGE will perform additional shutdowns at Boardman until the end of 2019. PGE is currently planning to shut down Boardman for various periods of time in September, October, and November 2019.

Q. What are the factors that impact PGE's decisions to run Boardman in order to address coal supply shortages?

A. The driving factors for the decision are: (1) monthly forward power prices; (2) forecast delivery of coal; and (3) the need to have Boardman available in December of 2019 and Q1 of 2020.

Q. How does PGE decide when to run Boardman?

A. PGE evaluates which months Boardman is most economical to be dispatched by analyzing the monthly coal and emission control chemicals stockpiles and expected deliveries, in conjunction with the monthly forward price curves. If PGE determines that there might be insufficient coal to operate the plant in a future high price month, we may shut down the plant to save coal for that month, even if the plant might have been economical to keep running. This evaluation resulted in periods of 2018 and 2019 when the plant was shut down even though the plant would have been economical to run.

Q. How often does PGE evaluate how to dispatch Boardman?

A. PGE performs the evaluation described above at least on a monthly basis when the plant is offline and weekly when the plant is operating. The evaluation process described above follows sound utility practice of utilizing a limited resource during the most valuable periods.

Q. Does PGE agree with AWEC's recommendation that the "Commission should set rates as if PGE had balanced the marginal cost of reserve shutdowns in 2019 and 2020"?

A. No. AWEC's proposal is unclear and speculative and it seems to suggest that PGE can offset any cost increase in 2020 due to coal supply constraints at Boardman with savings resulting from shutting down Boardman in 2019. As described above, PGE evaluates how to run Boardman from a reliability and business economics perspective without any consideration given to the year when it operates. As such, PGE has been treating the July 2018 - December 2020 operating horizon as one long-term optimization problem focused on maximizing the value of the resource while maintaining system reliability.

4. Boardman End of Operations

Q. Please summarize AWEC's concern regarding the modeling of Boardman operations in Q4 of 2020.

A. AWEC is concerned that, as currently modeled, Boardman will have coal available to burn in October 2020, when PGE is applying a 100% capacity derate. To address this concern, AWEC is recommending that PGE limit coal deliveries in Q4 of 2020 but continue to model Boardman running until all coal is consumed.

Q. Is PGE currently modeling any coal deliveries in Q4 2020?

A. No. As stated in PGE Exhibit 100, at page 22, PGE is targeting September 2020 as the last month of available/planned operation and is not planning to purchase any coal or nominate coal transportation, via rails, during Q4, 2020. Placing Boardman on a maintenance outage in Q4 of 2020 reduces the risk of potentially having coal remain on the ground after December 31, 2020, when the plant will cease operations.

Q. Why does AWEC believe that PGE will have coal available to burn in October 2020?

A. AWEC calculates a significant amount of coal remaining in Q4 2020 based on the January 2020 start coal inventory and monthly coal deliveries in 2020, compared to estimated coal consumption at Boardman.[27]

Q. Is AWEC's assumption correct?

A. No. AWEC seems to misunderstand how MONET models Boardman dispatch.

Q. How is Boardman dispatched in MONET?

A. The tranche modeling on the "PC Input" worksheet in MONET shows the maximum amount of coal that PGE could have access to, even during periods when Boardman is not modeled to run. However, the MONET Dynamic Programming is only modeling the purchase and consume of coal when Boardman is economic to dispatch. As such, if Boardman is not dispatched by the Dynamic Programming, MONET does not model these potential coal purchases, although the "PC Input" worksheet in MONET will show the maximum amount that could be supplied. The coal quantity that remains unburned in AWEC's analysis is actually coal that could potentially be purchased and supplied if Boardman was modeled to run in Q4 2020. The filed MONET NVPC does not reflect any costs for purchasing and shipping coal in Q4 of 2020.

Q. Does PGE agree with AWEC's proposal to model Boardman to run in Q4 2020, as long as there is coal available?

A. No. PGE does not currently model any coal to be burned after September 2020. As such, PGE does not model any coal costs in Q4 2020 at Boardman. Modeling Boardman to run in Q4 2020, would require modeling cost related to coal purchases and nominating transportation

[27] See Table 5 in AWEC Exhibit 200, page 23.

during Q4 2020. As described in PGE Exhibit 100, by modeling a 100% Boardman derate in Q4 2020, PGE attempts to minimize the coal quantity remaining in inventory at December 31, 2020. Minimizing the coal quantity is important for PGE and customers because it reduces the risk of having to pay high coal removal costs, which will ultimately be a part of plant decommissioning, recoverable through Schedule 145 (Boardman Decommissioning Adjustment).

Q. How will PGE operate Boardman in Q4 2020 if there is coal that remains unburned?

A. As described in PGE Exhibit 100, at pages 23-24, in Q4 2020, PGE's decision to economically dispatch the plant will take into account the avoided cost of disposing of the remaining coal. Therefore, if necessary, PGE will run the plant at higher dispatch costs in order to avoid having to incur even greater costs for removing the remaining coal. Moreover, PGE plans to defer and return to customers any benefits that could potentially be realized if the plant is economic to run in the last quarter of 2020, taking into account coal disposal costs.

E. Qualifying Facilities

Q. Please describe PGE's proposal to model Qualifying Facilities.

A. PGE proposed to continue using the mechanism that would track and true-up the actual commercial online dates of newly forecasted Qualifying Facilities (QFs) with the commercial online date used in MONET's NVPC forecast that was approved by the Commission in UE 335. Per the approved mechanism, on a going-forward basis, PGE is tracking the actual online dates of all newly forecasted QFs with the purpose of either refunding to, or collecting from customers, the difference between forecasted and actual online dates. This collection (or refund) would then be deferred and included with the next scheduled AUT filing. The QF tracking mechanism that PGE proposed is described in detail in PGE Exhibit 100 (Section III, part D, at pages 27-28).

Q. Did Parties have recommendations regarding PGE's proposed methodology?

A. Yes, parties have the following recommendations:

<u>OPUC Staff:</u>

1) PGE should apply a percentage derate on forecast QF generation derived from historical new QFs costs compared to new QFs forecast costs.
2) Augment the true up mechanism to include projected MWh generation vs actual MWh generation.

<u>AWEC:</u>

1) AWEC recommends that PGE model QF generation using a contract delay rate (CDR) method similar to the method employed by PacifiCorp.
2) Alternatively, AWEC recommends adding two more steps to the end of PGE's track and true up mechanism:
    a. Calculate the NVPC rate difference resulting from actual CODs.
    b. Multiply the NVPC rate difference by actual billing determinants for 2020.

Q. Please describe Staff's recommendations.

A. Staff analyzed new QFs projected costs compared to actual QF costs in each year from 2015 until 2018 and determined that, on average, new QFs actual costs averaged approximately 46% of PGE's forecast. Based on this analysis Staff is recommending that PGE should derate the forecast new QF generation in MONET by the percentage amount determined from comparing new QF forecast costs with actual new QFs costs in the last four years prior to applying the track and true-up method.[28]

Q. How does Staff propose to improve the accuracy of the QF track and true-up mechanism?

A. Staff is proposing a more extensive true-up which, in addition to re-running MONET with actual QF CODs, would also update the QF generation based on actuals versus forecasts.

Q. How will the additional QF generation proposed by Staff be incorporated in MONET?

A. When performing the MONET re-run to update QF CODs, PGE would also account for the difference between actual MWh production from new QFs compared to PGE's projected MWh production through market power purchases.

Q. What is PGE's position regarding Staff's recommendations.

A. PGE finds Staff's recommendations reasonable. PGE supports: (1) applying a derate on the new QFs expected generation based on the most recent four-year historical average percentage of actuals versus projected QF costs; and (2) a true-up to actual QF production versus projected QF production for all new QF projects; (3) as long as PGE is allowed to continue to implement the true-up mechanism to account for actual vs. projected QF CODs and remove cure payments from the track and true-up mechanism.

Q. Why do you propose to remove cure payments from the QF tracking mechanism?

A. Cure payments are make-whole payments that PGE receives from QFs for replacement power that PGE needs to purchase from the market during the one-year default period after QFs failed to achieve COD.

[28] See OPUC Staff Exhibit 400, pages 4-6.

Q. What is PGE's position regarding AWEC's recommendations?

A. PGE does not agree with AWEC's arguments or recommendations.

Q. Please summarize AWEC's proposal regarding the modeling of QF CODs.

A. AWEC provides two approaches to modeling QF costs. First, AWEC proposes that the expected online date of any new QF be adjusted using the CDR methodology the Commission approved in PacifiCorp's 2018 Transition Adjustment Mechanism proceeding.

Q. Please describe the CDR method.

A. This method compares the projected COD to the actual COD for all QF projects. All delayed projects would be averaged to produce a three-year rolling average of delays to produce a CDR which would then be applied to new QF CODs in each year's power cost forecast. The CDR would be weighted by QF size.

Q. What arguments does AWEC present to support their proposal?

A. Their primary argument is that, with 2018 and 2019 QF additions, PGE now has sufficient history on which to implement the CDR. They also argue that COD variance can be dealt within the PCAM and that PGE should bear some risk related to the large number of QFs due to having a 2025 start for the renewable deficiency period.

Q. Would assuming a three-year average of contract delays be a reasonable method for PGE at this time?

A. No. Even with the 2018 and 2019 QF additions, PGE does not believe that we have sufficient historical information on which to base a three-year average. Only 30 QF PPAs were signed by PGE from 1978 (when PURPA was implemented) through year-end 2015. In addition, PGE only had eight PPAs with a proposed COD in 2016 and 19 PPAs for 2017. Even with the additional 21 new QFs in 2018 and 77 QFs in 2019[29] PGE believes it has insufficient history. Moreover, historic information is not the only issue that PGE has with the CDR method.

Q. Are there other reasons the CDR method is not appropriate for PGE?

A. Yes, we believe this approach does not accurately forecast the actual online delivery dates for new QF contracts and puts significantly more risk on PGE of these QFs not coming online.

Q. Who should bear the risk of QFs not achieving their projected COD?

A. Given the obligation under federal and state laws for the load serving utility to purchase the output from QFs, we believe that neither PGE nor its customers should bear the risk of forecasting an online date of delivery. Adopting the CDR method would potentially impose more of the risk of QFs not meeting their expected COD on PGE.

Q. AWEC argues that the PCAM can effectively address actual COD variance. Would PGE recover the costs associated with these QFs, if their COD was delayed by applying the CDR, through the PCAM?

A. No, recovery through the PCAM would be highly unlikely. Because any potential collection from customers through the PCAM would not be triggered until, at a minimum, actual NVPC exceed the baseline forecast by more than $30 million, it is unlikely PGE would recover any differences in power costs and thus would bear the full risk of using the CDR methodology.

Q. Do you agree with AWEC's argument that it is "fair to shift some of the risk of COD variance to PGE" because PGE has "some control over the number of QFs that seek to sell power to PGE" because PGE has determined to be renewable deficient starting 2025?

[29] See PGE's response to CUB Data Request No. 004, Attachment 004-A provided as Exhibit 306.

A. No. AWEC appears to conclude that in the 2016 IRP PGE determined the start of renewable resource deficiency period to be 2025 and used this to help PGE justify its decision to procure new renewable resources ahead of need. In support of their recommendation AWEC references PGE's revised application to update Schedule 201 QF information filed September 14, 2017, which reflects the renewable deficiency period starting in 2025. However, AWEC fails to explain the full history of how this renewable deficiency period start was determined.

Q. Please provide some background for how the renewable deficiency period was determined to start in 2025.

A. On August 18, 2017,[30] PGE filed revisions to Schedule 201 that included a request for a <u>nonrenewable</u> deficiency period beginning in 2025 and a <u>renewable</u> deficiency period beginning in 2029. We noted the Commission's partial acknowledgement of PGE's 2016 IRP on August 8, 2017 as the basis for the update, with most of the avoided cost inputs coming from the 2016 IRP. The Staff report issued September 7, 2017[31] stated that the Commission acknowledged a nonrenewable capacity need in 2021 (compared to PGE's 2025 request) but did not acknowledge a renewable deficiency period. Staff also states that "PGE calculates its renewable avoided costs using a renewable deficiency period beginning in 2029" and that Staff supports this demarcation. At the September 12, 2017 public meeting, the Commissioners discussed the renewable deficiency demarcation and indicated that 2029 did not seem like a realistic date. They clarified that the Commission established 2029 as the point in which an RPS compliance shortfall (via RECs) may exist, but the renewable avoided cost deficiency date should be based on when an acknowledged IRP takes action to address a

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[30] PGE Exhibit 307 provides PGE's filed revisions to Schedule 201. PGE's filing is also at: https://edocs.puc.state.or.us/efdocs/HAD/um1728had12130.pdf.
[31] PGE Exhibit 308 provides OPUC Staff's report. The report is also at: https://edocs.puc.state.or.us/efdocs/HAU/um1728hau9412.pdf.

compliance need, which 2029 does not represent. An RPS action to meet need was not acknowledged for 2029 in the 2016 IRP. They also noted that procurement of renewables is likely to occur prior to 2029 and thought that should be a consideration when deciding whether 2029 is appropriate. Thus, the Commission issued Order No. 17-247 on September 12, 2017 adopting a 2021 nonrenewable deficiency period and a 2025 renewable deficiency period for avoided cost prices.

Q. So, PGE did not choose the 2025 renewable deficiency date as AWEC assumes?

A. No, the Commission adopted its own recommendation of a 2025 date.

Q. Does PGE agree with AWEC's proposal to calculate the deferred amount by multiplying the retail rate difference with the test year billing determinants?

A. No. PGE must take the delivered net output at contracted fixed prices from QFs, regardless of retail customer loads. The contract price and delivered net output, not billing determinants, determine the cost.

Q. Why is the QF tracking mechanism a more appropriate method to address the issue of QFs not achieving their projected COD?

A. PGE's proposed QF tracking mechanism provides the simplest, most straightforward, and most accurate method for ensuring that accurate online delivery dates are properly reflected in customer prices. In contrast, the CDR method will not be as simple, straightforward or accurate, and is likely to have implementation issues. The QF tracking mechanism ensures that neither PGE nor its customers will bear the risk of QF PPAs not meeting their stated COD. PGE proposes to track and true-up the actual commercial online dates of newly forecast QFs with the purpose of either refunding to, or collecting from customers, the difference between forecasted and actual online dates.

Q. Please summarize PGE's position regarding this issue.

A. PGE finds Staff's recommendations reasonable with the modification of removing cure payments from the mechanism. As such, we propose to continue using the track and true-up mechanism but augment it to also account for actual QF production, apply a reduction to projected QF costs based on historical actual costs vs projected costs, and remove cure payments. We believe this results in a fair method to address the issue of QFs not achieving their projected COD for both PGE and for customers. Under this approach, neither PGE nor its customers would bear the risk of QFs not achieving their projected COD or if QFs are not producing as forecast.

F. Other Items

OPUC Staff

1. Wholesale Transactions

Q. Please summarize Staff's concerns regarding wholesale transactions.

A. Staff is concerned that energy markets volatility could potentially impact the forward price curves used for the final November 15 MONET update and increase PGE's power cost forecast

Q. What is Staff's recommendation?

A. Staff recommends that PGE analyze the potential impact of energy markets volatility on the formation of forward price curves and provide details of this analysis and any changes deemed appropriate prior to the end of the 2020 AUT process.

Q. Does PGE agree with Staff's recommendation?

A. No. PGE already has a robust process to develop and validate forward price curves. Furthermore, PGE believes that an AUT regulatory proceeding is not the appropriate setting to pursue modeling changes in MONET that are not allowed in Schedule 125.

Q. Please describe PGE's process for developing the market forward curve.

A. PGE's Power Operations generally begins developing a market forward curve approximately two years out from a prompt year (i.e., the date for delivery of a commodity). At this point in time, energy trading in the Northwest energy market is relatively illiquid beyond calendar year quotes. In order to arrive at a monthly indicative price, PGE utilizes Intercontinental Exchange[32] (ICE) trading platform data along with actual broker (i.e., market) quotes. Additionally, to further support monthly indicative prices, PGE utilizes spreads between Mid-Columbia and California energy trading hubs[33] as the California market exhibits better liquidity this far into the future.[34] These calendar "strips" are then shaped to introduce the seasonality expressed by the market historically. At approximately one year out from a prompt year, the spread for quarterly strips of energy become liquid and PGE utilizes this information, coupled with historical weights for each month of the prompt year, to develop a monthly forward price. At approximately six months out from the prompt year, the Northwest market will begin trading monthly power and gas contracts. At this point, using the monthly broker quotes, coupled with current quarterly and yearly information from ICE and other sources, PGE's Power Operations can directly produce monthly pricing. This process continues through to PGE's final forward curve update on November 15th, when a five-day

[32] ICE offers a suite of over 1000 energy futures and options contracts. Refer to: https://www.theice.com/energy for additional information.

[33] A spread is the price difference between trading hubs.

[34] For example, if there is a buyer of California hub energy for $45.00, and a seller of the spread between the California hub and Northwest hub for $12.00 on the same day, then the value of the energy at the Northwest hub for that day is $33.00.

average of recent monthly forward prices are averaged in order to further smooth out any day-to-day volatility in the market. By the November curve date, monthly prices are readily observed in the forward curve for that prompt year.

Q. How does PGE validate the market forward curves?

A. While the Power Operations is responsible for recording the market view of the forward curve, PGE's Risk Management department is responsible for validating market forward curves. On a monthly and quarterly basis and for each forward curve used in PGE's NVPC forecasts filed with the Commission, Risk Management compares the forward market curves observed by Power Operations to third party sources (including broker quotes and price indices) to ensure the prices observed and documented by Power Operations accurately reflect the current market prices. PGE has a policy that the curves observed by Power Operations must be within 5% of third-party quotes. In the event any price variances exceed the 5% threshold, Risk Management will adjust the observed curve to bring it to within 5% of the third-party sources. In order to provide Risk Management with the necessary independence to objectively evaluate the activities of Power Operations, there is a functional separation in reporting structure, with Risk Management reporting directly to the Chief Financial Officer (CFO) and the Risk Management Committee (RMC), not Power Operations.

Q. How does volatility in the energy markets impact the forward price curves?

A. Spot market volatility does not directly impact the formation of forward price curves. It is possible, however, that participants in the forward markets may hypothesize that the fundamental supply and demand conditions that give rise to the volatility in the current year will arise again in future years. Therefore, when conditions in the current year materialize, market participants may plan for future years assuming the same results (i.e., expressing a recency bias).

Q. Has market volatility impacted PGE's actual power costs?

A. Yes. Market volatility in general creates more risk for PGE and impacts our actual power costs.

Q. Does PGE plan to make changes to 2020 NVPC modeling in light of recent market volatility in Pacific NW energy markets?

A. No. PGE is precluded from making modeling changes in an AUT beyond the power cost updates allowed in Schedule 125. However, as noted in Staff Exhibit 300, at pages 17-18, PGE is reviewing whether recent events in the Pacific NW energy markets signal a long-term shift in market. To date, PGE has not determined what, if any, specific modeling changes are needed.

Q. Is the 2020 AUT the appropriate proceeding to analyze and determine changes that could be needed to address market volatility?

A. No. PGE does not believe it is reasonable to be required to perform an analysis that will not be introduced into the 2020 AUT, and likely could not be proposed in a future AUT, unless allowed under Schedule 125. Furthermore, such analysis could prove to be outdated by the time PGE does file a GRC, when any potential changes could be implemented.

2. <u>Standards Inputs</u>

Q. Please summarize Staff's issue regarding PGE's modeling of the thermal plants forced outage rates.

A. Staff is concerned with PGE's approach to round to one decimal points the average of historical forced outage rates when determining the test year forced outage rates. Staff states that taking the significant three decimal points and rounding to one, results in increased forced outage rates in nearly every instance for 2020.[35]

Q. What is Staff's recommendation to fix this issue?

A. Staff is recommending PGE round forecasted forced outage rates out to two decimal places instead of one.[36]

Q. Does PGE agree with Staff's recommendation?

A. No. PGE does not believe that Staff's adjustment would provide any significant improvement to PGE modeling forced outage rates and the cost impact would be *de minimis*. Also, depending on the year, applying rounding formulas to one decimal can go in either direction – up or down.

3. <u>Wheatridge</u>

Q. Please summarize Staff's concern with and recommendation for PGE's treatment of the Wheatridge Renewable Energy Facility (Wheatridge).

A. Staff recommends that Wheatridge variable costs and benefits be forecast and reflected in PGE's 2020 AUT and that the failure to do so is "one-sided and inconsistent with Commission policy and precedent regarding the ratemaking treatment for variable costs and benefits for RPS-compliant resources, including PTCs."[37] In support of their argument, Staff points to a number of orders from prior proceedings, which, they argue, support a requirement that all variable power costs from RPS-compliant resources be included within the AUT and that a failure to do so is, in some way, requesting "dollar-for-dollar recovery" and inconsistent with prior precedent.[38]

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[35] See OPUC Staff Exhibit 400, page 7, lines 15-22.
[36] See OPUC Staff Exhibit 400, page 8, lines 2-4.
[37] OPUC Staff Exhibit 100, page 12, lines 19-21.
[38] OPUC Staff Exhibit 100, pages 14 and 15.

Q. What is the primary reason that PGE has not included any Wheatridge costs or benefits within the 2020 AUT forecast?

A. PGE has not included any costs or benefits related to Wheatridge primarily due to Wheatridge's current forecasted in-service date. Based on PGE's contract guarantees regarding both the owned- and PPA-based portions of Wheatridge, the wind resources are currently expected to be placed in-service at the very end of 2020. In fact, the current estimated commercial online date is December 31, 2020. As such, including all costs and benefits within a RAC filing through Schedule 122 ensures that, should Wheatridge come into service prior to December 31, 2020, customers will receive the most current forecast of benefits, while incurring the most current expectation of costs commensurate with the actual online date of the project.

Q. Is PGE allowed to include NVPC-related costs within a Schedule 122 filing?

A. Yes. Schedule 122 allows for the recovery of "qualifying Company-owned or contracted new renewable energy resource and energy storage projects associated with renewable energy resources (including associated transmission) not otherwise included in rates."[39] As no costs or benefits from Wheatridge are currently included in rates, they are allowed to be included within Schedule 122.

Q. Does any prior legislation or Commission order preclude PGE from including NVPC-related costs within a Schedule 122 filing?

A. No. Staff points to language in Order No. 07-572 that specifies the RAC can include forecasted costs and cost offsets authorized by Senate Bill (SB) 838 and not captured in a utility's annual power cost update. It is easy to see that this language is included to ensure

[39] PGE Schedule 122-1, Fourteenth Revision.

there is no double counting of costs and benefits between a RAC and annual power cost proceeding. However, PGE has not included or "captured" any costs or benefits from Wheatridge in its 2020 AUT, because none are currently forecast. Thus, the RAC is the appropriate vehicle for inclusion.

Q. Staff also seems to be arguing that by including NVPC-related costs and benefits within a RAC, PGE would be requesting "dollar-for-dollar" recovery, which the Commission ruled was not a requirement prescribed in ORS 469A.120(1). How do you respond?

A. No matter where PGE includes a forecast of NVPC-related costs and benefits, whether through Schedule 125, Schedule 122, or through a GRC, they are still inherently a forecasted amount. None of these proceedings allow for PGE to "true-up" its forecasted variable costs to actuals and PGE is not planning on requesting such treatment.

Q. Is Staff correct in its conclusion that SB 1547 only allows for PTCs to be included in annual NVPC proceedings?

A. No. SB 1547, Section 18b., codified as Oregon Revised Statute (ORS) 757.264, allows for PTCs to be included in PGE's AUT. Further, it does not preclude PGE from including a PTC forecast within a RAC filing if it is not captured within the applicable AUT proceeding.

Q. Have prior PGE RAC filings included variable power costs?

A. Yes. All of PGE's prior RAC filings including Docket Nos. UE 220, UE 249, UE 288, and UE 297 have included some portion of net variable power costs within the filed and approved revenue requirement.

Q. Please summarize PGE's response to Staff's issues regarding Wheatridge.

A. PGE has not included any costs or benefits from Wheatridge within the 2020 AUT because the current forecast has Wheatridge coming into service on December 31, 2020. PGE does not currently have a better forecasted in-service date from which to include any forecasted costs or benefits from Wheatridge for 2020. Furthermore, there is no prior Commission Order or Oregon Legislative mandate that prohibits including NVPC-related costs and benefits within a RAC filing, provided they are not double counted elsewhere. In fact, PGE has included some portion of NVPC-related costs and benefits within all of its previously authorized RAC filings.

AWEC

4. GTN Pipeline 2020 Rate Reduction

Q. Please summarize AWEC's adjustment related to the GTN Pipeline rate reduction.

A. AWEC argues that, according to the settlement between shippers and the GTN Pipeline filed with the Federal Energy Regulatory Commission on October 16, 2018, the GTN rates were set to decline by approximately 10% on January 1, 2019 and an additional 7.6% on January 1, 2020. As such PGE should reduce the GTN rate in its 2020 power cost forecast to reflect the change stipulated in the settlement agreement.

Q. What is the power cost adjustment related to updating the 2020 GTN pipeline rate that AWEC is proposing?

A. AWEC is proposing an approximate $0.5 million reduction.

Q. Does PGE agree with AWEC's adjustment?

A. Yes. PGE inadvertently missed updating the GTN pipeline rate in our initial 2020 power cost forecast. PGE has now reflected the updated GTN rate and associated power cost reduction within the recently filed July 15 NVPC update.

CUB

5. Inflation Rate in MONET

Q. Please summarize CUB's adjustment related to the inflation rate used in MONET.

A. CUB argues that PGE should use a 2% inflation rate instead of the 2.5% used in MONET.

Q. How does CUB justify this proposed adjustment?

A. CUB argues that PGE is already using a 2% general inflation rate in our 2016 Integrated Resource Plan (IRP) filing. Therefore, PGE should be synchronized between our annual power cost and IRP filings by using the same inflation rate. Moreover, CUB argues that a 2% inflation rate is also aligned with the Federal Reserve inflation targeting policy that sets a symmetrical inflation target at a 2% level.

Q. Do you agree with CUB's adjustment?

A. PGE does not agree with CUB's reasoning that we should be aligned between IRP and AUT filings. The IRP results in a mid-term to long-term action plan for PGE's resource portfolio whereas the AUT is a short-term, one year out power cost forecast. Furthermore, if PGE was to reduce the power cost inflation rate used in MONET from 2.5% to 2% we should also update the inflation rate applied in EIM calculations, which would decrease PGE's EIM benefit forecast.

Q. If PGE were to adjust its rate down to 2%, would it result in the amount that CUB has calculated?

A. Not exactly. While CUB's $70,000 adjustment to PGE's 2020 power cost forecast was calculated correctly, contract updates revise this amount moving forward. Specifically, the Vansycle contract was escalated by two years from a 2018 price in PGE's April 1 initial filing. However, PGE has now received the contracted escalation rate for 2019 and has included this in our July 15 Power Cost update. Doing so, reduces CUB's adjustment to approximately $46,000.

III. Summary and Conclusion

Q. In closing, please summarize your proposals regarding the issues identified by parties.

A. With the exceptions discussed above, we recommend the Commission reject the parties' positions regarding the issues identified. The parties largely propose adjustment that are based on incomplete and faulty analysis and inaccurate or misguided assumptions. Furthermore, several parties' proposals, including proposals for wind capacity factors, gas optimization, Boardman dispatch logic, and wholesale transactions require modeling changes not allowed in Schedule 125. Parties' recommended reductions would unfairly introduce a significant downward bias on PGE's NVPC forecast, making it highly unlikely PGE would recover its prudently incurred NVPC for 2020.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	PGE Tariff Schedule 125
302C	Wind Lost Energy-Related Costs
303	Wind Production Tax Credits Actuals vs. Forecast
304C	PGE's Gas Pipeline and Storage Rights, and Gas-Fired Plants
305C	California-Oregon Border Volumes
306	PGE's Response to CUB Data Request No. 004
307	PGE's Revisions to Schedule 201 in Docket No. UM 1728
308	OPUC Staff's Report in Docket UM 1728

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 90, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91, and 95 are exempt from Schedule 125.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Wind energy forecast based on a five-year rolling average.
- Costs associated with wind integration.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs.
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- Reciprocating engine lubrication oil costs.
- Projections of State and Federal Production Tax Credits. **(N)**
- No other changes or updates will be made in the annual filings under this schedule.

SCHEDULE 125 (Continued)

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0320. **(R)**

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES

Schedule		¢ per kWh	
7		0.000	
15		0.000	
32		0.000	
38		0.000	**(C)**
47		0.000	
49		0.000	
75			
	Secondary	0.000 [(1)]	
	Primary	0.000 [(1)]	
	Subtransmission	0.000 [(1)]	
83		0.000	
85			
	Secondary	0.000	
	Primary	0.000	
89			
	Secondary	0.000	
	Primary	0.000	
	Subtransmission	0.000	
90		0.000	
91		0.000	
92		0.000	
95		0.000	

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

Exhibit 302C

Protected Information Subject to Protective Order 19-112

Portland General Electric Company
Production Tax Credit History
2007-2018

		Credits Generated		
		GRC/AUT	**Actual**	**Difference**
2007		-	555,220	(555,220)
2008	UE 188	7,730,264	8,071,770	(341,506)
2009	UE 197 (GRC), 209 (RAC)	11,824,934	10,475,766	1,349,168
2010	UE 197 (GRC), 209 (RAC), 22(	21,150,921	18,334,514	2,816,407
2011	UE 215	31,136,798	25,913,316	5,223,482
2012	UE 215	31,136,798	24,387,352	6,749,446
2013	UE 215	31,136,798	27,388,791	3,748,007
2014	UE 262, 288 (RAC)	25,873,682	27,004,093	(1,130,411)
2015	UE 283	48,567,221	41,288,763	7,278,458
2016	UE 294	49,150,287	44,264,732	4,885,555
2017	UE 308	45,349,676	38,213,164	7,136,512
2018	UE 319	39,215,049	38,022,026	1,193,023
				38,352,920.04

Exhibit 304C

Protected Information Subject to Protective Order 19-112

Exhibit 305C

Protected Information Subject to Protective Order 19-112

May 23, 2019

TO: Bob Jenks
Oregon Citizens' Utility Board

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to CUB Data Request No. 004
Dated May 10, 2019

Request:

Please provide a list of all QFs forecasted in an AUT to come online in the 2017, 2018, and 2019 calendar years, showing the COD when the QF was forecasted in the AUT and the COD when it actually came on line. If a QF has yet to come online, please provide its expected COD.

Response:

Attachment 004-A provides all QFs that were forecasted to come online in PGE's 2017 (UE 308), 2018 (UE 319), and 2019 (UE 335) AUT filings, including their contractually stated Commercial Operation Dates (CODs) at the time of the AUT filing and the actual CODs for the QFs that achieved commercial operation. The actual COD dates for QFs that failed to meet their contractually stated CODs or are scheduled to achieve CODs between the current date and the end of 2019 are tagged as 'N/A'. QF contracts that have been amended with a new COD are listed in the "QF Contract Amendments" tab included in Attachment 004-A.

Please note that, prior to UE 335, PGE was modeling QFs in NVPC filings based on their Initial Delivery Date (IDD) rather than their COD. The IDD occurs prior to the COD with the time period in-between used for project testing.

During the period between IDD and COD, all energy deliveries from QFs are paid at the off-peak avoided cost rate. Additionally, IDD is not a mandated contractual milestone whereas COD is. Hence, PGE changed QF modeling from IDD to COD in its 2019 NVPC modeling in UE 335 to more accurately capture the costs associated with QF energy purchases and alignment with contractual milestones.

UE 359

Attachment 004-A

Provided in Electronic Format Only

QFs in PGE's NVPC Filings
2017-2019

	QF contracts forecasted to come online in 2017 per 2017 AUT final filing	IDD per contract	IDD per filing (2017 final filing - step 83)	Actual IDD	Actual COD
1	**OE Solar 2 QF**	11/30/2017	12/1/2017	N/A	N/A
2	**Butler Solar QF**	11/1/2017	11/1/2017	N/A	N/A
3	**Silverton Solar QF**	11/30/2016	1/1/2017	12/4/2017	2/8/2018
4	**Glenn Creek Solar QF**	9/30/2017	10/1/2017	N/A	N/A
5	**Boring Solar QF**	9/30/2017	10/1/2017	2/25/2019	4/3/2019
6	**Sheep Solar QF**	5/1/2017	5/1/2017	12/15/2017	2/8/2018
7	**Drift Creek Solar QF**	6/30/2017	7/1/2017	N/A	N/A
8	**Amity Solar**	11/1/2017	11/1/2017	N/A	N/A
9	**Bridgeport Solar**	11/1/2017	11/1/2017	N/A	N/A
10	**Duus Solar**	11/1/2017	11/1/2017	N/A	N/A
11	**Firwood Solar**	11/1/2017	11/1/2017	N/A	N/A
12	**Fishback Solar**	11/1/2017	11/1/2017	N/A	N/A
13	**Starlight Solar**	11/1/2017	11/1/2017	N/A	N/A
14	**Stringtown Solar**	11/1/2017	11/1/2017	N/A	N/A
15	**Willamina Solar QF**	12/31/2016	1/1/2017	N/A	N/A
16	**O'Neil Creek Solar QF**	9/30/2017	10/1/2017	N/A	N/A
17	**St Louis Solar QF**	9/30/2017	10/1/2017	N/A	N/A
18	**Palmer Creek Solar QF**	9/30/2017	10/1/2017	N/A	N/A
19	**Rafael Solar QF**	9/30/2017	10/1/2017	N/A	N/A
20	**Case Creek Solar QF**	9/30/2017	10/1/2017	N/A	N/A
21	**Ballston Solar QF**	9/30/2017	10/1/2017	12/3/2018	12/18/2018

	QF contracts forecasted to come online in 2018 per 2018 GRC final filing	IDD per contract	IDD per filing (2018 GRC final filing - step 152)	Actual IDD	Actual COD
1	Fremont Solar QF	4/1/2018	4/1/2018	N/A	N/A
2	Lakeview Airport Solar 10 QF	3/31/2018	3/31/2018	N/A	N/A
3	Starvation Solar QF	12/25/2018	12/1/2018	N/A	N/A
4	Tygh Valley Solar QF	12/25/2018	12/1/2018	N/A	N/A
5	Wasco Solar I QF	12/25/2018	12/1/2018	N/A	N/A
6	Dayton Solar I QF	12/25/2018	12/1/2018	N/A	N/A
7	OE Solar 1 QF	9/5/2018	9/1/2018	N/A	N/A
8	OE Solar 3 QF	10/1/2018	10/1/2018	8/7/2018	9/7/2018
9	OE Solar 4 QF	5/30/2018	6/1/2018	N/A	N/A
10	Morrow Solar QF	9/1/2018	9/1/2018	N/A	N/A
11	Willamina Mill Solar QF	7/31/2018	7/31/2018	N/A	N/A
12	Day Hill Solar QF	7/31/2018	7/31/2018	N/A	N/A
13	Labish Solar QF	2/28/2018	2/28/2018	12/3/2018	12/18/2018
14	Kale Patch Solar QF	5/31/2018	5/31/2018	N/A	N/A
15	Thomas Creek Solar QF	3/31/2018	3/31/2018	N/A	N/A
16	Yamhill Creek Solar QF	3/31/2018	3/31/2018	N/A	N/A
17	Brush Creek Solar QF	3/31/2018	3/31/2018	N/A	N/A
18	Tickle Creek Solar QF	2/28/2018	2/28/2018	N/A	N/A
19	Volcano Solar QF	11/30/2017	1/1/2018	N/A	N/A
20	SORT Recycling QF	7/1/2018	7/1/2018	N/A	N/A
21	Evergreen Biopower QF	1/1/2018	1/1/2018	1/17/2018	2/1/2018

	QF contracts forecasted to come online in 2019 per 2019 GRC final filing	COD per contract	COD per filing (2019 GRC final filing - step 163)	Actual COD
1	Starvation Solar QF	1/25/2019	1/25/2019	N/A
2	Tygh Valley Solar QF	1/25/2019	1/25/2019	N/A
3	Wasco Solar I QF	1/25/2019	1/25/2019	N/A
4	Dayton Solar I QF	1/25/2019	1/25/2019	N/A
5	Butler Solar QF	12/31/2019	12/31/2019	N/A
6	Drift Creek Solar QF	4/1/2019	4/1/2019	N/A
7	Boring Solar QF	1/31/2019	1/31/2019	4/3/2019
8	Amity Solar QF	12/31/2019	12/31/2019	N/A
9	Bridgeport Solar QF	12/31/2019	12/31/2019	N/A
10	Duus Solar QF	12/31/2019	12/31/2019	N/A
11	Firwood Solar QF	12/31/2019	12/31/2019	N/A
12	Starlight Solar QF	12/31/2019	12/31/2019	N/A
13	Stringtown Solar QF	12/31/2019	12/31/2019	N/A
14	Fort Rock Solar I QF	4/27/2019	4/27/2019	N/A
15	Fort Rock Solar II QF	4/27/2019	4/27/2019	N/A
16	O'Neil Creek Solar QF	3/24/2019	3/24/2019	N/A
17	St Louis Solar QF	2/10/2019	2/10/2019	N/A
18	Palmer Creek Solar QF	7/1/2019	7/1/2019	N/A
19	Willamina Mill Solar QF	8/14/2019	8/14/2019	N/A
20	Rafael Solar QF	6/30/2019	6/30/2019	N/A
21	Case Creek Solar QF	5/5/2019	5/5/2019	N/A
22	Fort Rock Solar IV QF	6/26/2019	6/26/2019	N/A
23	Riley Solar I QF	6/27/2019	6/27/2019	N/A
24	Alfalfa Solar QF	6/26/2019	6/26/2019	N/A
25	South Burns Solar I QF	7/20/2019	7/20/2019	N/A
26	Suntex Solar QF	7/20/2019	7/20/2019	N/A
27	West Hines Solar I QF	7/20/2019	7/20/2019	N/A
28	Alkali Solar QF	7/31/2019	7/31/2019	N/A
29	Rock Garden Solar QF	7/31/2019	7/31/2019	N/A
30	Harney Solar I QF	6/27/2019	6/27/2019	N/A
31	OE Solar 5 QF	6/30/2019	6/30/2019	N/A
32	Day Hill Solar QF	7/14/2019	7/14/2019	N/A
33	Kale Patch Solar QF	7/31/2019	7/31/2019	N/A
34	Thomas Creek Solar QF	2/1/2019	2/1/2019	N/A
35	Brush Creek Solar QF	4/5/2019	4/5/2019	N/A
36	OE Solar 6 QF	6/30/2019	6/30/2019	N/A
37	Solar Star Solar I QF	12/31/2019	12/31/2019	N/A
38	Brightwood Solar QF	12/31/2019	12/31/2019	N/A
39	Airport Solar QF	11/1/2019	11/1/2019	N/A
40	Tickle Creek Solar QF	1/31/2019	1/31/2019	N/A
41	Sulus Solar 22 (AM West Silverton) QF	12/2/2019	12/2/2019	N/A
42	Ashfield Solar QF	12/2/2019	12/2/2019	N/A
43	Black Forest Solar QF	12/2/2019	12/2/2019	N/A
44	Bristol Solar QF	12/2/2019	12/2/2019	N/A
45	Fairview Solar QF	12/2/2019	12/2/2019	N/A
46	Sulus Solar 17 QF	12/2/2019	12/2/2019	N/A
47	Sulus Solar 25 QF	12/2/2019	12/2/2019	N/A
48	Milford Solar QF	12/2/2019	12/2/2019	N/A
49	Sulus Solar 28 QF	12/2/2019	12/2/2019	N/A
50	Sulus Solar 6 QF	12/2/2019	12/2/2019	N/A
51	Sulus Solar 33 QF	12/2/2019	12/2/2019	N/A
52	Sulus Solar 29 QF	12/2/2019	12/2/2019	N/A
53	Sulus Solar 35 QF	12/2/2019	12/2/2019	N/A
54	Sulus Solar 7 QF	12/2/2019	12/2/2019	N/A
55	Greenpark Solar QF	12/2/2019	12/2/2019	N/A
56	Kensington Solar QF	12/2/2019	12/2/2019	N/A
57	Kerry Solar QF	12/2/2019	12/2/2019	N/A
58	Gun Club Solar QF	12/1/2019	12/1/2019	N/A
59	Cosper Creek Solar QF	12/1/2019	12/1/2019	N/A
60	Dunn Rd Solar QF	10/31/2019	10/31/2019	N/A
61	Dryland Solar QF	12/1/2019	12/1/2019	N/A
62	Mountain Meadow Solar QF	12/1/2019	12/1/2019	N/A
63	River Valley Solar QF	12/1/2019	12/1/2019	N/A
64	Sandy River Solar QF	12/1/2019	12/1/2019	N/A
65	Fruitland Creek Solar QF	12/1/2019	12/1/2019	N/A
66	Mt Hope Solar QF	12/1/2019	12/1/2019	N/A
67	Raven Loop Solar QF	12/1/2019	12/1/2019	N/A
68	Brush College Solar QF	12/1/2019	12/1/2019	N/A
69	Williams Acres Solar QF	12/1/2019	12/1/2019	N/A
70	Zena Solar QF	12/1/2019	12/1/2019	N/A
71	Ashcroft Solar QF	9/30/2019	9/30/2019	N/A
72	Townsend Solar QF	9/30/2019	9/30/2019	N/A
73	Kaiser Creek Solar QF	12/1/2019	12/1/2019	N/A
74	Ridgeway Solar QF	12/1/2019	12/1/2019	N/A
75	Parrott Creek Solar QF	12/1/2019	12/1/2019	N/A
76	Energy Partners I QF	6/1/2019	6/1/2019	N/A
77	Energy Partners II QF	6/1/2019	6/1/2019	N/A

Portland General Electric Company
Legal Department
121 SW Salmon Street • Portland, Oregon 97204
503-464-7181 • Facsimile 503-464-2200

V. Denise Saunders
Associate General Counsel

August 18, 2017

Via Electronic Filing

Oregon Public Utility Commission
Attention: Filing Center
PO Box 1088
Salem OR 97308-1088

Re: **UM 1728 – PORTLAND GENERAL ELECTRIC COMPANY's Application to Update Schedule 201 Qualifying Facility Information – Compliance Filing**

Attention Filing Center:

Portland General Electric Company (PGE) submits this filing pursuant to Oregon Administrative Rules 860-029-0040(4)(a) and 860-001-0420 and Order Nos. 10-488, 11-505, and 14-058.

This filing revises Schedule 201, Qualifying Facility Power Purchase Information for Qualifying Facilities 10 MW or Less, Sheet Nos. 201-1 through Sheet Nos. 201-23. This filing also includes a Motion for Temporary Relief from Schedule 201 Prices (Motion) with an accompanying Declaration of Robert Macfarlane.

The enclosed Schedule 201 shows a requested effective date of **September 18, 2017**, which is consistent with OAR 860-029-0040(4)(a) and the primary relief requested in PGE's Motion. If the Commission denies the primary relief requested in the Motion but grants the alternative relief, the enclosed Schedule 201 will have an effective date of **August 8, 2017**.

This filing changes prices only. The major drivers for the price changes to Schedule 201 in this filing are as follows:

- The deficiency periods start in a later year.
- For both Standard and Renewable Avoided Costs, overnight capital costs are lower using the costs from the 2016 IRP.

Attachment A provides a description of standard avoided costs.

Attachment B provides a description of renewable avoided costs.

Attachment C provides a list of sources for various assumptions used to calculate prices.

In addition, on July 20, 2017, PGE filed for changes to Schedule 201 in compliance with Commission Order No. 17-256 in UM 1805. Those changes have not been approved and are not yet effective. PGE will include the changes from that filing in Schedule 201 when the changes become effective.

Also provided as a courtesy are redlined versions of Sheet Nos. 201-1 through Sheet Nos. 201-23.

Should you have any questions or comments regarding this filing, please contact Rob Macfarlane at (503) 464-8954.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com.

Thank you in advance for your assistance.

Sincerely,

V. Denise Saunders

V. Denise Saunders
Associate General Counsel

VDS:bop

Enclosures

cc: Service List UM 1610

UM 1728 Application to Update
Schedule 201 Qualifying Facility Information

(*Effective date September 18, 2017*)

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

SCHEDULE 201 (Continued)

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

SCHEDULE 201 (Continued)

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

SCHEDULE 201 (Continued)

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 18.59%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 15.33%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind and Solar QFs (Tables 2a, 2b, 3a, and 3b) include a reduction for the integration costs in Table 7. However, if the Wind or Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b or 3a and 3b, for a net-zero effect.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

TABLE 1a
Avoided Costs
Standard Fixed Price Option for Base Load QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	57.28	57.40	57.49	56.78	56.75	56.67	56.77	56.85	56.97	57.07	57.81	57.92
2026	59.17	59.29	59.34	58.62	58.63	58.69	58.79	58.89	59.03	59.16	60.03	60.15
2027	61.01	61.13	61.04	60.30	60.44	60.19	60.29	60.39	60.52	61.27	59.92	60.04
2028	61.23	61.31	61.19	60.52	60.66	60.78	60.88	61.00	61.12	61.26	62.44	62.57
2029	64.03	64.16	64.28	63.58	63.76	64.88	65.00	65.13	65.28	65.40	66.74	66.88
2030	69.60	70.59	70.73	70.05	70.25	70.41	70.56	70.72	70.89	71.77	72.44	72.62
2031	74.30	74.48	74.10	73.00	73.15	73.04	73.18	73.34	73.51	73.69	74.85	75.02
2032	76.53	76.62	76.32	75.09	75.30	75.49	75.64	75.81	76.00	76.25	77.82	78.02
2033	80.07	80.28	80.02	78.86	79.09	79.29	79.46	79.64	79.85	80.26	81.68	81.90
2034	83.89	84.11	82.95	81.61	81.86	82.07	82.25	82.45	82.67	82.91	84.66	84.89
2035	86.73	86.97	85.83	84.45	84.70	84.37	84.55	84.75	84.99	85.49	86.97	87.42
2036	89.63	89.87	88.67	87.20	87.49	87.12	87.32	87.54	87.78	88.31	89.86	90.33
2037	92.90	93.16	91.91	90.37	90.65	90.28	90.48	90.71	90.95	91.53	93.15	93.66
2038	96.17	96.45	95.12	93.50	93.81	93.42	93.63	93.87	94.14	94.74	96.45	96.97
2039	99.60	99.87	98.49	96.79	97.11	96.69	96.92	97.17	97.45	98.09	99.87	100.43
2040	103.14	103.43	101.98	100.19	100.53	100.09	100.34	100.59	100.89	101.55	103.43	104.02
2041	106.88	107.19	105.65	103.77	104.11	103.66	103.92	104.18	104.50	105.20	107.17	107.79
2042	110.75	111.07	109.46	107.49	107.86	107.38	107.63	107.92	108.25	108.98	111.07	111.71

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 1b
Avoided Costs
Standard Fixed Price Option for Base Load QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	27.96	28.08	28.17	27.46	27.43	27.35	27.45	27.53	27.65	27.75	28.49	28.60
2026	29.26	29.39	29.43	28.71	28.72	28.79	28.89	28.99	29.12	29.25	30.12	30.24
2027	30.50	30.63	30.54	29.80	29.94	29.69	29.79	29.89	30.01	30.76	29.41	29.54
2028	30.11	30.19	30.08	29.41	29.55	29.66	29.77	29.88	30.01	30.15	31.33	31.45
2029	32.29	32.42	32.54	31.85	32.02	33.14	33.26	33.39	33.54	33.66	35.01	35.15
2030	37.23	38.22	38.36	37.68	37.88	38.04	38.19	38.35	38.52	39.40	40.07	40.25
2031	41.28	41.46	41.08	39.98	40.13	40.02	40.16	40.32	40.49	40.67	41.83	42.00
2032	43.06	43.15	42.85	41.62	41.84	42.02	42.17	42.35	42.54	42.79	44.35	44.55
2033	45.72	45.92	45.67	44.51	44.74	44.94	45.11	45.28	45.50	45.91	47.33	47.54
2034	48.74	48.96	47.80	46.46	46.71	46.91	47.10	47.29	47.51	47.76	49.51	49.74
2035	50.99	51.23	50.09	48.70	48.96	48.62	48.81	49.01	49.25	49.75	51.23	51.68
2036	53.29	53.53	52.33	50.86	51.15	50.78	50.98	51.20	51.45	51.97	53.52	53.99
2037	55.72	55.98	54.72	53.19	53.47	53.09	53.30	53.52	53.77	54.35	55.97	56.48
2038	58.24	58.52	57.19	55.57	55.88	55.49	55.70	55.94	56.21	56.81	58.52	59.04
2039	60.91	61.18	59.80	58.11	58.42	58.01	58.24	58.48	58.77	59.40	61.18	61.74
2040	63.68	63.97	62.52	60.73	61.07	60.63	60.88	61.12	61.43	62.09	63.97	64.55
2041	66.63	66.94	65.40	63.52	63.86	63.41	63.66	63.93	64.25	64.95	66.92	67.54
2042	69.70	70.02	68.40	66.43	66.80	66.33	66.57	66.86	67.20	67.93	70.02	70.66

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 2a
Avoided Costs
Standard Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	41.62	41.74	41.83	41.12	41.09	41.01	41.11	41.20	41.32	41.42	42.16	42.27
2026	43.20	43.32	43.37	42.65	42.66	42.72	42.82	42.92	43.06	43.19	44.06	44.18
2027	44.72	44.84	44.75	44.02	44.15	43.90	44.00	44.11	44.23	44.98	43.63	43.76
2028	44.62	44.70	44.58	43.91	44.05	44.16	44.27	44.38	44.51	44.65	45.83	45.96
2029	47.09	47.22	47.33	46.64	46.82	47.94	48.05	48.18	48.34	48.45	49.80	49.94
2030	52.32	53.31	53.45	52.77	52.97	53.13	53.28	53.44	53.61	54.49	55.16	55.34
2031	56.67	56.86	56.48	55.37	55.52	55.41	55.56	55.72	55.89	56.06	57.23	57.40
2032	58.66	58.75	58.45	57.22	57.43	57.62	57.77	57.95	58.13	58.38	59.95	60.15
2033	61.73	61.93	61.68	60.52	60.75	60.95	61.12	61.30	61.51	61.92	63.34	63.55
2034	65.13	65.35	64.19	62.85	63.10	63.31	63.49	63.68	63.91	64.15	65.90	66.13
2035	67.65	67.89	66.75	65.37	65.62	65.29	65.48	65.68	65.91	66.42	67.89	68.34
2036	70.22	70.47	69.26	67.80	68.08	67.72	67.92	68.14	68.38	68.91	70.45	70.93
2037	73.05	73.32	72.06	70.53	70.80	70.43	70.64	70.86	71.11	71.69	73.30	73.81
2038	75.92	76.20	74.87	73.25	73.56	73.17	73.38	73.62	73.89	74.49	76.20	76.72
2039	78.95	79.22	77.84	76.15	76.46	76.04	76.27	76.52	76.81	77.44	79.22	79.78
2040	82.07	82.36	80.91	79.13	79.46	79.02	79.27	79.52	79.83	80.49	82.36	82.95
2041	85.39	85.70	84.16	82.28	82.62	82.17	82.43	82.70	83.01	83.71	85.69	86.30
2042	88.84	89.16	87.55	85.58	85.94	85.47	85.72	86.01	86.34	87.07	89.16	89.80

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 2b
Avoided Costs
Standard Fixed Price Option for Wind QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	26.96	27.08	27.17	26.46	26.43	26.35	26.45	26.53	26.65	26.75	27.49	27.60
2026	28.24	28.37	28.41	27.69	27.70	27.77	27.87	27.97	28.10	28.23	29.10	29.22
2027	29.46	29.59	29.50	28.76	28.90	28.65	28.75	28.85	28.97	29.72	28.37	28.50
2028	29.05	29.13	29.02	28.35	28.49	28.60	28.71	28.82	28.95	29.09	30.27	30.39
2029	31.21	31.34	31.46	30.77	30.94	32.06	32.18	32.31	32.46	32.58	33.93	34.07
2030	36.13	37.12	37.26	36.58	36.78	36.94	37.09	37.25	37.42	38.30	38.97	39.15
2031	40.16	40.34	39.96	38.86	39.01	38.90	39.04	39.20	39.37	39.55	40.71	40.88
2032	41.92	42.01	41.71	40.48	40.70	40.88	41.03	41.21	41.40	41.65	43.21	43.41
2033	44.55	44.75	44.50	43.34	43.57	43.77	43.94	44.11	44.33	44.74	46.16	46.37
2034	47.55	47.77	46.61	45.27	45.52	45.72	45.91	46.10	46.32	46.57	48.32	48.55
2035	49.78	50.02	48.88	47.49	47.75	47.41	47.60	47.80	48.04	48.54	50.02	50.47
2036	52.05	52.29	51.09	49.62	49.91	49.54	49.74	49.96	50.21	50.73	52.28	52.75
2037	54.46	54.72	53.46	51.93	52.21	51.83	52.04	52.26	52.51	53.09	54.71	55.22
2038	56.95	57.23	55.90	54.28	54.59	54.20	54.41	54.65	54.92	55.52	57.23	57.75
2039	59.60	59.87	58.49	56.80	57.11	56.70	56.93	57.17	57.46	58.09	59.87	60.43
2040	62.34	62.63	61.18	59.39	59.73	59.29	59.54	59.78	60.09	60.75	62.63	63.21
2041	65.26	65.57	64.03	62.15	62.49	62.04	62.29	62.56	62.88	63.58	65.55	66.17
2042	68.31	68.63	67.01	65.04	65.41	64.94	65.18	65.47	65.81	66.54	68.63	69.27

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3a
Avoided Costs
Standard Fixed Price Option for Solar QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	38.93	39.05	39.13	38.43	38.39	38.32	38.42	38.50	38.62	38.72	39.46	39.57
2026	40.45	40.57	40.62	39.90	39.91	39.97	40.07	40.17	40.31	40.44	41.31	41.43
2027	41.91	42.04	41.95	41.21	41.35	41.10	41.20	41.30	41.43	42.17	40.83	40.95
2028	41.75	41.84	41.72	41.05	41.19	41.30	41.41	41.52	41.65	41.79	42.97	43.10
2029	44.17	44.30	44.42	43.72	43.90	45.02	45.14	45.27	45.42	45.54	46.88	47.02
2030	49.34	50.33	50.48	49.79	49.99	50.15	50.31	50.46	50.63	51.51	52.18	52.36
2031	53.64	53.82	53.44	52.34	52.49	52.37	52.52	52.68	52.85	53.02	54.19	54.36
2032	55.58	55.67	55.37	54.14	54.36	54.54	54.69	54.87	55.06	55.31	56.87	57.07
2033	58.57	58.78	58.52	57.36	57.59	57.79	57.96	58.14	58.35	58.76	60.18	60.40
2034	61.90	62.12	60.96	59.62	59.87	60.07	60.26	60.45	60.67	60.92	62.66	62.90
2035	64.37	64.61	63.46	62.08	62.34	62.00	62.19	62.39	62.63	63.13	64.61	65.06
2036	66.88	67.12	65.92	64.46	64.74	64.38	64.58	64.80	65.04	65.57	67.11	67.58
2037	69.64	69.90	68.64	67.11	67.38	67.01	67.22	67.44	67.69	68.27	69.88	70.40
2038	72.43	72.71	71.39	69.77	70.08	69.68	69.89	70.13	70.40	71.01	72.71	73.23
2039	75.39	75.66	74.28	72.59	72.90	72.49	72.72	72.96	73.25	73.88	75.66	76.22
2040	78.44	78.74	77.28	75.50	75.83	75.39	75.64	75.89	76.20	76.86	78.74	79.32
2041	81.69	82.00	80.46	78.58	78.92	78.47	78.72	78.99	79.31	80.01	81.98	82.60
2042	85.07	85.39	83.77	81.80	82.17	81.70	81.94	82.23	82.57	83.30	85.39	86.03

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3b
Avoided Costs
Standard Fixed Price Option for Solar QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	26.96	27.08	27.17	26.46	26.43	26.35	26.45	26.53	26.65	26.75	27.49	27.60
2026	28.24	28.37	28.41	27.69	27.70	27.77	27.87	27.97	28.10	28.23	29.10	29.22
2027	29.46	29.59	29.50	28.76	28.90	28.65	28.75	28.85	28.97	29.72	28.37	28.50
2028	29.05	29.13	29.02	28.35	28.49	28.60	28.71	28.82	28.95	29.09	30.27	30.39
2029	31.21	31.34	31.46	30.77	30.94	32.06	32.18	32.31	32.46	32.58	33.93	34.07
2030	36.13	37.12	37.26	36.58	36.78	36.94	37.09	37.25	37.42	38.30	38.97	39.15
2031	40.16	40.34	39.96	38.86	39.01	38.90	39.04	39.20	39.37	39.55	40.71	40.88
2032	41.92	42.01	41.71	40.48	40.70	40.88	41.03	41.21	41.40	41.65	43.21	43.41
2033	44.55	44.75	44.50	43.34	43.57	43.77	43.94	44.11	44.33	44.74	46.16	46.37
2034	47.55	47.77	46.61	45.27	45.52	45.72	45.91	46.10	46.32	46.57	48.32	48.55
2035	49.78	50.02	48.88	47.49	47.75	47.41	47.60	47.80	48.04	48.54	50.02	50.47
2036	52.05	52.29	51.09	49.62	49.91	49.54	49.74	49.96	50.21	50.73	52.28	52.75
2037	54.46	54.72	53.46	51.93	52.21	51.83	52.04	52.26	52.51	53.09	54.71	55.22
2038	56.95	57.23	55.90	54.28	54.59	54.20	54.41	54.65	54.92	55.52	57.23	57.75
2039	59.60	59.87	58.49	56.80	57.11	56.70	56.93	57.17	57.46	58.09	59.87	60.43
2040	62.34	62.63	61.18	59.39	59.73	59.29	59.54	59.78	60.09	60.75	62.63	63.21
2041	65.26	65.57	64.03	62.15	62.49	62.04	62.29	62.56	62.88	63.58	65.55	66.17
2042	68.31	68.63	67.01	65.04	65.41	64.94	65.18	65.47	65.81	66.54	68.63	69.27

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 18.59%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 15.33%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind and solar QFs (Tables 5a, 5b, 6a, and 6b) include a reduction for the integration costs in Table 7, which cancels out integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind or Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b or 6a and 6b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

Renewable Fixed Price Option (Continued)

TABLE 4a Renewable Avoided Costs Renewable Fixed Price Option for Base Load QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	36.28	36.45	32.07	27.15	25.16	20.76	31.18	33.59	36.96	36.50	36.17	38.88
2026	38.02	38.42	34.69	28.61	23.72	19.90	33.16	36.49	39.07	39.98	39.93	41.34
2027	40.65	40.65	35.03	29.55	25.62	19.81	33.68	38.68	40.37	41.18	39.95	42.49
2028	41.59	39.62	35.61	29.31	24.13	18.69	35.04	39.47	41.56	42.04	42.77	45.50
2029	130.46	122.16	114.93	99.44	91.28	66.74	111.72	123.40	130.72	125.77	127.43	137.59
2030	131.08	128.53	117.83	98.71	84.69	62.99	114.81	124.72	133.57	132.78	130.81	140.19
2031	131.64	130.86	120.44	98.71	91.59	75.33	113.41	127.20	134.67	132.63	129.43	138.99
2032	134.62	132.28	119.05	100.89	89.34	66.65	119.99	136.17	137.32	134.74	138.45	144.33
2033	137.25	136.91	119.61	101.75	86.72	86.02	122.63	133.68	138.82	137.65	139.72	144.28
2034	142.85	142.41	123.71	103.53	88.59	73.28	127.14	137.57	142.77	143.43	144.85	150.81
2035	148.82	142.53	126.90	103.23	91.63	67.83	123.14	139.46	145.86	143.75	142.41	153.08
2036	149.95	144.47	128.97	105.99	82.91	55.60	131.13	142.04	150.30	148.99	147.58	158.25
2037	150.31	149.85	132.81	104.38	91.13	77.19	129.68	144.87	152.33	149.48	149.48	159.99
2038	153.59	155.69	131.34	104.62	84.94	70.00	139.81	155.20	158.10	155.40	156.18	165.33
2039	155.36	153.84	130.69	105.47	94.56	80.72	140.16	151.56	157.69	151.05	155.29	162.46
2040	157.59	155.79	132.79	114.89	87.55	75.00	145.49	156.16	163.50	158.77	161.06	169.93
2041	161.95	158.31	139.08	119.78	109.77	63.50	144.74	159.21	165.49	156.15	156.63	168.47
2042	164.72	162.40	143.32	120.89	93.22	64.66	149.09	163.83	169.34	163.16	161.00	175.92

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 4b
Renewable Avoided Costs
Renewable Fixed Price Option for Base Load QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	33.70	32.17	29.76	25.01	21.99	19.00	26.39	30.90	33.57	33.77	33.61	34.83
2026	35.44	35.59	31.64	27.21	22.20	15.26	28.97	33.61	36.07	35.46	35.51	37.70
2027	36.66	35.71	32.22	27.60	23.64	18.12	29.40	34.72	37.35	37.55	36.31	38.40
2028	38.09	37.21	33.20	27.82	23.65	17.34	31.56	36.38	38.22	38.77	39.08	40.92
2029	87.39	83.14	79.75	60.89	56.60	30.37	68.86	84.70	91.46	89.10	90.05	95.00
2030	90.66	87.81	81.88	62.46	52.25	31.31	75.55	87.01	93.96	93.87	94.23	96.33
2031	94.53	91.33	79.90	66.32	59.86	41.01	74.22	87.92	95.40	93.03	92.05	96.31
2032	95.12	90.63	85.26	64.49	46.09	33.03	81.76	88.62	98.19	95.17	97.79	103.88
2033	96.72	93.73	84.37	65.02	55.14	44.09	81.80	90.25	98.91	96.03	97.55	104.35
2034	100.64	96.93	84.22	63.90	50.21	33.88	82.22	94.26	101.29	101.38	105.38	107.75
2035	103.38	100.59	93.20	71.90	61.31	46.52	81.06	99.14	104.45	99.35	103.56	106.09
2036	111.16	105.72	94.24	72.48	61.23	31.45	82.90	100.58	110.79	104.85	108.44	114.13
2037	110.15	107.49	96.32	79.57	59.61	38.00	86.10	101.85	110.09	103.94	105.91	113.12
2038	113.74	110.37	97.67	79.06	51.82	34.44	88.62	103.26	110.27	107.20	111.44	117.93
2039	110.16	108.78	96.61	84.94	62.94	60.33	93.55	103.97	110.69	110.48	115.32	122.80
2040	116.99	108.93	94.17	91.82	59.51	40.97	95.01	110.61	112.45	116.09	118.19	121.07
2041	116.50	110.73	111.72	97.32	66.46	37.99	97.97	109.98	123.17	113.27	119.57	123.40
2042	126.11	116.45	107.55	85.50	62.50	40.12	105.67	116.39	125.76	123.46	122.21	128.97

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 5a
Renewable Avoided Costs
Renewable Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	35.28	35.45	31.07	26.15	24.16	19.76	30.18	32.59	35.96	35.50	35.17	37.88
2026	37.00	37.40	33.67	27.59	22.70	18.88	32.14	35.47	38.05	38.96	38.91	40.32
2027	39.61	39.61	33.99	28.51	24.58	18.77	32.64	37.64	39.33	40.14	38.91	41.45
2028	40.53	38.56	34.55	28.25	23.07	17.63	33.98	38.41	40.50	40.98	41.71	44.44
2029	113.52	105.21	97.99	82.50	74.34	49.80	94.77	106.45	113.77	108.83	110.48	120.64
2030	113.80	111.24	100.54	81.43	67.41	45.70	97.52	107.44	116.29	115.50	113.53	122.91
2031	114.02	113.23	102.81	81.08	73.97	57.71	95.79	109.57	117.04	115.01	111.80	121.36
2032	116.76	114.41	101.18	83.02	71.47	48.78	102.12	118.30	119.45	116.88	120.58	126.46
2033	118.91	118.57	101.27	83.40	68.38	67.68	104.29	115.34	120.47	119.31	121.38	125.94
2034	124.09	123.65	104.95	84.77	69.82	54.52	108.37	118.81	124.01	124.67	126.09	132.05
2035	129.75	123.46	107.82	84.16	72.56	48.75	104.07	120.39	126.78	124.67	123.33	134.01
2036	130.55	125.06	109.57	86.58	63.51	36.20	111.72	122.63	130.90	129.59	128.17	138.84
2037	130.46	130.00	112.97	84.54	71.28	57.35	109.83	125.02	132.49	129.63	129.63	140.14
2038	133.34	135.44	111.09	84.37	64.69	49.75	119.56	134.95	137.85	135.16	135.93	145.08
2039	134.72	133.19	110.04	84.82	73.91	60.08	119.52	130.91	137.04	130.40	134.64	141.81
2040	136.52	134.72	111.73	93.82	66.49	53.93	124.43	135.10	142.44	137.70	140.00	148.87
2041	140.47	136.82	117.59	98.30	88.28	42.01	123.25	137.72	144.00	134.66	135.14	146.98
2042	142.81	140.48	121.41	98.97	71.31	42.74	127.18	141.92	147.43	141.25	139.09	154.01

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 5b
Renewable Avoided Costs
Renewable Fixed Price Option for Wind QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	32.70	31.17	28.76	24.01	20.99	18.00	25.39	29.90	32.57	32.77	32.61	33.83
2026	34.42	34.57	30.62	26.19	21.18	14.24	27.95	32.59	35.05	34.44	34.49	36.68
2027	35.62	34.67	31.18	26.56	22.60	17.08	28.36	33.68	36.31	36.51	35.27	37.36
2028	37.03	36.15	32.14	26.76	22.59	16.28	30.50	35.32	37.16	37.71	38.02	39.86
2029	86.31	82.06	78.67	59.81	55.52	29.29	67.78	83.62	90.38	88.02	88.97	93.92
2030	89.56	86.71	80.78	61.36	51.15	30.21	74.45	85.91	92.86	92.77	93.13	95.23
2031	93.41	90.21	78.78	65.20	58.74	39.89	73.10	86.80	94.28	91.91	90.93	95.19
2032	93.98	89.49	84.12	63.35	44.95	31.89	80.62	87.48	97.05	94.03	96.65	102.74
2033	95.55	92.56	83.20	63.85	53.97	42.92	80.63	89.08	97.74	94.86	96.38	103.18
2034	99.45	95.74	83.03	62.71	49.02	32.69	81.03	93.07	100.10	100.19	104.19	106.56
2035	102.17	99.38	91.99	70.69	60.10	45.31	79.85	97.93	103.24	98.14	102.35	104.88
2036	109.92	104.48	93.00	71.24	59.99	30.21	81.66	99.34	109.55	103.61	107.20	112.89
2037	108.89	106.23	95.06	78.31	58.35	36.74	84.84	100.59	108.83	102.68	104.65	111.86
2038	112.45	109.08	96.38	77.77	50.53	33.15	87.33	101.97	108.98	105.91	110.15	116.64
2039	108.85	107.47	95.30	83.63	61.63	59.02	92.24	102.66	109.38	109.17	114.01	121.49
2040	115.65	107.59	92.83	90.48	58.17	39.63	93.67	109.27	111.11	114.75	116.85	119.73
2041	115.13	109.36	110.35	95.95	65.09	36.62	96.60	108.61	121.80	111.90	118.20	122.03
2042	124.72	115.06	106.16	84.11	61.11	38.73	104.28	115.00	124.37	122.07	120.82	127.58

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6a												
Renewable Avoided Costs Renewable Fixed Price Option for Solar QF												
On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	35.28	35.45	31.07	26.15	24.16	19.76	30.18	32.59	35.96	35.50	35.17	37.88
2026	37.00	37.40	33.67	27.59	22.70	18.88	32.14	35.47	38.05	38.96	38.91	40.32
2027	39.61	39.61	33.99	28.51	24.58	18.77	32.64	37.64	39.33	40.14	38.91	41.45
2028	40.53	38.56	34.55	28.25	23.07	17.63	33.98	38.41	40.50	40.98	41.71	44.44
2029	110.60	102.29	95.07	79.58	71.42	46.88	91.85	103.54	110.85	105.91	107.56	117.72
2030	110.82	108.27	97.57	78.45	64.43	42.73	94.55	104.46	113.31	112.52	110.55	119.93
2031	110.98	110.19	99.78	78.05	70.93	54.67	92.75	106.54	114.01	111.97	108.77	118.33
2032	113.68	111.33	98.10	79.95	68.40	45.70	99.05	115.22	116.37	113.80	117.51	123.38
2033	115.75	115.41	98.11	80.25	65.22	64.52	101.13	112.18	117.32	116.15	118.22	122.78
2034	120.86	120.42	101.71	81.54	66.59	51.28	105.14	115.58	120.78	121.43	122.86	128.82
2035	126.46	120.17	104.54	80.87	69.27	45.47	100.78	117.10	123.50	121.38	120.05	130.72
2036	127.20	121.72	106.23	83.24	60.16	32.86	108.38	119.29	127.56	126.25	124.83	135.50
2037	127.04	126.58	109.55	81.12	67.86	53.93	106.42	121.60	129.07	126.21	126.21	136.72
2038	129.86	131.95	107.60	80.88	61.20	46.26	116.08	131.46	134.36	131.67	132.45	141.59
2039	131.16	129.64	106.49	81.27	70.35	56.52	115.96	127.36	133.49	126.84	131.09	138.25
2040	132.90	131.10	108.10	90.19	62.86	50.30	120.80	131.47	138.81	134.08	136.37	145.24
2041	136.76	133.12	113.89	94.59	84.58	38.31	119.55	134.02	140.30	130.96	131.44	143.28
2042	139.03	136.71	117.63	95.20	67.53	38.97	123.41	138.15	143.66	137.47	135.31	150.23

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6b Renewable Avoided Costs Renewable Fixed Price Option for Solar QF Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	32.70	31.17	28.76	24.01	20.99	18.00	25.39	29.90	32.57	32.77	32.61	33.83
2026	34.42	34.57	30.62	26.19	21.18	14.24	27.95	32.59	35.05	34.44	34.49	36.68
2027	35.62	34.67	31.18	26.56	22.60	17.08	28.36	33.68	36.31	36.51	35.27	37.36
2028	37.03	36.15	32.14	26.76	22.59	16.28	30.50	35.32	37.16	37.71	38.02	39.86
2029	86.31	82.06	78.67	59.81	55.52	29.29	67.78	83.62	90.38	88.02	88.97	93.92
2030	89.56	86.71	80.78	61.36	51.15	30.21	74.45	85.91	92.86	92.77	93.13	95.23
2031	93.41	90.21	78.78	65.20	58.74	39.89	73.10	86.80	94.28	91.91	90.93	95.19
2032	93.98	89.49	84.12	63.35	44.95	31.89	80.62	87.48	97.05	94.03	96.65	102.74
2033	95.55	92.56	83.20	63.85	53.97	42.92	80.63	89.08	97.74	94.86	96.38	103.18
2034	99.45	95.74	83.03	62.71	49.02	32.69	81.03	93.07	100.10	100.19	104.19	106.56
2035	102.17	99.38	91.99	70.69	60.10	45.31	79.85	97.93	103.24	98.14	102.35	104.88
2036	109.92	104.48	93.00	71.24	59.99	30.21	81.66	99.34	109.55	103.61	107.20	112.89
2037	108.89	106.23	95.06	78.31	58.35	36.74	84.84	100.59	108.83	102.68	104.65	111.86
2038	112.45	109.08	96.38	77.77	50.53	33.15	87.33	101.97	108.98	105.91	110.15	116.64
2039	108.85	107.47	95.30	83.63	61.63	59.02	92.24	102.66	109.38	109.17	114.01	121.49
2040	115.65	107.59	92.83	90.48	58.17	39.63	93.67	109.27	111.11	114.75	116.85	119.73
2041	115.13	109.36	110.35	95.95	65.09	36.62	96.60	108.61	121.80	111.90	118.20	122.03
2042	124.72	115.06	106.16	84.11	61.11	38.73	104.28	115.00	124.37	122.07	120.82	127.58

SCHEDULE 201 (Continued)

WIND AND SOLAR INTEGRATION

TABLE 7		
Integration Costs		
Year	Wind	Solar
2017	0.85	0.85
2018	0.87	0.87
2019	0.88	0.88
2020	0.90	0.90
2021	0.92	0.92
2022	0.94	0.94
2023	0.96	0.96
2024	0.98	0.98
2025	1.00	1.00
2026	1.02	1.02
2027	1.04	1.04
2028	1.06	1.06
2029	1.08	1.08
2030	1.10	1.10
2031	1.12	1.12
2032	1.14	1.14
2033	1.17	1.17
2034	1.19	1.19
2035	1.21	1.21
2036	1.24	1.24
2037	1.26	1.26
2038	1.29	1.29
2039	1.31	1.31
2040	1.34	1.34
2041	1.37	1.37
2042	1.39	1.39

SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged $10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Continued)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.

b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

SCHEDULE 201 (Continued)

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term “Same Person(s)” or “Affiliated Person(s)” means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a “passive investor” whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a “passive investor” in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility’s safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility’s approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange (“ICE”) for the bilateral OTC market for energy at the Mid-C Physical for Average

SCHEDULE 201 (Continued)

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2024.

Definition of Resource Deficiency Period

This is the period from 2025.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2028.

Definition of Renewable Resource Deficiency Period

This is the period from 2029.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

> The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.
>
> The utility may respond to the complaint within ten days of service.
>
> The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.

2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller’s retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.

3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA’s termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

UM 1728 Application to Update
Schedule 201 Qualifying Facility Information

Redlined Version
(*Effective date September 18, 2017*)

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

SCHEDULE 201 (Continued)

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

SCHEDULE 201 (Continued)

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

SCHEDULE 201 (Continued)

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 18.59~~5~~%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be ~~5~~15.33%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind and Solar QFs (Tables 2a, ~~and~~ 2b, 3a, and 3b) include a reduction for the ~~wind~~ integration costs in Table 7. However, if the Wind or Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the ~~wind~~ integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b or 3a and 3b, for a net-zero effect.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

TABLE 1a												
Avoided Costs Standard Fixed Price Option for Base Load QF												
On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	57.28	57.40	57.49	56.78	56.75	56.67	56.77	56.85	56.97	57.07	57.81	57.92
2026	59.17	59.29	59.34	58.62	58.63	58.69	58.79	58.89	59.03	59.16	60.03	60.15
2027	61.01	61.13	61.04	60.30	60.44	60.19	60.29	60.39	60.52	61.27	59.92	60.04
2028	61.23	61.31	61.19	60.52	60.66	60.78	60.88	61.00	61.12	61.26	62.44	62.57
2029	64.03	64.16	64.28	63.58	63.76	64.88	65.00	65.13	65.28	65.40	66.74	66.88
2030	69.60	70.59	70.73	70.05	70.25	70.41	70.56	70.72	70.89	71.77	72.44	72.62
2031	74.30	74.48	74.10	73.00	73.15	73.04	73.18	73.34	73.51	73.69	74.85	75.02
2032	76.53	76.62	76.32	75.09	75.30	75.49	75.64	75.81	76.00	76.25	77.82	78.02
2033	80.07	80.28	80.02	78.86	79.09	79.29	79.46	79.64	79.85	80.26	81.68	81.90
2034	83.89	84.11	82.95	81.61	81.86	82.07	82.25	82.45	82.67	82.91	84.66	84.89
2035	86.73	86.97	85.83	84.45	84.70	84.37	84.55	84.75	84.99	85.49	86.97	87.42
2036	89.63	89.87	88.67	87.20	87.49	87.12	87.32	87.54	87.78	88.31	89.86	90.33
2037	92.90	93.16	91.91	90.37	90.65	90.28	90.48	90.71	90.95	91.53	93.15	93.66
2038	96.17	96.45	95.12	93.50	93.81	93.42	93.63	93.87	94.14	94.74	96.45	96.97
2039	99.60	99.87	98.49	96.79	97.11	96.69	96.92	97.17	97.45	98.09	99.87	100.43
2040	103.14	103.43	101.98	100.19	100.53	100.09	100.34	100.59	100.89	101.55	103.43	104.02
2041	106.88	107.19	105.65	103.77	104.11	103.66	103.92	104.18	104.50	105.20	107.17	107.79
2042	110.75	111.07	109.46	107.49	107.86	107.38	107.63	107.92	108.25	108.98	111.07	111.71

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 1b Avoided Costs Standard Fixed Price Option for Base Load QF Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	27.96	28.08	28.17	27.46	27.43	27.35	27.45	27.53	27.65	27.75	28.49	28.60
2026	29.26	29.39	29.43	28.71	28.72	28.79	28.89	28.99	29.12	29.25	30.12	30.24
2027	30.50	30.63	30.54	29.80	29.94	29.69	29.79	29.89	30.01	30.76	29.41	29.54
2028	30.11	30.19	30.08	29.41	29.55	29.66	29.77	29.88	30.01	30.15	31.33	31.45
2029	32.29	32.42	32.54	31.85	32.02	33.14	33.26	33.39	33.54	33.66	35.01	35.15
2030	37.23	38.22	38.36	37.68	37.88	38.04	38.19	38.35	38.52	39.40	40.07	40.25
2031	41.28	41.46	41.08	39.98	40.13	40.02	40.16	40.32	40.49	40.67	41.83	42.00
2032	43.06	43.15	42.85	41.62	41.84	42.02	42.17	42.35	42.54	42.79	44.35	44.55
2033	45.72	45.92	45.67	44.51	44.74	44.94	45.11	45.28	45.50	45.91	47.33	47.54
2034	48.74	48.96	47.80	46.46	46.71	46.91	47.10	47.29	47.51	47.76	49.51	49.74
2035	50.99	51.23	50.09	48.70	48.96	48.62	48.81	49.01	49.25	49.75	51.23	51.68
2036	53.29	53.53	52.33	50.86	51.15	50.78	50.98	51.20	51.45	51.97	53.52	53.99
2037	55.72	55.98	54.72	53.19	53.47	53.09	53.30	53.52	53.77	54.35	55.97	56.48
2038	58.24	58.52	57.19	55.57	55.88	55.49	55.70	55.94	56.21	56.81	58.52	59.04
2039	60.91	61.18	59.80	58.11	58.42	58.01	58.24	58.48	58.77	59.40	61.18	61.74
2040	63.68	63.97	62.52	60.73	61.07	60.63	60.88	61.12	61.43	62.09	63.97	64.55
2041	66.63	66.94	65.40	63.52	63.86	63.41	63.66	63.93	64.25	64.95	66.92	67.54
2042	69.70	70.02	68.40	66.43	66.80	66.33	66.57	66.86	67.20	67.93	70.02	70.66

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 2a
Avoided Costs
Standard Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	41.62	41.74	41.83	41.12	41.09	41.01	41.11	41.20	41.32	41.42	42.16	42.27
2026	43.20	43.32	43.37	42.65	42.66	42.72	42.82	42.92	43.06	43.19	44.06	44.18
2027	44.72	44.84	44.75	44.02	44.15	43.90	44.00	44.11	44.23	44.98	43.63	43.76
2028	44.62	44.70	44.58	43.91	44.05	44.16	44.27	44.38	44.51	44.65	45.83	45.96
2029	47.09	47.22	47.33	46.64	46.82	47.94	48.05	48.18	48.34	48.45	49.80	49.94
2030	52.32	53.31	53.45	52.77	52.97	53.13	53.28	53.44	53.61	54.49	55.16	55.34
2031	56.67	56.86	56.48	55.37	55.52	55.41	55.56	55.72	55.89	56.06	57.23	57.40
2032	58.66	58.75	58.45	57.22	57.43	57.62	57.77	57.95	58.13	58.38	59.95	60.15
2033	61.73	61.93	61.68	60.52	60.75	60.95	61.12	61.30	61.51	61.92	63.34	63.55
2034	65.13	65.35	64.19	62.85	63.10	63.31	63.49	63.68	63.91	64.15	65.90	66.13
2035	67.65	67.89	66.75	65.37	65.62	65.29	65.48	65.68	65.91	66.42	67.89	68.34
2036	70.22	70.47	69.26	67.80	68.08	67.72	67.92	68.14	68.38	68.91	70.45	70.93
2037	73.05	73.32	72.06	70.53	70.80	70.43	70.64	70.86	71.11	71.69	73.30	73.81
2038	75.92	76.20	74.87	73.25	73.56	73.17	73.38	73.62	73.89	74.49	76.20	76.72
2039	78.95	79.22	77.84	76.15	76.46	76.04	76.27	76.52	76.81	77.44	79.22	79.78
2040	82.07	82.36	80.91	79.13	79.46	79.02	79.27	79.52	79.83	80.49	82.36	82.95
2041	85.39	85.70	84.16	82.28	82.62	82.17	82.43	82.70	83.01	83.71	85.69	86.30
2042	88.84	89.16	87.55	85.58	85.94	85.47	85.72	86.01	86.34	87.07	89.16	89.80

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 2b Avoided Costs Standard Fixed Price Option for Wind QF Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	26.96	27.08	27.17	26.46	26.43	26.35	26.45	26.53	26.65	26.75	27.49	27.60
2026	28.24	28.37	28.41	27.69	27.70	27.77	27.87	27.97	28.10	28.23	29.10	29.22
2027	29.46	29.59	29.50	28.76	28.90	28.65	28.75	28.85	28.97	29.72	28.37	28.50
2028	29.05	29.13	29.02	28.35	28.49	28.60	28.71	28.82	28.95	29.09	30.27	30.39
2029	31.21	31.34	31.46	30.77	30.94	32.06	32.18	32.31	32.46	32.58	33.93	34.07
2030	36.13	37.12	37.26	36.58	36.78	36.94	37.09	37.25	37.42	38.30	38.97	39.15
2031	40.16	40.34	39.96	38.86	39.01	38.90	39.04	39.20	39.37	39.55	40.71	40.88
2032	41.92	42.01	41.71	40.48	40.70	40.88	41.03	41.21	41.40	41.65	43.21	43.41
2033	44.55	44.75	44.50	43.34	43.57	43.77	43.94	44.11	44.33	44.74	46.16	46.37
2034	47.55	47.77	46.61	45.27	45.52	45.72	45.91	46.10	46.32	46.57	48.32	48.55
2035	49.78	50.02	48.88	47.49	47.75	47.41	47.60	47.80	48.04	48.54	50.02	50.47
2036	52.05	52.29	51.09	49.62	49.91	49.54	49.74	49.96	50.21	50.73	52.28	52.75
2037	54.46	54.72	53.46	51.93	52.21	51.83	52.04	52.26	52.51	53.09	54.71	55.22
2038	56.95	57.23	55.90	54.28	54.59	54.20	54.41	54.65	54.92	55.52	57.23	57.75
2039	59.60	59.87	58.49	56.80	57.11	56.70	56.93	57.17	57.46	58.09	59.87	60.43
2040	62.34	62.63	61.18	59.39	59.73	59.29	59.54	59.78	60.09	60.75	62.63	63.21
2041	65.26	65.57	64.03	62.15	62.49	62.04	62.29	62.56	62.88	63.58	65.55	66.17
2042	68.31	68.63	67.01	65.04	65.41	64.94	65.18	65.47	65.81	66.54	68.63	69.27

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3a												
Avoided Costs Standard Fixed Price Option for Solar QF												
On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	38.93	39.05	39.13	38.43	38.39	38.32	38.42	38.50	38.62	38.72	39.46	39.57
2026	40.45	40.57	40.62	39.90	39.91	39.97	40.07	40.17	40.31	40.44	41.31	41.43
2027	41.91	42.04	41.95	41.21	41.35	41.10	41.20	41.30	41.43	42.17	40.83	40.95
2028	41.75	41.84	41.72	41.05	41.19	41.30	41.41	41.52	41.65	41.79	42.97	43.10
2029	44.17	44.30	44.42	43.72	43.90	45.02	45.14	45.27	45.42	45.54	46.88	47.02
2030	49.34	50.33	50.48	49.79	49.99	50.15	50.31	50.46	50.63	51.51	52.18	52.36
2031	53.64	53.82	53.44	52.34	52.49	52.37	52.52	52.68	52.85	53.02	54.19	54.36
2032	55.58	55.67	55.37	54.14	54.36	54.54	54.69	54.87	55.06	55.31	56.87	57.07
2033	58.57	58.78	58.52	57.36	57.59	57.79	57.96	58.14	58.35	58.76	60.18	60.40
2034	61.90	62.12	60.96	59.62	59.87	60.07	60.26	60.45	60.67	60.92	62.66	62.90
2035	64.37	64.61	63.46	62.08	62.34	62.00	62.19	62.39	62.63	63.13	64.61	65.06
2036	66.88	67.12	65.92	64.46	64.74	64.38	64.58	64.80	65.04	65.57	67.11	67.58
2037	69.64	69.90	68.64	67.11	67.38	67.01	67.22	67.44	67.69	68.27	69.88	70.40
2038	72.43	72.71	71.39	69.77	70.08	69.68	69.89	70.13	70.40	71.01	72.71	73.23
2039	75.39	75.66	74.28	72.59	72.90	72.49	72.72	72.96	73.25	73.88	75.66	76.22
2040	78.44	78.74	77.28	75.50	75.83	75.39	75.64	75.89	76.20	76.86	78.74	79.32
2041	81.69	82.00	80.46	78.58	78.92	78.47	78.72	78.99	79.31	80.01	81.98	82.60
2042	85.07	85.39	83.77	81.80	82.17	81.70	81.94	82.23	82.57	83.30	85.39	86.03

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3b
Avoided Costs
Standard Fixed Price Option for Solar QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	26.96	27.08	27.17	26.46	26.43	26.35	26.45	26.53	26.65	26.75	27.49	27.60
2026	28.24	28.37	28.41	27.69	27.70	27.77	27.87	27.97	28.10	28.23	29.10	29.22
2027	29.46	29.59	29.50	28.76	28.90	28.65	28.75	28.85	28.97	29.72	28.37	28.50
2028	29.05	29.13	29.02	28.35	28.49	28.60	28.71	28.82	28.95	29.09	30.27	30.39
2029	31.21	31.34	31.46	30.77	30.94	32.06	32.18	32.31	32.46	32.58	33.93	34.07
2030	36.13	37.12	37.26	36.58	36.78	36.94	37.09	37.25	37.42	38.30	38.97	39.15
2031	40.16	40.34	39.96	38.86	39.01	38.90	39.04	39.20	39.37	39.55	40.71	40.88
2032	41.92	42.01	41.71	40.48	40.70	40.88	41.03	41.21	41.40	41.65	43.21	43.41
2033	44.55	44.75	44.50	43.34	43.57	43.77	43.94	44.11	44.33	44.74	46.16	46.37
2034	47.55	47.77	46.61	45.27	45.52	45.72	45.91	46.10	46.32	46.57	48.32	48.55
2035	49.78	50.02	48.88	47.49	47.75	47.41	47.60	47.80	48.04	48.54	50.02	50.47
2036	52.05	52.29	51.09	49.62	49.91	49.54	49.74	49.96	50.21	50.73	52.28	52.75
2037	54.46	54.72	53.46	51.93	52.21	51.83	52.04	52.26	52.51	53.09	54.71	55.22
2038	56.95	57.23	55.90	54.28	54.59	54.20	54.41	54.65	54.92	55.52	57.23	57.75
2039	59.60	59.87	58.49	56.80	57.11	56.70	56.93	57.17	57.46	58.09	59.87	60.43
2040	62.34	62.63	61.18	59.39	59.73	59.29	59.54	59.78	60.09	60.75	62.63	63.21
2041	65.26	65.57	64.03	62.15	62.49	62.04	62.29	62.56	62.88	63.58	65.55	66.17
2042	68.31	68.63	67.01	65.04	65.41	64.94	65.18	65.47	65.81	66.54	68.63	69.27

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of ~~5~~18.59%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be ~~5~~15.33%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind and solar QFs (Tables 5a, ~~and~~ 5b, 6a, and 6b) include a reduction for the ~~wind~~ integration costs in Table 7, which cancels out ~~wind~~ integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind or Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the ~~wind~~ integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b or 6a and 6b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

Renewable Fixed Price Option (Continued)

TABLE 4a												
Renewable Avoided Costs Renewable Fixed Price Option for Base Load QF												
On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	36.28	36.45	32.07	27.15	25.16	20.76	31.18	33.59	36.96	36.50	36.17	38.88
2026	38.02	38.42	34.69	28.61	23.72	19.90	33.16	36.49	39.07	39.98	39.93	41.34
2027	40.65	40.65	35.03	29.55	25.62	19.81	33.68	38.68	40.37	41.18	39.95	42.49
2028	41.59	39.62	35.61	29.31	24.13	18.69	35.04	39.47	41.56	42.04	42.77	45.50
2029	130.46	122.16	114.93	99.44	91.28	66.74	111.72	123.40	130.72	125.77	127.43	137.59
2030	131.08	128.53	117.83	98.71	84.69	62.99	114.81	124.72	133.57	132.78	130.81	140.19
2031	131.64	130.86	120.44	98.71	91.59	75.33	113.41	127.20	134.67	132.63	129.43	138.99
2032	134.62	132.28	119.05	100.89	89.34	66.65	119.99	136.17	137.32	134.74	138.45	144.33
2033	137.25	136.91	119.61	101.75	86.72	86.02	122.63	133.68	138.82	137.65	139.72	144.28
2034	142.85	142.41	123.71	103.53	88.59	73.28	127.14	137.57	142.77	143.43	144.85	150.81
2035	148.82	142.53	126.90	103.23	91.63	67.83	123.14	139.46	145.86	143.75	142.41	153.08
2036	149.95	144.47	128.97	105.99	82.91	55.60	131.13	142.04	150.30	148.99	147.58	158.25
2037	150.31	149.85	132.81	104.38	91.13	77.19	129.68	144.87	152.33	149.48	149.48	159.99
2038	153.59	155.69	131.34	104.62	84.94	70.00	139.81	155.20	158.10	155.40	156.18	165.33
2039	155.36	153.84	130.69	105.47	94.56	80.72	140.16	151.56	157.69	151.05	155.29	162.46
2040	157.59	155.79	132.79	114.89	87.55	75.00	145.49	156.16	163.50	158.77	161.06	169.93
2041	161.95	158.31	139.08	119.78	109.77	63.50	144.74	159.21	165.49	156.15	156.63	168.47
2042	164.72	162.40	143.32	120.89	93.22	64.66	149.09	163.83	169.34	163.16	161.00	175.92

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 4b Renewable Avoided Costs Renewable Fixed Price Option for Base Load QF Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	33.70	32.17	29.76	25.01	21.99	19.00	26.39	30.90	33.57	33.77	33.61	34.83
2026	35.44	35.59	31.64	27.21	22.20	15.26	28.97	33.61	36.07	35.46	35.51	37.70
2027	36.66	35.71	32.22	27.60	23.64	18.12	29.40	34.72	37.35	37.55	36.31	38.40
2028	38.09	37.21	33.20	27.82	23.65	17.34	31.56	36.38	38.22	38.77	39.08	40.92
2029	87.39	83.14	79.75	60.89	56.60	30.37	68.86	84.70	91.46	89.10	90.05	95.00
2030	90.66	87.81	81.88	62.46	52.25	31.31	75.55	87.01	93.96	93.87	94.23	96.33
2031	94.53	91.33	79.90	66.32	59.86	41.01	74.22	87.92	95.40	93.03	92.05	96.31
2032	95.12	90.63	85.26	64.49	46.09	33.03	81.76	88.62	98.19	95.17	97.79	103.88
2033	96.72	93.73	84.37	65.02	55.14	44.09	81.80	90.25	98.91	96.03	97.55	104.35
2034	100.64	96.93	84.22	63.90	50.21	33.88	82.22	94.26	101.29	101.38	105.38	107.75
2035	103.38	100.59	93.20	71.90	61.31	46.52	81.06	99.14	104.45	99.35	103.56	106.09
2036	111.16	105.72	94.24	72.48	61.23	31.45	82.90	100.58	110.79	104.85	108.44	114.13
2037	110.15	107.49	96.32	79.57	59.61	38.00	86.10	101.85	110.09	103.94	105.91	113.12
2038	113.74	110.37	97.67	79.06	51.82	34.44	88.62	103.26	110.27	107.20	111.44	117.93
2039	110.16	108.78	96.61	84.94	62.94	60.33	93.55	103.97	110.69	110.48	115.32	122.80
2040	116.99	108.93	94.17	91.82	59.51	40.97	95.01	110.61	112.45	116.09	118.19	121.07
2041	116.50	110.73	111.72	97.32	66.46	37.99	97.97	109.98	123.17	113.27	119.57	123.40
2042	126.11	116.45	107.55	85.50	62.50	40.12	105.67	116.39	125.76	123.46	122.21	128.97

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 5a
Renewable Avoided Costs
Renewable Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	35.28	35.45	31.07	26.15	24.16	19.76	30.18	32.59	35.96	35.50	35.17	37.88
2026	37.00	37.40	33.67	27.59	22.70	18.88	32.14	35.47	38.05	38.96	38.91	40.32
2027	39.61	39.61	33.99	28.51	24.58	18.77	32.64	37.64	39.33	40.14	38.91	41.45
2028	40.53	38.56	34.55	28.25	23.07	17.63	33.98	38.41	40.50	40.98	41.71	44.44
2029	113.52	105.21	97.99	82.50	74.34	49.80	94.77	106.45	113.77	108.83	110.48	120.64
2030	113.80	111.24	100.54	81.43	67.41	45.70	97.52	107.44	116.29	115.50	113.53	122.91
2031	114.02	113.23	102.81	81.08	73.97	57.71	95.79	109.57	117.04	115.01	111.80	121.36
2032	116.76	114.41	101.18	83.02	71.47	48.78	102.12	118.30	119.45	116.88	120.58	126.46
2033	118.91	118.57	101.27	83.40	68.38	67.68	104.29	115.34	120.47	119.31	121.38	125.94
2034	124.09	123.65	104.95	84.77	69.82	54.52	108.37	118.81	124.01	124.67	126.09	132.05
2035	129.75	123.46	107.82	84.16	72.56	48.75	104.07	120.39	126.78	124.67	123.33	134.01
2036	130.55	125.06	109.57	86.58	63.51	36.20	111.72	122.63	130.90	129.59	128.17	138.84
2037	130.46	130.00	112.97	84.54	71.28	57.35	109.83	125.02	132.49	129.63	129.63	140.14
2038	133.34	135.44	111.09	84.37	64.69	49.75	119.56	134.95	137.85	135.16	135.93	145.08
2039	134.72	133.19	110.04	84.82	73.91	60.08	119.52	130.91	137.04	130.40	134.64	141.81
2040	136.52	134.72	111.73	93.82	66.49	53.93	124.43	135.10	142.44	137.70	140.00	148.87
2041	140.47	136.82	117.59	98.30	88.28	42.01	123.25	137.72	144.00	134.66	135.14	146.98
2042	142.81	140.48	121.41	98.97	71.31	42.74	127.18	141.92	147.43	141.25	139.09	154.01

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 5b
Renewable Avoided Costs
Renewable Fixed Price Option for Wind QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	32.70	31.17	28.76	24.01	20.99	18.00	25.39	29.90	32.57	32.77	32.61	33.83
2026	34.42	34.57	30.62	26.19	21.18	14.24	27.95	32.59	35.05	34.44	34.49	36.68
2027	35.62	34.67	31.18	26.56	22.60	17.08	28.36	33.68	36.31	36.51	35.27	37.36
2028	37.03	36.15	32.14	26.76	22.59	16.28	30.50	35.32	37.16	37.71	38.02	39.86
2029	86.31	82.06	78.67	59.81	55.52	29.29	67.78	83.62	90.38	88.02	88.97	93.92
2030	89.56	86.71	80.78	61.36	51.15	30.21	74.45	85.91	92.86	92.77	93.13	95.23
2031	93.41	90.21	78.78	65.20	58.74	39.89	73.10	86.80	94.28	91.91	90.93	95.19
2032	93.98	89.49	84.12	63.35	44.95	31.89	80.62	87.48	97.05	94.03	96.65	102.74
2033	95.55	92.56	83.20	63.85	53.97	42.92	80.63	89.08	97.74	94.86	96.38	103.18
2034	99.45	95.74	83.03	62.71	49.02	32.69	81.03	93.07	100.10	100.19	104.19	106.56
2035	102.17	99.38	91.99	70.69	60.10	45.31	79.85	97.93	103.24	98.14	102.35	104.88
2036	109.92	104.48	93.00	71.24	59.99	30.21	81.66	99.34	109.55	103.61	107.20	112.89
2037	108.89	106.23	95.06	78.31	58.35	36.74	84.84	100.59	108.83	102.68	104.65	111.86
2038	112.45	109.08	96.38	77.77	50.53	33.15	87.33	101.97	108.98	105.91	110.15	116.64
2039	108.85	107.47	95.30	83.63	61.63	59.02	92.24	102.66	109.38	109.17	114.01	121.49
2040	115.65	107.59	92.83	90.48	58.17	39.63	93.67	109.27	111.11	114.75	116.85	119.73
2041	115.13	109.36	110.35	95.95	65.09	36.62	96.60	108.61	121.80	111.90	118.20	122.03
2042	124.72	115.06	106.16	84.11	61.11	38.73	104.28	115.00	124.37	122.07	120.82	127.58

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6a
Renewable Avoided Costs
Renewable Fixed Price Option for Solar QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	35.28	35.45	31.07	26.15	24.16	19.76	30.18	32.59	35.96	35.50	35.17	37.88
2026	37.00	37.40	33.67	27.59	22.70	18.88	32.14	35.47	38.05	38.96	38.91	40.32
2027	39.61	39.61	33.99	28.51	24.58	18.77	32.64	37.64	39.33	40.14	38.91	41.45
2028	40.53	38.56	34.55	28.25	23.07	17.63	33.98	38.41	40.50	40.98	41.71	44.44
2029	110.60	102.29	95.07	79.58	71.42	46.88	91.85	103.54	110.85	105.91	107.56	117.72
2030	110.82	108.27	97.57	78.45	64.43	42.73	94.55	104.46	113.31	112.52	110.55	119.93
2031	110.98	110.19	99.78	78.05	70.93	54.67	92.75	106.54	114.01	111.97	108.77	118.33
2032	113.68	111.33	98.10	79.95	68.40	45.70	99.05	115.22	116.37	113.80	117.51	123.38
2033	115.75	115.41	98.11	80.25	65.22	64.52	101.13	112.18	117.32	116.15	118.22	122.78
2034	120.86	120.42	101.71	81.54	66.59	51.28	105.14	115.58	120.78	121.43	122.86	128.82
2035	126.46	120.17	104.54	80.87	69.27	45.47	100.78	117.10	123.50	121.38	120.05	130.72
2036	127.20	121.72	106.23	83.24	60.16	32.86	108.38	119.29	127.56	126.25	124.83	135.50
2037	127.04	126.58	109.55	81.12	67.86	53.93	106.42	121.60	129.07	126.21	126.21	136.72
2038	129.86	131.95	107.60	80.88	61.20	46.26	116.08	131.46	134.36	131.67	132.45	141.59
2039	131.16	129.64	106.49	81.27	70.35	56.52	115.96	127.36	133.49	126.84	131.09	138.25
2040	132.90	131.10	108.10	90.19	62.86	50.30	120.80	131.47	138.81	134.08	136.37	145.24
2041	136.76	133.12	113.89	94.59	84.58	38.31	119.55	134.02	140.30	130.96	131.44	143.28
2042	139.03	136.71	117.63	95.20	67.53	38.97	123.41	138.15	143.66	137.47	135.31	150.23

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6b
Renewable Avoided Costs
Renewable Fixed Price Option for Solar QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	32.70	31.17	28.76	24.01	20.99	18.00	25.39	29.90	32.57	32.77	32.61	33.83
2026	34.42	34.57	30.62	26.19	21.18	14.24	27.95	32.59	35.05	34.44	34.49	36.68
2027	35.62	34.67	31.18	26.56	22.60	17.08	28.36	33.68	36.31	36.51	35.27	37.36
2028	37.03	36.15	32.14	26.76	22.59	16.28	30.50	35.32	37.16	37.71	38.02	39.86
2029	86.31	82.06	78.67	59.81	55.52	29.29	67.78	83.62	90.38	88.02	88.97	93.92
2030	89.56	86.71	80.78	61.36	51.15	30.21	74.45	85.91	92.86	92.77	93.13	95.23
2031	93.41	90.21	78.78	65.20	58.74	39.89	73.10	86.80	94.28	91.91	90.93	95.19
2032	93.98	89.49	84.12	63.35	44.95	31.89	80.62	87.48	97.05	94.03	96.65	102.74
2033	95.55	92.56	83.20	63.85	53.97	42.92	80.63	89.08	97.74	94.86	96.38	103.18
2034	99.45	95.74	83.03	62.71	49.02	32.69	81.03	93.07	100.10	100.19	104.19	106.56
2035	102.17	99.38	91.99	70.69	60.10	45.31	79.85	97.93	103.24	98.14	102.35	104.88
2036	109.92	104.48	93.00	71.24	59.99	30.21	81.66	99.34	109.55	103.61	107.20	112.89
2037	108.89	106.23	95.06	78.31	58.35	36.74	84.84	100.59	108.83	102.68	104.65	111.86
2038	112.45	109.08	96.38	77.77	50.53	33.15	87.33	101.97	108.98	105.91	110.15	116.64
2039	108.85	107.47	95.30	83.63	61.63	59.02	92.24	102.66	109.38	109.17	114.01	121.49
2040	115.65	107.59	92.83	90.48	58.17	39.63	93.67	109.27	111.11	114.75	116.85	119.73
2041	115.13	109.36	110.35	95.95	65.09	36.62	96.60	108.61	121.80	111.90	118.20	122.03
2042	124.72	115.06	106.16	84.11	61.11	38.73	104.28	115.00	124.37	122.07	120.82	127.58

SCHEDULE 201 (Continued)

WIND AND SOLAR INTEGRATION

TABLE 7		
Integration Costs		
Year	**Wind**	**Solar**
2017	0.85	0.85
2018	0.87	0.87
2019	0.88	0.88
2020	0.90	0.90
2021	0.92	0.92
2022	0.94	0.94
2023	0.96	0.96
2024	0.98	0.98
2025	1.00	1.00
2026	1.02	1.02
2027	1.04	1.04
2028	1.06	1.06
2029	1.08	1.08
2030	1.10	1.10
2031	1.12	1.12
2032	1.14	1.14
2033	1.17	1.17
2034	1.19	1.19
2035	1.21	1.21
2036	1.24	1.24
2037	1.26	1.26
2038	1.29	1.29
2039	1.31	1.31
2040	1.34	1.34
2041	1.37	1.37
2042	1.39	1.39

SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged $10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Continued)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.

b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

SCHEDULE 201 (Continued)

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

SCHEDULE 201 (Continued)

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through ~~2020~~2024.

Definition of Resource Deficiency Period

This is the period from 202~~1 through 2034~~5.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through ~~2019~~2028.

Definition of Renewable Resource Deficiency Period

This is the period from 202~~0 through 2034~~9.

Effective for service
on and after September 18, 2017~~June 1, 2017~~

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

> The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.
>
> The utility may respond to the complaint within ten days of service.
>
> The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.

2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.

3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

UM 1728 Application to Update Schedule 201 Qualifying Facility Information

Alternative Version
(*Effective date August 8, 2017*)

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

SCHEDULE 201 (Continued)

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

SCHEDULE 201 (Continued)

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

SCHEDULE 201 (Continued)

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) Standard Fixed Price Option

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 18.59%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 15.33%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind and Solar QFs (Tables 2a, 2b, 3a, and 3b) include a reduction for the integration costs in Table 7. However, if the Wind or Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b or 3a and 3b, for a net-zero effect.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

TABLE 1a
Avoided Costs
Standard Fixed Price Option for Base Load QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	57.28	57.40	57.49	56.78	56.75	56.67	56.77	56.85	56.97	57.07	57.81	57.92
2026	59.17	59.29	59.34	58.62	58.63	58.69	58.79	58.89	59.03	59.16	60.03	60.15
2027	61.01	61.13	61.04	60.30	60.44	60.19	60.29	60.39	60.52	61.27	59.92	60.04
2028	61.23	61.31	61.19	60.52	60.66	60.78	60.88	61.00	61.12	61.26	62.44	62.57
2029	64.03	64.16	64.28	63.58	63.76	64.88	65.00	65.13	65.28	65.40	66.74	66.88
2030	69.60	70.59	70.73	70.05	70.25	70.41	70.56	70.72	70.89	71.77	72.44	72.62
2031	74.30	74.48	74.10	73.00	73.15	73.04	73.18	73.34	73.51	73.69	74.85	75.02
2032	76.53	76.62	76.32	75.09	75.30	75.49	75.64	75.81	76.00	76.25	77.82	78.02
2033	80.07	80.28	80.02	78.86	79.09	79.29	79.46	79.64	79.85	80.26	81.68	81.90
2034	83.89	84.11	82.95	81.61	81.86	82.07	82.25	82.45	82.67	82.91	84.66	84.89
2035	86.73	86.97	85.83	84.45	84.70	84.37	84.55	84.75	84.99	85.49	86.97	87.42
2036	89.63	89.87	88.67	87.20	87.49	87.12	87.32	87.54	87.78	88.31	89.86	90.33
2037	92.90	93.16	91.91	90.37	90.65	90.28	90.48	90.71	90.95	91.53	93.15	93.66
2038	96.17	96.45	95.12	93.50	93.81	93.42	93.63	93.87	94.14	94.74	96.45	96.97
2039	99.60	99.87	98.49	96.79	97.11	96.69	96.92	97.17	97.45	98.09	99.87	100.43
2040	103.14	103.43	101.98	100.19	100.53	100.09	100.34	100.59	100.89	101.55	103.43	104.02
2041	106.88	107.19	105.65	103.77	104.11	103.66	103.92	104.18	104.50	105.20	107.17	107.79
2042	110.75	111.07	109.46	107.49	107.86	107.38	107.63	107.92	108.25	108.98	111.07	111.71

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 1b												
Avoided Costs Standard Fixed Price Option for Base Load QF												
Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	27.96	28.08	28.17	27.46	27.43	27.35	27.45	27.53	27.65	27.75	28.49	28.60
2026	29.26	29.39	29.43	28.71	28.72	28.79	28.89	28.99	29.12	29.25	30.12	30.24
2027	30.50	30.63	30.54	29.80	29.94	29.69	29.79	29.89	30.01	30.76	29.41	29.54
2028	30.11	30.19	30.08	29.41	29.55	29.66	29.77	29.88	30.01	30.15	31.33	31.45
2029	32.29	32.42	32.54	31.85	32.02	33.14	33.26	33.39	33.54	33.66	35.01	35.15
2030	37.23	38.22	38.36	37.68	37.88	38.04	38.19	38.35	38.52	39.40	40.07	40.25
2031	41.28	41.46	41.08	39.98	40.13	40.02	40.16	40.32	40.49	40.67	41.83	42.00
2032	43.06	43.15	42.85	41.62	41.84	42.02	42.17	42.35	42.54	42.79	44.35	44.55
2033	45.72	45.92	45.67	44.51	44.74	44.94	45.11	45.28	45.50	45.91	47.33	47.54
2034	48.74	48.96	47.80	46.46	46.71	46.91	47.10	47.29	47.51	47.76	49.51	49.74
2035	50.99	51.23	50.09	48.70	48.96	48.62	48.81	49.01	49.25	49.75	51.23	51.68
2036	53.29	53.53	52.33	50.86	51.15	50.78	50.98	51.20	51.45	51.97	53.52	53.99
2037	55.72	55.98	54.72	53.19	53.47	53.09	53.30	53.52	53.77	54.35	55.97	56.48
2038	58.24	58.52	57.19	55.57	55.88	55.49	55.70	55.94	56.21	56.81	58.52	59.04
2039	60.91	61.18	59.80	58.11	58.42	58.01	58.24	58.48	58.77	59.40	61.18	61.74
2040	63.68	63.97	62.52	60.73	61.07	60.63	60.88	61.12	61.43	62.09	63.97	64.55
2041	66.63	66.94	65.40	63.52	63.86	63.41	63.66	63.93	64.25	64.95	66.92	67.54
2042	69.70	70.02	68.40	66.43	66.80	66.33	66.57	66.86	67.20	67.93	70.02	70.66

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 2a
Avoided Costs
Standard Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	41.62	41.74	41.83	41.12	41.09	41.01	41.11	41.20	41.32	41.42	42.16	42.27
2026	43.20	43.32	43.37	42.65	42.66	42.72	42.82	42.92	43.06	43.19	44.06	44.18
2027	44.72	44.84	44.75	44.02	44.15	43.90	44.00	44.11	44.23	44.98	43.63	43.76
2028	44.62	44.70	44.58	43.91	44.05	44.16	44.27	44.38	44.51	44.65	45.83	45.96
2029	47.09	47.22	47.33	46.64	46.82	47.94	48.05	48.18	48.34	48.45	49.80	49.94
2030	52.32	53.31	53.45	52.77	52.97	53.13	53.28	53.44	53.61	54.49	55.16	55.34
2031	56.67	56.86	56.48	55.37	55.52	55.41	55.56	55.72	55.89	56.06	57.23	57.40
2032	58.66	58.75	58.45	57.22	57.43	57.62	57.77	57.95	58.13	58.38	59.95	60.15
2033	61.73	61.93	61.68	60.52	60.75	60.95	61.12	61.30	61.51	61.92	63.34	63.55
2034	65.13	65.35	64.19	62.85	63.10	63.31	63.49	63.68	63.91	64.15	65.90	66.13
2035	67.65	67.89	66.75	65.37	65.62	65.29	65.48	65.68	65.91	66.42	67.89	68.34
2036	70.22	70.47	69.26	67.80	68.08	67.72	67.92	68.14	68.38	68.91	70.45	70.93
2037	73.05	73.32	72.06	70.53	70.80	70.43	70.64	70.86	71.11	71.69	73.30	73.81
2038	75.92	76.20	74.87	73.25	73.56	73.17	73.38	73.62	73.89	74.49	76.20	76.72
2039	78.95	79.22	77.84	76.15	76.46	76.04	76.27	76.52	76.81	77.44	79.22	79.78
2040	82.07	82.36	80.91	79.13	79.46	79.02	79.27	79.52	79.83	80.49	82.36	82.95
2041	85.39	85.70	84.16	82.28	82.62	82.17	82.43	82.70	83.01	83.71	85.69	86.30
2042	88.84	89.16	87.55	85.58	85.94	85.47	85.72	86.01	86.34	87.07	89.16	89.80

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 2b
Avoided Costs
Standard Fixed Price Option for Wind QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	26.96	27.08	27.17	26.46	26.43	26.35	26.45	26.53	26.65	26.75	27.49	27.60
2026	28.24	28.37	28.41	27.69	27.70	27.77	27.87	27.97	28.10	28.23	29.10	29.22
2027	29.46	29.59	29.50	28.76	28.90	28.65	28.75	28.85	28.97	29.72	28.37	28.50
2028	29.05	29.13	29.02	28.35	28.49	28.60	28.71	28.82	28.95	29.09	30.27	30.39
2029	31.21	31.34	31.46	30.77	30.94	32.06	32.18	32.31	32.46	32.58	33.93	34.07
2030	36.13	37.12	37.26	36.58	36.78	36.94	37.09	37.25	37.42	38.30	38.97	39.15
2031	40.16	40.34	39.96	38.86	39.01	38.90	39.04	39.20	39.37	39.55	40.71	40.88
2032	41.92	42.01	41.71	40.48	40.70	40.88	41.03	41.21	41.40	41.65	43.21	43.41
2033	44.55	44.75	44.50	43.34	43.57	43.77	43.94	44.11	44.33	44.74	46.16	46.37
2034	47.55	47.77	46.61	45.27	45.52	45.72	45.91	46.10	46.32	46.57	48.32	48.55
2035	49.78	50.02	48.88	47.49	47.75	47.41	47.60	47.80	48.04	48.54	50.02	50.47
2036	52.05	52.29	51.09	49.62	49.91	49.54	49.74	49.96	50.21	50.73	52.28	52.75
2037	54.46	54.72	53.46	51.93	52.21	51.83	52.04	52.26	52.51	53.09	54.71	55.22
2038	56.95	57.23	55.90	54.28	54.59	54.20	54.41	54.65	54.92	55.52	57.23	57.75
2039	59.60	59.87	58.49	56.80	57.11	56.70	56.93	57.17	57.46	58.09	59.87	60.43
2040	62.34	62.63	61.18	59.39	59.73	59.29	59.54	59.78	60.09	60.75	62.63	63.21
2041	65.26	65.57	64.03	62.15	62.49	62.04	62.29	62.56	62.88	63.58	65.55	66.17
2042	68.31	68.63	67.01	65.04	65.41	64.94	65.18	65.47	65.81	66.54	68.63	69.27

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3a
Avoided Costs
Standard Fixed Price Option for Solar QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	38.93	39.05	39.13	38.43	38.39	38.32	38.42	38.50	38.62	38.72	39.46	39.57
2026	40.45	40.57	40.62	39.90	39.91	39.97	40.07	40.17	40.31	40.44	41.31	41.43
2027	41.91	42.04	41.95	41.21	41.35	41.10	41.20	41.30	41.43	42.17	40.83	40.95
2028	41.75	41.84	41.72	41.05	41.19	41.30	41.41	41.52	41.65	41.79	42.97	43.10
2029	44.17	44.30	44.42	43.72	43.90	45.02	45.14	45.27	45.42	45.54	46.88	47.02
2030	49.34	50.33	50.48	49.79	49.99	50.15	50.31	50.46	50.63	51.51	52.18	52.36
2031	53.64	53.82	53.44	52.34	52.49	52.37	52.52	52.68	52.85	53.02	54.19	54.36
2032	55.58	55.67	55.37	54.14	54.36	54.54	54.69	54.87	55.06	55.31	56.87	57.07
2033	58.57	58.78	58.52	57.36	57.59	57.79	57.96	58.14	58.35	58.76	60.18	60.40
2034	61.90	62.12	60.96	59.62	59.87	60.07	60.26	60.45	60.67	60.92	62.66	62.90
2035	64.37	64.61	63.46	62.08	62.34	62.00	62.19	62.39	62.63	63.13	64.61	65.06
2036	66.88	67.12	65.92	64.46	64.74	64.38	64.58	64.80	65.04	65.57	67.11	67.58
2037	69.64	69.90	68.64	67.11	67.38	67.01	67.22	67.44	67.69	68.27	69.88	70.40
2038	72.43	72.71	71.39	69.77	70.08	69.68	69.89	70.13	70.40	71.01	72.71	73.23
2039	75.39	75.66	74.28	72.59	72.90	72.49	72.72	72.96	73.25	73.88	75.66	76.22
2040	78.44	78.74	77.28	75.50	75.83	75.39	75.64	75.89	76.20	76.86	78.74	79.32
2041	81.69	82.00	80.46	78.58	78.92	78.47	78.72	78.99	79.31	80.01	81.98	82.60
2042	85.07	85.39	83.77	81.80	82.17	81.70	81.94	82.23	82.57	83.30	85.39	86.03

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3b												
Avoided Costs Standard Fixed Price Option for Solar QF												
Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	26.96	27.08	27.17	26.46	26.43	26.35	26.45	26.53	26.65	26.75	27.49	27.60
2026	28.24	28.37	28.41	27.69	27.70	27.77	27.87	27.97	28.10	28.23	29.10	29.22
2027	29.46	29.59	29.50	28.76	28.90	28.65	28.75	28.85	28.97	29.72	28.37	28.50
2028	29.05	29.13	29.02	28.35	28.49	28.60	28.71	28.82	28.95	29.09	30.27	30.39
2029	31.21	31.34	31.46	30.77	30.94	32.06	32.18	32.31	32.46	32.58	33.93	34.07
2030	36.13	37.12	37.26	36.58	36.78	36.94	37.09	37.25	37.42	38.30	38.97	39.15
2031	40.16	40.34	39.96	38.86	39.01	38.90	39.04	39.20	39.37	39.55	40.71	40.88
2032	41.92	42.01	41.71	40.48	40.70	40.88	41.03	41.21	41.40	41.65	43.21	43.41
2033	44.55	44.75	44.50	43.34	43.57	43.77	43.94	44.11	44.33	44.74	46.16	46.37
2034	47.55	47.77	46.61	45.27	45.52	45.72	45.91	46.10	46.32	46.57	48.32	48.55
2035	49.78	50.02	48.88	47.49	47.75	47.41	47.60	47.80	48.04	48.54	50.02	50.47
2036	52.05	52.29	51.09	49.62	49.91	49.54	49.74	49.96	50.21	50.73	52.28	52.75
2037	54.46	54.72	53.46	51.93	52.21	51.83	52.04	52.26	52.51	53.09	54.71	55.22
2038	56.95	57.23	55.90	54.28	54.59	54.20	54.41	54.65	54.92	55.52	57.23	57.75
2039	59.60	59.87	58.49	56.80	57.11	56.70	56.93	57.17	57.46	58.09	59.87	60.43
2040	62.34	62.63	61.18	59.39	59.73	59.29	59.54	59.78	60.09	60.75	62.63	63.21
2041	65.26	65.57	64.03	62.15	62.49	62.04	62.29	62.56	62.88	63.58	65.55	66.17
2042	68.31	68.63	67.01	65.04	65.41	64.94	65.18	65.47	65.81	66.54	68.63	69.27

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 18.59%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 15.33%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind and solar QFs (Tables 5a, 5b, 6a, and 6b) include a reduction for the integration costs in Table 7, which cancels out integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind or Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b or 6a and 6b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

Renewable Fixed Price Option (Continued)

TABLE 4a
Renewable Avoided Costs
Renewable Fixed Price Option for Base Load QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	36.28	36.45	32.07	27.15	25.16	20.76	31.18	33.59	36.96	36.50	36.17	38.88
2026	38.02	38.42	34.69	28.61	23.72	19.90	33.16	36.49	39.07	39.98	39.93	41.34
2027	40.65	40.65	35.03	29.55	25.62	19.81	33.68	38.68	40.37	41.18	39.95	42.49
2028	41.59	39.62	35.61	29.31	24.13	18.69	35.04	39.47	41.56	42.04	42.77	45.50
2029	130.46	122.16	114.93	99.44	91.28	66.74	111.72	123.40	130.72	125.77	127.43	137.59
2030	131.08	128.53	117.83	98.71	84.69	62.99	114.81	124.72	133.57	132.78	130.81	140.19
2031	131.64	130.86	120.44	98.71	91.59	75.33	113.41	127.20	134.67	132.63	129.43	138.99
2032	134.62	132.28	119.05	100.89	89.34	66.65	119.99	136.17	137.32	134.74	138.45	144.33
2033	137.25	136.91	119.61	101.75	86.72	86.02	122.63	133.68	138.82	137.65	139.72	144.28
2034	142.85	142.41	123.71	103.53	88.59	73.28	127.14	137.57	142.77	143.43	144.85	150.81
2035	148.82	142.53	126.90	103.23	91.63	67.83	123.14	139.46	145.86	143.75	142.41	153.08
2036	149.95	144.47	128.97	105.99	82.91	55.60	131.13	142.04	150.30	148.99	147.58	158.25
2037	150.31	149.85	132.81	104.38	91.13	77.19	129.68	144.87	152.33	149.48	149.48	159.99
2038	153.59	155.69	131.34	104.62	84.94	70.00	139.81	155.20	158.10	155.40	156.18	165.33
2039	155.36	153.84	130.69	105.47	94.56	80.72	140.16	151.56	157.69	151.05	155.29	162.46
2040	157.59	155.79	132.79	114.89	87.55	75.00	145.49	156.16	163.50	158.77	161.06	169.93
2041	161.95	158.31	139.08	119.78	109.77	63.50	144.74	159.21	165.49	156.15	156.63	168.47
2042	164.72	162.40	143.32	120.89	93.22	64.66	149.09	163.83	169.34	163.16	161.00	175.92

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 4b
Renewable Avoided Costs
Renewable Fixed Price Option for Base Load QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	33.70	32.17	29.76	25.01	21.99	19.00	26.39	30.90	33.57	33.77	33.61	34.83
2026	35.44	35.59	31.64	27.21	22.20	15.26	28.97	33.61	36.07	35.46	35.51	37.70
2027	36.66	35.71	32.22	27.60	23.64	18.12	29.40	34.72	37.35	37.55	36.31	38.40
2028	38.09	37.21	33.20	27.82	23.65	17.34	31.56	36.38	38.22	38.77	39.08	40.92
2029	87.39	83.14	79.75	60.89	56.60	30.37	68.86	84.70	91.46	89.10	90.05	95.00
2030	90.66	87.81	81.88	62.46	52.25	31.31	75.55	87.01	93.96	93.87	94.23	96.33
2031	94.53	91.33	79.90	66.32	59.86	41.01	74.22	87.92	95.40	93.03	92.05	96.31
2032	95.12	90.63	85.26	64.49	46.09	33.03	81.76	88.62	98.19	95.17	97.79	103.88
2033	96.72	93.73	84.37	65.02	55.14	44.09	81.80	90.25	98.91	96.03	97.55	104.35
2034	100.64	96.93	84.22	63.90	50.21	33.88	82.22	94.26	101.29	101.38	105.38	107.75
2035	103.38	100.59	93.20	71.90	61.31	46.52	81.06	99.14	104.45	99.35	103.56	106.09
2036	111.16	105.72	94.24	72.48	61.23	31.45	82.90	100.58	110.79	104.85	108.44	114.13
2037	110.15	107.49	96.32	79.57	59.61	38.00	86.10	101.85	110.09	103.94	105.91	113.12
2038	113.74	110.37	97.67	79.06	51.82	34.44	88.62	103.26	110.27	107.20	111.44	117.93
2039	110.16	108.78	96.61	84.94	62.94	60.33	93.55	103.97	110.69	110.48	115.32	122.80
2040	116.99	108.93	94.17	91.82	59.51	40.97	95.01	110.61	112.45	116.09	118.19	121.07
2041	116.50	110.73	111.72	97.32	66.46	37.99	97.97	109.98	123.17	113.27	119.57	123.40
2042	126.11	116.45	107.55	85.50	62.50	40.12	105.67	116.39	125.76	123.46	122.21	128.97

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 5a
Renewable Avoided Costs
Renewable Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	35.28	35.45	31.07	26.15	24.16	19.76	30.18	32.59	35.96	35.50	35.17	37.88
2026	37.00	37.40	33.67	27.59	22.70	18.88	32.14	35.47	38.05	38.96	38.91	40.32
2027	39.61	39.61	33.99	28.51	24.58	18.77	32.64	37.64	39.33	40.14	38.91	41.45
2028	40.53	38.56	34.55	28.25	23.07	17.63	33.98	38.41	40.50	40.98	41.71	44.44
2029	113.52	105.21	97.99	82.50	74.34	49.80	94.77	106.45	113.77	108.83	110.48	120.64
2030	113.80	111.24	100.54	81.43	67.41	45.70	97.52	107.44	116.29	115.50	113.53	122.91
2031	114.02	113.23	102.81	81.08	73.97	57.71	95.79	109.57	117.04	115.01	111.80	121.36
2032	116.76	114.41	101.18	83.02	71.47	48.78	102.12	118.30	119.45	116.88	120.58	126.46
2033	118.91	118.57	101.27	83.40	68.38	67.68	104.29	115.34	120.47	119.31	121.38	125.94
2034	124.09	123.65	104.95	84.77	69.82	54.52	108.37	118.81	124.01	124.67	126.09	132.05
2035	129.75	123.46	107.82	84.16	72.56	48.75	104.07	120.39	126.78	124.67	123.33	134.01
2036	130.55	125.06	109.57	86.58	63.51	36.20	111.72	122.63	130.90	129.59	128.17	138.84
2037	130.46	130.00	112.97	84.54	71.28	57.35	109.83	125.02	132.49	129.63	129.63	140.14
2038	133.34	135.44	111.09	84.37	64.69	49.75	119.56	134.95	137.85	135.16	135.93	145.08
2039	134.72	133.19	110.04	84.82	73.91	60.08	119.52	130.91	137.04	130.40	134.64	141.81
2040	136.52	134.72	111.73	93.82	66.49	53.93	124.43	135.10	142.44	137.70	140.00	148.87
2041	140.47	136.82	117.59	98.30	88.28	42.01	123.25	137.72	144.00	134.66	135.14	146.98
2042	142.81	140.48	121.41	98.97	71.31	42.74	127.18	141.92	147.43	141.25	139.09	154.01

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 5b
Renewable Avoided Costs
Renewable Fixed Price Option for Wind QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	32.70	31.17	28.76	24.01	20.99	18.00	25.39	29.90	32.57	32.77	32.61	33.83
2026	34.42	34.57	30.62	26.19	21.18	14.24	27.95	32.59	35.05	34.44	34.49	36.68
2027	35.62	34.67	31.18	26.56	22.60	17.08	28.36	33.68	36.31	36.51	35.27	37.36
2028	37.03	36.15	32.14	26.76	22.59	16.28	30.50	35.32	37.16	37.71	38.02	39.86
2029	86.31	82.06	78.67	59.81	55.52	29.29	67.78	83.62	90.38	88.02	88.97	93.92
2030	89.56	86.71	80.78	61.36	51.15	30.21	74.45	85.91	92.86	92.77	93.13	95.23
2031	93.41	90.21	78.78	65.20	58.74	39.89	73.10	86.80	94.28	91.91	90.93	95.19
2032	93.98	89.49	84.12	63.35	44.95	31.89	80.62	87.48	97.05	94.03	96.65	102.74
2033	95.55	92.56	83.20	63.85	53.97	42.92	80.63	89.08	97.74	94.86	96.38	103.18
2034	99.45	95.74	83.03	62.71	49.02	32.69	81.03	93.07	100.10	100.19	104.19	106.56
2035	102.17	99.38	91.99	70.69	60.10	45.31	79.85	97.93	103.24	98.14	102.35	104.88
2036	109.92	104.48	93.00	71.24	59.99	30.21	81.66	99.34	109.55	103.61	107.20	112.89
2037	108.89	106.23	95.06	78.31	58.35	36.74	84.84	100.59	108.83	102.68	104.65	111.86
2038	112.45	109.08	96.38	77.77	50.53	33.15	87.33	101.97	108.98	105.91	110.15	116.64
2039	108.85	107.47	95.30	83.63	61.63	59.02	92.24	102.66	109.38	109.17	114.01	121.49
2040	115.65	107.59	92.83	90.48	58.17	39.63	93.67	109.27	111.11	114.75	116.85	119.73
2041	115.13	109.36	110.35	95.95	65.09	36.62	96.60	108.61	121.80	111.90	118.20	122.03
2042	124.72	115.06	106.16	84.11	61.11	38.73	104.28	115.00	124.37	122.07	120.82	127.58

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6a												
Renewable Avoided Costs Renewable Fixed Price Option for Solar QF												
On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	35.28	35.45	31.07	26.15	24.16	19.76	30.18	32.59	35.96	35.50	35.17	37.88
2026	37.00	37.40	33.67	27.59	22.70	18.88	32.14	35.47	38.05	38.96	38.91	40.32
2027	39.61	39.61	33.99	28.51	24.58	18.77	32.64	37.64	39.33	40.14	38.91	41.45
2028	40.53	38.56	34.55	28.25	23.07	17.63	33.98	38.41	40.50	40.98	41.71	44.44
2029	110.60	102.29	95.07	79.58	71.42	46.88	91.85	103.54	110.85	105.91	107.56	117.72
2030	110.82	108.27	97.57	78.45	64.43	42.73	94.55	104.46	113.31	112.52	110.55	119.93
2031	110.98	110.19	99.78	78.05	70.93	54.67	92.75	106.54	114.01	111.97	108.77	118.33
2032	113.68	111.33	98.10	79.95	68.40	45.70	99.05	115.22	116.37	113.80	117.51	123.38
2033	115.75	115.41	98.11	80.25	65.22	64.52	101.13	112.18	117.32	116.15	118.22	122.78
2034	120.86	120.42	101.71	81.54	66.59	51.28	105.14	115.58	120.78	121.43	122.86	128.82
2035	126.46	120.17	104.54	80.87	69.27	45.47	100.78	117.10	123.50	121.38	120.05	130.72
2036	127.20	121.72	106.23	83.24	60.16	32.86	108.38	119.29	127.56	126.25	124.83	135.50
2037	127.04	126.58	109.55	81.12	67.86	53.93	106.42	121.60	129.07	126.21	126.21	136.72
2038	129.86	131.95	107.60	80.88	61.20	46.26	116.08	131.46	134.36	131.67	132.45	141.59
2039	131.16	129.64	106.49	81.27	70.35	56.52	115.96	127.36	133.49	126.84	131.09	138.25
2040	132.90	131.10	108.10	90.19	62.86	50.30	120.80	131.47	138.81	134.08	136.37	145.24
2041	136.76	133.12	113.89	94.59	84.58	38.31	119.55	134.02	140.30	130.96	131.44	143.28
2042	139.03	136.71	117.63	95.20	67.53	38.97	123.41	138.15	143.66	137.47	135.31	150.23

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6b
Renewable Avoided Costs
Renewable Fixed Price Option for Solar QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	32.70	31.17	28.76	24.01	20.99	18.00	25.39	29.90	32.57	32.77	32.61	33.83
2026	34.42	34.57	30.62	26.19	21.18	14.24	27.95	32.59	35.05	34.44	34.49	36.68
2027	35.62	34.67	31.18	26.56	22.60	17.08	28.36	33.68	36.31	36.51	35.27	37.36
2028	37.03	36.15	32.14	26.76	22.59	16.28	30.50	35.32	37.16	37.71	38.02	39.86
2029	86.31	82.06	78.67	59.81	55.52	29.29	67.78	83.62	90.38	88.02	88.97	93.92
2030	89.56	86.71	80.78	61.36	51.15	30.21	74.45	85.91	92.86	92.77	93.13	95.23
2031	93.41	90.21	78.78	65.20	58.74	39.89	73.10	86.80	94.28	91.91	90.93	95.19
2032	93.98	89.49	84.12	63.35	44.95	31.89	80.62	87.48	97.05	94.03	96.65	102.74
2033	95.55	92.56	83.20	63.85	53.97	42.92	80.63	89.08	97.74	94.86	96.38	103.18
2034	99.45	95.74	83.03	62.71	49.02	32.69	81.03	93.07	100.10	100.19	104.19	106.56
2035	102.17	99.38	91.99	70.69	60.10	45.31	79.85	97.93	103.24	98.14	102.35	104.88
2036	109.92	104.48	93.00	71.24	59.99	30.21	81.66	99.34	109.55	103.61	107.20	112.89
2037	108.89	106.23	95.06	78.31	58.35	36.74	84.84	100.59	108.83	102.68	104.65	111.86
2038	112.45	109.08	96.38	77.77	50.53	33.15	87.33	101.97	108.98	105.91	110.15	116.64
2039	108.85	107.47	95.30	83.63	61.63	59.02	92.24	102.66	109.38	109.17	114.01	121.49
2040	115.65	107.59	92.83	90.48	58.17	39.63	93.67	109.27	111.11	114.75	116.85	119.73
2041	115.13	109.36	110.35	95.95	65.09	36.62	96.60	108.61	121.80	111.90	118.20	122.03
2042	124.72	115.06	106.16	84.11	61.11	38.73	104.28	115.00	124.37	122.07	120.82	127.58

SCHEDULE 201 (Continued)

WIND AND SOLAR INTEGRATION

TABLE 7		
Integration Costs		
Year	Wind	Solar
2017	0.85	0.85
2018	0.87	0.87
2019	0.88	0.88
2020	0.90	0.90
2021	0.92	0.92
2022	0.94	0.94
2023	0.96	0.96
2024	0.98	0.98
2025	1.00	1.00
2026	1.02	1.02
2027	1.04	1.04
2028	1.06	1.06
2029	1.08	1.08
2030	1.10	1.10
2031	1.12	1.12
2032	1.14	1.14
2033	1.17	1.17
2034	1.19	1.19
2035	1.21	1.21
2036	1.24	1.24
2037	1.26	1.26
2038	1.29	1.29
2039	1.31	1.31
2040	1.34	1.34
2041	1.37	1.37
2042	1.39	1.39

SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged $10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Continued)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.

b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

SCHEDULE 201 (Continued)

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term “Same Person(s)” or “Affiliated Person(s)” means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a “passive investor” whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a “passive investor” in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility’s safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility’s approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange (“ICE”) for the bilateral OTC market for energy at the Mid-C Physical for Average

SCHEDULE 201 (Continued)

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with “qualifying electricity,” as that term is defined in Oregon’s Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2024.

Definition of Resource Deficiency Period

This is the period from 2025.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2028.

Definition of Renewable Resource Deficiency Period

This is the period from 2029.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

> The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.
>
> The utility may respond to the complaint within ten days of service.
>
> The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.

2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller’s retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.

3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA’s termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

UM 1728 Application to Update Schedule 201 Qualifying Facility Information

Redlined Alternative Version
(*Effective date August 8, 2017*)

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

SCHEDULE 201 (Continued)

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

SCHEDULE 201 (Continued)

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

SCHEDULE 201 (Continued)

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed.

The Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any PPA year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for all other Net Output. (See the PPA for defined terms.)

1) **Standard Fixed Price Option**

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3c, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 18.59~~5~~%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be ~~5~~15.33%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind and Solar QFs (Tables 2a, ~~and~~ 2b, 3a, and 3b) include a reduction for the ~~wind~~ integration costs in Table 7. However, if the Wind or Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the ~~wind~~ integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b or 3a and 3b, for a net-zero effect.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

TABLE 1a
Avoided Costs
Standard Fixed Price Option for Base Load QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	57.28	57.40	57.49	56.78	56.75	56.67	56.77	56.85	56.97	57.07	57.81	57.92
2026	59.17	59.29	59.34	58.62	58.63	58.69	58.79	58.89	59.03	59.16	60.03	60.15
2027	61.01	61.13	61.04	60.30	60.44	60.19	60.29	60.39	60.52	61.27	59.92	60.04
2028	61.23	61.31	61.19	60.52	60.66	60.78	60.88	61.00	61.12	61.26	62.44	62.57
2029	64.03	64.16	64.28	63.58	63.76	64.88	65.00	65.13	65.28	65.40	66.74	66.88
2030	69.60	70.59	70.73	70.05	70.25	70.41	70.56	70.72	70.89	71.77	72.44	72.62
2031	74.30	74.48	74.10	73.00	73.15	73.04	73.18	73.34	73.51	73.69	74.85	75.02
2032	76.53	76.62	76.32	75.09	75.30	75.49	75.64	75.81	76.00	76.25	77.82	78.02
2033	80.07	80.28	80.02	78.86	79.09	79.29	79.46	79.64	79.85	80.26	81.68	81.90
2034	83.89	84.11	82.95	81.61	81.86	82.07	82.25	82.45	82.67	82.91	84.66	84.89
2035	86.73	86.97	85.83	84.45	84.70	84.37	84.55	84.75	84.99	85.49	86.97	87.42
2036	89.63	89.87	88.67	87.20	87.49	87.12	87.32	87.54	87.78	88.31	89.86	90.33
2037	92.90	93.16	91.91	90.37	90.65	90.28	90.48	90.71	90.95	91.53	93.15	93.66
2038	96.17	96.45	95.12	93.50	93.81	93.42	93.63	93.87	94.14	94.74	96.45	96.97
2039	99.60	99.87	98.49	96.79	97.11	96.69	96.92	97.17	97.45	98.09	99.87	100.43
2040	103.14	103.43	101.98	100.19	100.53	100.09	100.34	100.59	100.89	101.55	103.43	104.02
2041	106.88	107.19	105.65	103.77	104.11	103.66	103.92	104.18	104.50	105.20	107.17	107.79
2042	110.75	111.07	109.46	107.49	107.86	107.38	107.63	107.92	108.25	108.98	111.07	111.71

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 1b Avoided Costs Standard Fixed Price Option for Base Load QF Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	27.96	28.08	28.17	27.46	27.43	27.35	27.45	27.53	27.65	27.75	28.49	28.60
2026	29.26	29.39	29.43	28.71	28.72	28.79	28.89	28.99	29.12	29.25	30.12	30.24
2027	30.50	30.63	30.54	29.80	29.94	29.69	29.79	29.89	30.01	30.76	29.41	29.54
2028	30.11	30.19	30.08	29.41	29.55	29.66	29.77	29.88	30.01	30.15	31.33	31.45
2029	32.29	32.42	32.54	31.85	32.02	33.14	33.26	33.39	33.54	33.66	35.01	35.15
2030	37.23	38.22	38.36	37.68	37.88	38.04	38.19	38.35	38.52	39.40	40.07	40.25
2031	41.28	41.46	41.08	39.98	40.13	40.02	40.16	40.32	40.49	40.67	41.83	42.00
2032	43.06	43.15	42.85	41.62	41.84	42.02	42.17	42.35	42.54	42.79	44.35	44.55
2033	45.72	45.92	45.67	44.51	44.74	44.94	45.11	45.28	45.50	45.91	47.33	47.54
2034	48.74	48.96	47.80	46.46	46.71	46.91	47.10	47.29	47.51	47.76	49.51	49.74
2035	50.99	51.23	50.09	48.70	48.96	48.62	48.81	49.01	49.25	49.75	51.23	51.68
2036	53.29	53.53	52.33	50.86	51.15	50.78	50.98	51.20	51.45	51.97	53.52	53.99
2037	55.72	55.98	54.72	53.19	53.47	53.09	53.30	53.52	53.77	54.35	55.97	56.48
2038	58.24	58.52	57.19	55.57	55.88	55.49	55.70	55.94	56.21	56.81	58.52	59.04
2039	60.91	61.18	59.80	58.11	58.42	58.01	58.24	58.48	58.77	59.40	61.18	61.74
2040	63.68	63.97	62.52	60.73	61.07	60.63	60.88	61.12	61.43	62.09	63.97	64.55
2041	66.63	66.94	65.40	63.52	63.86	63.41	63.66	63.93	64.25	64.95	66.92	67.54
2042	69.70	70.02	68.40	66.43	66.80	66.33	66.57	66.86	67.20	67.93	70.02	70.66

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 2a
Avoided Costs
Standard Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	41.62	41.74	41.83	41.12	41.09	41.01	41.11	41.20	41.32	41.42	42.16	42.27
2026	43.20	43.32	43.37	42.65	42.66	42.72	42.82	42.92	43.06	43.19	44.06	44.18
2027	44.72	44.84	44.75	44.02	44.15	43.90	44.00	44.11	44.23	44.98	43.63	43.76
2028	44.62	44.70	44.58	43.91	44.05	44.16	44.27	44.38	44.51	44.65	45.83	45.96
2029	47.09	47.22	47.33	46.64	46.82	47.94	48.05	48.18	48.34	48.45	49.80	49.94
2030	52.32	53.31	53.45	52.77	52.97	53.13	53.28	53.44	53.61	54.49	55.16	55.34
2031	56.67	56.86	56.48	55.37	55.52	55.41	55.56	55.72	55.89	56.06	57.23	57.40
2032	58.66	58.75	58.45	57.22	57.43	57.62	57.77	57.95	58.13	58.38	59.95	60.15
2033	61.73	61.93	61.68	60.52	60.75	60.95	61.12	61.30	61.51	61.92	63.34	63.55
2034	65.13	65.35	64.19	62.85	63.10	63.31	63.49	63.68	63.91	64.15	65.90	66.13
2035	67.65	67.89	66.75	65.37	65.62	65.29	65.48	65.68	65.91	66.42	67.89	68.34
2036	70.22	70.47	69.26	67.80	68.08	67.72	67.92	68.14	68.38	68.91	70.45	70.93
2037	73.05	73.32	72.06	70.53	70.80	70.43	70.64	70.86	71.11	71.69	73.30	73.81
2038	75.92	76.20	74.87	73.25	73.56	73.17	73.38	73.62	73.89	74.49	76.20	76.72
2039	78.95	79.22	77.84	76.15	76.46	76.04	76.27	76.52	76.81	77.44	79.22	79.78
2040	82.07	82.36	80.91	79.13	79.46	79.02	79.27	79.52	79.83	80.49	82.36	82.95
2041	85.39	85.70	84.16	82.28	82.62	82.17	82.43	82.70	83.01	83.71	85.69	86.30
2042	88.84	89.16	87.55	85.58	85.94	85.47	85.72	86.01	86.34	87.07	89.16	89.80

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 2b
Avoided Costs
Standard Fixed Price Option for Wind QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	26.96	27.08	27.17	26.46	26.43	26.35	26.45	26.53	26.65	26.75	27.49	27.60
2026	28.24	28.37	28.41	27.69	27.70	27.77	27.87	27.97	28.10	28.23	29.10	29.22
2027	29.46	29.59	29.50	28.76	28.90	28.65	28.75	28.85	28.97	29.72	28.37	28.50
2028	29.05	29.13	29.02	28.35	28.49	28.60	28.71	28.82	28.95	29.09	30.27	30.39
2029	31.21	31.34	31.46	30.77	30.94	32.06	32.18	32.31	32.46	32.58	33.93	34.07
2030	36.13	37.12	37.26	36.58	36.78	36.94	37.09	37.25	37.42	38.30	38.97	39.15
2031	40.16	40.34	39.96	38.86	39.01	38.90	39.04	39.20	39.37	39.55	40.71	40.88
2032	41.92	42.01	41.71	40.48	40.70	40.88	41.03	41.21	41.40	41.65	43.21	43.41
2033	44.55	44.75	44.50	43.34	43.57	43.77	43.94	44.11	44.33	44.74	46.16	46.37
2034	47.55	47.77	46.61	45.27	45.52	45.72	45.91	46.10	46.32	46.57	48.32	48.55
2035	49.78	50.02	48.88	47.49	47.75	47.41	47.60	47.80	48.04	48.54	50.02	50.47
2036	52.05	52.29	51.09	49.62	49.91	49.54	49.74	49.96	50.21	50.73	52.28	52.75
2037	54.46	54.72	53.46	51.93	52.21	51.83	52.04	52.26	52.51	53.09	54.71	55.22
2038	56.95	57.23	55.90	54.28	54.59	54.20	54.41	54.65	54.92	55.52	57.23	57.75
2039	59.60	59.87	58.49	56.80	57.11	56.70	56.93	57.17	57.46	58.09	59.87	60.43
2040	62.34	62.63	61.18	59.39	59.73	59.29	59.54	59.78	60.09	60.75	62.63	63.21
2041	65.26	65.57	64.03	62.15	62.49	62.04	62.29	62.56	62.88	63.58	65.55	66.17
2042	68.31	68.63	67.01	65.04	65.41	64.94	65.18	65.47	65.81	66.54	68.63	69.27

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3a												
Avoided Costs Standard Fixed Price Option for Solar QF												
On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	38.93	39.05	39.13	38.43	38.39	38.32	38.42	38.50	38.62	38.72	39.46	39.57
2026	40.45	40.57	40.62	39.90	39.91	39.97	40.07	40.17	40.31	40.44	41.31	41.43
2027	41.91	42.04	41.95	41.21	41.35	41.10	41.20	41.30	41.43	42.17	40.83	40.95
2028	41.75	41.84	41.72	41.05	41.19	41.30	41.41	41.52	41.65	41.79	42.97	43.10
2029	44.17	44.30	44.42	43.72	43.90	45.02	45.14	45.27	45.42	45.54	46.88	47.02
2030	49.34	50.33	50.48	49.79	49.99	50.15	50.31	50.46	50.63	51.51	52.18	52.36
2031	53.64	53.82	53.44	52.34	52.49	52.37	52.52	52.68	52.85	53.02	54.19	54.36
2032	55.58	55.67	55.37	54.14	54.36	54.54	54.69	54.87	55.06	55.31	56.87	57.07
2033	58.57	58.78	58.52	57.36	57.59	57.79	57.96	58.14	58.35	58.76	60.18	60.40
2034	61.90	62.12	60.96	59.62	59.87	60.07	60.26	60.45	60.67	60.92	62.66	62.90
2035	64.37	64.61	63.46	62.08	62.34	62.00	62.19	62.39	62.63	63.13	64.61	65.06
2036	66.88	67.12	65.92	64.46	64.74	64.38	64.58	64.80	65.04	65.57	67.11	67.58
2037	69.64	69.90	68.64	67.11	67.38	67.01	67.22	67.44	67.69	68.27	69.88	70.40
2038	72.43	72.71	71.39	69.77	70.08	69.68	69.89	70.13	70.40	71.01	72.71	73.23
2039	75.39	75.66	74.28	72.59	72.90	72.49	72.72	72.96	73.25	73.88	75.66	76.22
2040	78.44	78.74	77.28	75.50	75.83	75.39	75.64	75.89	76.20	76.86	78.74	79.32
2041	81.69	82.00	80.46	78.58	78.92	78.47	78.72	78.99	79.31	80.01	81.98	82.60
2042	85.07	85.39	83.77	81.80	82.17	81.70	81.94	82.23	82.57	83.30	85.39	86.03

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3b
Avoided Costs
Standard Fixed Price Option for Solar QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	26.96	27.08	27.17	26.46	26.43	26.35	26.45	26.53	26.65	26.75	27.49	27.60
2026	28.24	28.37	28.41	27.69	27.70	27.77	27.87	27.97	28.10	28.23	29.10	29.22
2027	29.46	29.59	29.50	28.76	28.90	28.65	28.75	28.85	28.97	29.72	28.37	28.50
2028	29.05	29.13	29.02	28.35	28.49	28.60	28.71	28.82	28.95	29.09	30.27	30.39
2029	31.21	31.34	31.46	30.77	30.94	32.06	32.18	32.31	32.46	32.58	33.93	34.07
2030	36.13	37.12	37.26	36.58	36.78	36.94	37.09	37.25	37.42	38.30	38.97	39.15
2031	40.16	40.34	39.96	38.86	39.01	38.90	39.04	39.20	39.37	39.55	40.71	40.88
2032	41.92	42.01	41.71	40.48	40.70	40.88	41.03	41.21	41.40	41.65	43.21	43.41
2033	44.55	44.75	44.50	43.34	43.57	43.77	43.94	44.11	44.33	44.74	46.16	46.37
2034	47.55	47.77	46.61	45.27	45.52	45.72	45.91	46.10	46.32	46.57	48.32	48.55
2035	49.78	50.02	48.88	47.49	47.75	47.41	47.60	47.80	48.04	48.54	50.02	50.47
2036	52.05	52.29	51.09	49.62	49.91	49.54	49.74	49.96	50.21	50.73	52.28	52.75
2037	54.46	54.72	53.46	51.93	52.21	51.83	52.04	52.26	52.51	53.09	54.71	55.22
2038	56.95	57.23	55.90	54.28	54.59	54.20	54.41	54.65	54.92	55.52	57.23	57.75
2039	59.60	59.87	58.49	56.80	57.11	56.70	56.93	57.17	57.46	58.09	59.87	60.43
2040	62.34	62.63	61.18	59.39	59.73	59.29	59.54	59.78	60.09	60.75	62.63	63.21
2041	65.26	65.57	64.03	62.15	62.49	62.04	62.29	62.56	62.88	63.58	65.55	66.17
2042	68.31	68.63	67.01	65.04	65.41	64.94	65.18	65.47	65.81	66.54	68.63	69.27

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of ~~5~~18.59%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be ~~5~~15.33%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind and solar QFs (Tables 5a,~~ and~~ 5b, 6a, and 6b) include a reduction for the ~~wind ~~integration costs in Table 7, which cancels out ~~wind ~~integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind or Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the ~~wind ~~integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b or 6a and 6b.

Sellers with PPAs exceeding 15 years will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

Renewable Fixed Price Option (Continued)

TABLE 4a
Renewable Avoided Costs
Renewable Fixed Price Option for Base Load QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	36.28	36.45	32.07	27.15	25.16	20.76	31.18	33.59	36.96	36.50	36.17	38.88
2026	38.02	38.42	34.69	28.61	23.72	19.90	33.16	36.49	39.07	39.98	39.93	41.34
2027	40.65	40.65	35.03	29.55	25.62	19.81	33.68	38.68	40.37	41.18	39.95	42.49
2028	41.59	39.62	35.61	29.31	24.13	18.69	35.04	39.47	41.56	42.04	42.77	45.50
2029	130.46	122.16	114.93	99.44	91.28	66.74	111.72	123.40	130.72	125.77	127.43	137.59
2030	131.08	128.53	117.83	98.71	84.69	62.99	114.81	124.72	133.57	132.78	130.81	140.19
2031	131.64	130.86	120.44	98.71	91.59	75.33	113.41	127.20	134.67	132.63	129.43	138.99
2032	134.62	132.28	119.05	100.89	89.34	66.65	119.99	136.17	137.32	134.74	138.45	144.33
2033	137.25	136.91	119.61	101.75	86.72	86.02	122.63	133.68	138.82	137.65	139.72	144.28
2034	142.85	142.41	123.71	103.53	88.59	73.28	127.14	137.57	142.77	143.43	144.85	150.81
2035	148.82	142.53	126.90	103.23	91.63	67.83	123.14	139.46	145.86	143.75	142.41	153.08
2036	149.95	144.47	128.97	105.99	82.91	55.60	131.13	142.04	150.30	148.99	147.58	158.25
2037	150.31	149.85	132.81	104.38	91.13	77.19	129.68	144.87	152.33	149.48	149.48	159.99
2038	153.59	155.69	131.34	104.62	84.94	70.00	139.81	155.20	158.10	155.40	156.18	165.33
2039	155.36	153.84	130.69	105.47	94.56	80.72	140.16	151.56	157.69	151.05	155.29	162.46
2040	157.59	155.79	132.79	114.89	87.55	75.00	145.49	156.16	163.50	158.77	161.06	169.93
2041	161.95	158.31	139.08	119.78	109.77	63.50	144.74	159.21	165.49	156.15	156.63	168.47
2042	164.72	162.40	143.32	120.89	93.22	64.66	149.09	163.83	169.34	163.16	161.00	175.92

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 4b												
Renewable Avoided Costs Renewable Fixed Price Option for Base Load QF												
Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	33.70	32.17	29.76	25.01	21.99	19.00	26.39	30.90	33.57	33.77	33.61	34.83
2026	35.44	35.59	31.64	27.21	22.20	15.26	28.97	33.61	36.07	35.46	35.51	37.70
2027	36.66	35.71	32.22	27.60	23.64	18.12	29.40	34.72	37.35	37.55	36.31	38.40
2028	38.09	37.21	33.20	27.82	23.65	17.34	31.56	36.38	38.22	38.77	39.08	40.92
2029	87.39	83.14	79.75	60.89	56.60	30.37	68.86	84.70	91.46	89.10	90.05	95.00
2030	90.66	87.81	81.88	62.46	52.25	31.31	75.55	87.01	93.96	93.87	94.23	96.33
2031	94.53	91.33	79.90	66.32	59.86	41.01	74.22	87.92	95.40	93.03	92.05	96.31
2032	95.12	90.63	85.26	64.49	46.09	33.03	81.76	88.62	98.19	95.17	97.79	103.88
2033	96.72	93.73	84.37	65.02	55.14	44.09	81.80	90.25	98.91	96.03	97.55	104.35
2034	100.64	96.93	84.22	63.90	50.21	33.88	82.22	94.26	101.29	101.38	105.38	107.75
2035	103.38	100.59	93.20	71.90	61.31	46.52	81.06	99.14	104.45	99.35	103.56	106.09
2036	111.16	105.72	94.24	72.48	61.23	31.45	82.90	100.58	110.79	104.85	108.44	114.13
2037	110.15	107.49	96.32	79.57	59.61	38.00	86.10	101.85	110.09	103.94	105.91	113.12
2038	113.74	110.37	97.67	79.06	51.82	34.44	88.62	103.26	110.27	107.20	111.44	117.93
2039	110.16	108.78	96.61	84.94	62.94	60.33	93.55	103.97	110.69	110.48	115.32	122.80
2040	116.99	108.93	94.17	91.82	59.51	40.97	95.01	110.61	112.45	116.09	118.19	121.07
2041	116.50	110.73	111.72	97.32	66.46	37.99	97.97	109.98	123.17	113.27	119.57	123.40
2042	126.11	116.45	107.55	85.50	62.50	40.12	105.67	116.39	125.76	123.46	122.21	128.97

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 5a
Renewable Avoided Costs
Renewable Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	35.28	35.45	31.07	26.15	24.16	19.76	30.18	32.59	35.96	35.50	35.17	37.88
2026	37.00	37.40	33.67	27.59	22.70	18.88	32.14	35.47	38.05	38.96	38.91	40.32
2027	39.61	39.61	33.99	28.51	24.58	18.77	32.64	37.64	39.33	40.14	38.91	41.45
2028	40.53	38.56	34.55	28.25	23.07	17.63	33.98	38.41	40.50	40.98	41.71	44.44
2029	113.52	105.21	97.99	82.50	74.34	49.80	94.77	106.45	113.77	108.83	110.48	120.64
2030	113.80	111.24	100.54	81.43	67.41	45.70	97.52	107.44	116.29	115.50	113.53	122.91
2031	114.02	113.23	102.81	81.08	73.97	57.71	95.79	109.57	117.04	115.01	111.80	121.36
2032	116.76	114.41	101.18	83.02	71.47	48.78	102.12	118.30	119.45	116.88	120.58	126.46
2033	118.91	118.57	101.27	83.40	68.38	67.68	104.29	115.34	120.47	119.31	121.38	125.94
2034	124.09	123.65	104.95	84.77	69.82	54.52	108.37	118.81	124.01	124.67	126.09	132.05
2035	129.75	123.46	107.82	84.16	72.56	48.75	104.07	120.39	126.78	124.67	123.33	134.01
2036	130.55	125.06	109.57	86.58	63.51	36.20	111.72	122.63	130.90	129.59	128.17	138.84
2037	130.46	130.00	112.97	84.54	71.28	57.35	109.83	125.02	132.49	129.63	129.63	140.14
2038	133.34	135.44	111.09	84.37	64.69	49.75	119.56	134.95	137.85	135.16	135.93	145.08
2039	134.72	133.19	110.04	84.82	73.91	60.08	119.52	130.91	137.04	130.40	134.64	141.81
2040	136.52	134.72	111.73	93.82	66.49	53.93	124.43	135.10	142.44	137.70	140.00	148.87
2041	140.47	136.82	117.59	98.30	88.28	42.01	123.25	137.72	144.00	134.66	135.14	146.98
2042	142.81	140.48	121.41	98.97	71.31	42.74	127.18	141.92	147.43	141.25	139.09	154.01

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 5b												
Renewable Avoided Costs Renewable Fixed Price Option for Wind QF												
Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	32.70	31.17	28.76	24.01	20.99	18.00	25.39	29.90	32.57	32.77	32.61	33.83
2026	34.42	34.57	30.62	26.19	21.18	14.24	27.95	32.59	35.05	34.44	34.49	36.68
2027	35.62	34.67	31.18	26.56	22.60	17.08	28.36	33.68	36.31	36.51	35.27	37.36
2028	37.03	36.15	32.14	26.76	22.59	16.28	30.50	35.32	37.16	37.71	38.02	39.86
2029	86.31	82.06	78.67	59.81	55.52	29.29	67.78	83.62	90.38	88.02	88.97	93.92
2030	89.56	86.71	80.78	61.36	51.15	30.21	74.45	85.91	92.86	92.77	93.13	95.23
2031	93.41	90.21	78.78	65.20	58.74	39.89	73.10	86.80	94.28	91.91	90.93	95.19
2032	93.98	89.49	84.12	63.35	44.95	31.89	80.62	87.48	97.05	94.03	96.65	102.74
2033	95.55	92.56	83.20	63.85	53.97	42.92	80.63	89.08	97.74	94.86	96.38	103.18
2034	99.45	95.74	83.03	62.71	49.02	32.69	81.03	93.07	100.10	100.19	104.19	106.56
2035	102.17	99.38	91.99	70.69	60.10	45.31	79.85	97.93	103.24	98.14	102.35	104.88
2036	109.92	104.48	93.00	71.24	59.99	30.21	81.66	99.34	109.55	103.61	107.20	112.89
2037	108.89	106.23	95.06	78.31	58.35	36.74	84.84	100.59	108.83	102.68	104.65	111.86
2038	112.45	109.08	96.38	77.77	50.53	33.15	87.33	101.97	108.98	105.91	110.15	116.64
2039	108.85	107.47	95.30	83.63	61.63	59.02	92.24	102.66	109.38	109.17	114.01	121.49
2040	115.65	107.59	92.83	90.48	58.17	39.63	93.67	109.27	111.11	114.75	116.85	119.73
2041	115.13	109.36	110.35	95.95	65.09	36.62	96.60	108.61	121.80	111.90	118.20	122.03
2042	124.72	115.06	106.16	84.11	61.11	38.73	104.28	115.00	124.37	122.07	120.82	127.58

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6a
Renewable Avoided Costs
Renewable Fixed Price Option for Solar QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								33.96	28.61	26.06	26.57	32.68
2018	31.14	28.59	24.51	20.27	19.75	20.27	29.14	32.55	30.19	24.76	26.80	31.40
2019	30.30	28.61	23.01	18.37	17.74	18.65	29.26	33.59	30.55	26.03	28.05	33.46
2020	31.94	30.16	24.25	19.36	18.69	19.66	30.84	35.40	32.19	27.43	29.56	35.26
2021	33.68	31.80	25.54	20.36	19.66	20.69	32.52	37.35	33.95	28.90	31.17	37.21
2022	35.53	33.54	26.94	21.48	20.74	21.82	34.31	39.40	35.81	30.50	32.87	39.25
2023	31.59	31.52	27.55	24.15	22.18	20.89	27.33	30.07	32.42	32.91	33.05	35.11
2024	35.18	33.49	30.86	25.06	22.30	15.29	28.04	31.74	34.75	34.95	35.85	38.21
2025	35.28	35.45	31.07	26.15	24.16	19.76	30.18	32.59	35.96	35.50	35.17	37.88
2026	37.00	37.40	33.67	27.59	22.70	18.88	32.14	35.47	38.05	38.96	38.91	40.32
2027	39.61	39.61	33.99	28.51	24.58	18.77	32.64	37.64	39.33	40.14	38.91	41.45
2028	40.53	38.56	34.55	28.25	23.07	17.63	33.98	38.41	40.50	40.98	41.71	44.44
2029	110.60	102.29	95.07	79.58	71.42	46.88	91.85	103.54	110.85	105.91	107.56	117.72
2030	110.82	108.27	97.57	78.45	64.43	42.73	94.55	104.46	113.31	112.52	110.55	119.93
2031	110.98	110.19	99.78	78.05	70.93	54.67	92.75	106.54	114.01	111.97	108.77	118.33
2032	113.68	111.33	98.10	79.95	68.40	45.70	99.05	115.22	116.37	113.80	117.51	123.38
2033	115.75	115.41	98.11	80.25	65.22	64.52	101.13	112.18	117.32	116.15	118.22	122.78
2034	120.86	120.42	101.71	81.54	66.59	51.28	105.14	115.58	120.78	121.43	122.86	128.82
2035	126.46	120.17	104.54	80.87	69.27	45.47	100.78	117.10	123.50	121.38	120.05	130.72
2036	127.20	121.72	106.23	83.24	60.16	32.86	108.38	119.29	127.56	126.25	124.83	135.50
2037	127.04	126.58	109.55	81.12	67.86	53.93	106.42	121.60	129.07	126.21	126.21	136.72
2038	129.86	131.95	107.60	80.88	61.20	46.26	116.08	131.46	134.36	131.67	132.45	141.59
2039	131.16	129.64	106.49	81.27	70.35	56.52	115.96	127.36	133.49	126.84	131.09	138.25
2040	132.90	131.10	108.10	90.19	62.86	50.30	120.80	131.47	138.81	134.08	136.37	145.24
2041	136.76	133.12	113.89	94.59	84.58	38.31	119.55	134.02	140.30	130.96	131.44	143.28
2042	139.03	136.71	117.63	95.20	67.53	38.97	123.41	138.15	143.66	137.47	135.31	150.23

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6b
Renewable Avoided Costs
Renewable Fixed Price Option for Solar QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								23.66	23.87	23.00	23.26	26.57
2018	26.55	24.00	19.93	14.31	11.25	10.01	18.71	23.37	23.82	21.64	22.82	26.54
2019	23.54	23.73	18.41	12.58	9.54	9.19	18.27	24.18	24.65	22.45	23.99	28.50
2020	25.45	25.65	19.90	13.58	10.29	9.90	19.74	26.13	26.64	24.27	25.94	30.82
2021	27.26	27.48	21.28	14.47	10.93	10.52	21.11	28.00	28.55	25.98	27.79	33.05
2022	29.17	29.40	22.77	15.48	11.67	11.24	22.59	29.97	30.56	27.81	29.74	35.38
2023	29.49	28.50	26.17	21.82	20.26	18.32	24.28	27.26	29.95	30.17	30.59	31.81
2024	31.51	28.97	28.36	23.85	20.57	12.83	24.46	28.63	31.08	31.29	33.43	34.82
2025	32.70	31.17	28.76	24.01	20.99	18.00	25.39	29.90	32.57	32.77	32.61	33.83
2026	34.42	34.57	30.62	26.19	21.18	14.24	27.95	32.59	35.05	34.44	34.49	36.68
2027	35.62	34.67	31.18	26.56	22.60	17.08	28.36	33.68	36.31	36.51	35.27	37.36
2028	37.03	36.15	32.14	26.76	22.59	16.28	30.50	35.32	37.16	37.71	38.02	39.86
2029	86.31	82.06	78.67	59.81	55.52	29.29	67.78	83.62	90.38	88.02	88.97	93.92
2030	89.56	86.71	80.78	61.36	51.15	30.21	74.45	85.91	92.86	92.77	93.13	95.23
2031	93.41	90.21	78.78	65.20	58.74	39.89	73.10	86.80	94.28	91.91	90.93	95.19
2032	93.98	89.49	84.12	63.35	44.95	31.89	80.62	87.48	97.05	94.03	96.65	102.74
2033	95.55	92.56	83.20	63.85	53.97	42.92	80.63	89.08	97.74	94.86	96.38	103.18
2034	99.45	95.74	83.03	62.71	49.02	32.69	81.03	93.07	100.10	100.19	104.19	106.56
2035	102.17	99.38	91.99	70.69	60.10	45.31	79.85	97.93	103.24	98.14	102.35	104.88
2036	109.92	104.48	93.00	71.24	59.99	30.21	81.66	99.34	109.55	103.61	107.20	112.89
2037	108.89	106.23	95.06	78.31	58.35	36.74	84.84	100.59	108.83	102.68	104.65	111.86
2038	112.45	109.08	96.38	77.77	50.53	33.15	87.33	101.97	108.98	105.91	110.15	116.64
2039	108.85	107.47	95.30	83.63	61.63	59.02	92.24	102.66	109.38	109.17	114.01	121.49
2040	115.65	107.59	92.83	90.48	58.17	39.63	93.67	109.27	111.11	114.75	116.85	119.73
2041	115.13	109.36	110.35	95.95	65.09	36.62	96.60	108.61	121.80	111.90	118.20	122.03
2042	124.72	115.06	106.16	84.11	61.11	38.73	104.28	115.00	124.37	122.07	120.82	127.58

SCHEDULE 201 (Continued)

WIND AND SOLAR INTEGRATION

TABLE 7		
Integration Costs		
Year	Wind	Solar
2017	0.85	0.85
2018	0.87	0.87
2019	0.88	0.88
2020	0.90	0.90
2021	0.92	0.92
2022	0.94	0.94
2023	0.96	0.96
2024	0.98	0.98
2025	1.00	1.00
2026	1.02	1.02
2027	1.04	1.04
2028	1.06	1.06
2029	1.08	1.08
2030	1.10	1.10
2031	1.12	1.12
2032	1.14	1.14
2033	1.17	1.17
2034	1.19	1.19
2035	1.21	1.21
2036	1.24	1.24
2037	1.26	1.26
2038	1.29	1.29
2039	1.31	1.31
2040	1.34	1.34
2041	1.37	1.37
2042	1.39	1.39

SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged $10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Continued)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA

A QF will be eligible to receive pricing under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 10 MW. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.

b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

SCHEDULE 201 (Continued)

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE PRICING UNDER THE STANDARD PPA (Continued)

Definition of Person(s) or Affiliated Person(s)

As used above, the term "Same Person(s)" or "Affiliated Person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a "passive investor" in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard PPA.

OTHER DEFINITIONS

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the Day Ahead Intercontinental Exchange ("ICE") for the bilateral OTC market for energy at the Mid-C Physical for Average

SCHEDULE 201 (Continued)

OTHER DEFINITIONS (Continued)

On-Peak Power and Average Off-Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through ~~2020~~2024.

Definition of Resource Deficiency Period

This is the period from 202~~1 through 2034~~5.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through ~~2019~~2028.

Definition of Renewable Resource Deficiency Period

This is the period from 202~~0 through 2034~~9.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

> The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.
>
> The utility may respond to the complaint within ten days of service.
>
> The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.

2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.

3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

UM 1728 Application to Update Schedule 201 Qualifying Facility Information

Attachment A
Description of Standard Avoided Costs

PORTLAND GENERAL ELECTRIC COMPANY
STANDARD AVOIDED COST STUDY
2016 IRP UPDATE
August 18, 2017

Introduction

This avoided cost update is made consistent with PGE's 2016 Integrated Resource Plan (IRP). The Commission directs electric utilities to make an avoided cost filing within 30 days of IRP acknowledgement.

Integrated Resource Plan

The Commission partially acknowledged PGE's 2016 IRP on August 8, 2017. The 2016 IRP forms the basis of most of the inputs in this avoided cost study.

Resource Timing

The resource deficiency period for nonrenewable resources starts in 2025, consistent with the Commission's August 8, 2017 acknowledgement decision.

Avoided Cost Estimates

Tables 1 and 2 (following) summarize the results for PGE's fixed price option. Tables 1 and 2 are estimates of monthly on- and off-peak avoided costs for energy and capacity for 20 years beginning in 2017. The resource sufficiency period prices (expressed in $/MWh or mills/kWh) for the years 2017 through 2020, are based on forward electricity curves, and represent capacity and energy avoided costs.

On-peak prices beginning 2021 are represented by capacity and energy costs, while off-peak prices are represented by energy costs only. The on-peak price includes the following costs of a CCCT: fuel, variable O&M, capacity, and other fixed costs. The off-peak price includes: fuel, variable O&M, and other fixed costs. The "other fixed costs" represent the energy portion of the fixed costs of a CCCT. Other fixed costs are calculated by taking the fixed costs of a CCCT minus the real levelized capital carrying cost and fixed O&M of an SCCT. The result (other fixed costs) represents the energy portion of the fixed costs of a CCCT. On-peak periods are from 6 a.m. through 10 p.m. Mondays through Saturdays. The off-peak hours are from 10 p.m. until 6 a.m. Mondays through Saturdays and all twenty-four hours on Sunday. Table 3 provides flat monthly avoided costs, and Tables 4 and 5 show the on- and off-peak resource sufficiency rates.

PGE's 2017 AVOIDED COST STUDY
WORKPAPERS – Page 2

Resource Sufficiency Period Pricing

Resource sufficiency period prices are based on forward Mid-Columbia electricity trading curves delivered to PGE's system. The forward trading curves are dated July 13, 2017.

Gas Price Projections

The basis for the gas prices used in this study is described on Page 79 of PGE's 2016 IRP. The forecast is from June 2017.

In order to simplify market-based pricing, the estimate of gas transportation costs is fixed. The heat rate of a CCCT is then applied to the estimated transportation costs for both the AECO and Sumas trading hubs. This gas transportation estimate is added to the fixed costs and variable O&M costs to calculate Table 12.

Renewable Capacity Contribution

To translate the renewable capacity contribution into prices for standard avoided costs consistent with Order No. 16-174, several inputs are necessary. First, the capacity contribution percentages of both wind and solar resources are necessary. The capacity contribution percentages are provided in PGE's 2016 IRP. The capacity contribution for wind is 18.59% and the capacity contribution for solar is 15.33%. Two additional inputs are necessary:

(1) The on-peak capacity factor of the wind resource of 35.24% is calculated from the wind resource used to derive the capacity contribution for wind.
(2) The on-peak capacity factor of the solar resource of 35.61% is calculated from the solar resource used to derive the capacity contribution for solar.

The translation of renewable capacity contribution into avoided cost prices is performed in two simple steps.

Step one: remove capacity value from all hours for the proxy gas resource.

Step two: add capacity in the on-peak hours for wind and solar QFs separately.

CO2 (Carbon) Regulation

The Company, as directed in Order No. 08-339 is continues to evaluate expected regulatory compliance for CO2 in the context of resource planning. However, because no carbon regulation has yet been legislated, this filing includes no assumptions relative to cost effects of CO_2 regulation. This practice is consistent with PGE's avoided costs since Commission Order No. 05-584.

Avoided Cost Components

Tables 6 through 12 in the work papers show the capacity, fixed, variable, and gas forecast avoided cost components. The on- and off-peak SCCT-related capacity component costs are shown in Tables 6 and 7. Table 7 is blank since no capacity value is calculated for the off-peak period. The capacity values are applicable to on-peak hours. Table 8 contains the energy portion of a CCCT, calculated using fixed costs of a CCCT minus the real levelized capital carrying cost and fixed O&M of an SCCT. Table 9 shows the variable O&M associated with the CCCT and Table 10 shows the projected fuel costs. Tables 6, 8, 9 and 10 can be summed to equal the total on-peak avoided costs in Table 1. Tables 7, 8, 9 and 10 can be summed to equal the total off-peak avoided costs in Table 2.

Portland General Electric
Avoided Cost Study
Total Projected On-Peak Avoided Costs

Table 1

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2017	43.57	30.73	9.33	10.60	15.19	22.58	31.49	34.81	29.46	26.91	27.42	33.53	26.26
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27	27.48
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34	27.36
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16	28.83
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13	30.33
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19	31.98
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07	30.00
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19	31.48
2025	57.28	57.40	57.49	56.78	56.75	56.67	56.77	56.85	56.97	57.07	57.81	57.92	57.14
2026	59.17	59.29	59.34	58.62	58.63	58.69	58.79	58.89	59.03	59.16	60.03	60.15	59.15
2027	61.01	61.13	61.04	60.30	60.44	60.19	60.29	60.39	60.52	61.27	59.92	60.04	60.54
2028	61.23	61.31	61.19	60.52	60.66	60.78	60.88	61.00	61.12	61.26	62.44	62.57	61.25
2029	64.03	64.16	64.28	63.58	63.76	64.88	65.00	65.13	65.28	65.40	66.74	66.88	64.93
2030	69.60	70.59	70.73	70.05	70.25	70.41	70.56	70.72	70.89	71.77	72.44	72.62	70.88
2031	74.30	74.48	74.10	73.00	73.15	73.04	73.18	73.34	73.51	73.69	74.85	75.02	73.80
2032	76.53	76.62	76.32	75.09	75.30	75.49	75.64	75.81	76.00	76.25	77.82	78.02	76.24
2033	80.07	80.28	80.02	78.86	79.09	79.29	79.46	79.64	79.85	80.26	81.68	81.90	80.04
2034	83.89	84.11	82.95	81.61	81.86	82.07	82.25	82.45	82.67	82.91	84.66	84.89	83.02
2035	86.73	86.97	85.83	84.45	84.70	84.37	84.55	84.75	84.99	85.49	86.97	87.42	85.60
2036	89.63	89.87	88.67	87.20	87.49	87.12	87.32	87.54	87.78	88.31	89.86	90.33	88.43
2037	92.90	93.16	91.91	90.37	90.65	90.28	90.48	90.71	90.95	91.53	93.15	93.66	91.64
2038	96.17	96.45	95.12	93.50	93.81	93.42	93.63	93.87	94.14	94.74	96.45	96.97	94.85
2039	99.60	99.87	98.49	96.79	97.11	96.69	96.92	97.17	97.45	98.09	99.87	100.43	98.20
2040	103.14	103.43	101.98	100.19	100.53	100.09	100.34	100.59	100.89	101.55	103.43	104.02	101.68
2041	106.88	107.19	105.65	103.77	104.11	103.66	103.92	104.18	104.50	105.20	107.17	107.79	105.32
2042	110.75	111.07	109.46	107.49	107.86	107.38	107.63	107.92	108.25	108.98	111.07	111.71	109.12

Portland General Electric
Avoided Cost Study
Total Projected Off-Peak Avoided Costs

Table 2

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2017	31.49	25.89	2.71	5.21	3.22	6.53	19.27	24.51	24.72	23.85	24.11	27.42	18.29
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41	21.12
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38	20.80
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72	22.41
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97	23.95
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32	25.55
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77	27.53
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80	28.46
2025	27.96	28.08	28.17	27.46	27.43	27.35	27.45	27.53	27.65	27.75	28.49	28.60	27.83
2026	29.26	29.39	29.43	28.71	28.72	28.79	28.89	28.99	29.12	29.25	30.12	30.24	29.24
2027	30.50	30.63	30.54	29.80	29.94	29.69	29.79	29.89	30.01	30.76	29.41	29.54	30.04
2028	30.11	30.19	30.08	29.41	29.55	29.66	29.77	29.88	30.01	30.15	31.33	31.45	30.13
2029	32.29	32.42	32.54	31.85	32.02	33.14	33.26	33.39	33.54	33.66	35.01	35.15	33.20
2030	37.23	38.22	38.36	37.68	37.88	38.04	38.19	38.35	38.52	39.40	40.07	40.25	38.52
2031	41.28	41.46	41.08	39.98	40.13	40.02	40.16	40.32	40.49	40.67	41.83	42.00	40.78
2032	43.06	43.15	42.85	41.62	41.84	42.02	42.17	42.35	42.54	42.79	44.35	44.55	42.77
2033	45.72	45.92	45.67	44.51	44.74	44.94	45.11	45.28	45.50	45.91	47.33	47.54	45.67
2034	48.74	48.96	47.80	46.46	46.71	46.91	47.10	47.29	47.51	47.76	49.51	49.74	47.87
2035	50.99	51.23	50.09	48.70	48.96	48.62	48.81	49.01	49.25	49.75	51.23	51.68	49.85
2036	53.29	53.53	52.33	50.86	51.15	50.78	50.98	51.20	51.45	51.97	53.52	53.99	52.08
2037	55.72	55.98	54.72	53.19	53.47	53.09	53.30	53.52	53.77	54.35	55.97	56.48	54.46
2038	58.24	58.52	57.19	55.57	55.88	55.49	55.70	55.94	56.21	56.81	58.52	59.04	56.92
2039	60.91	61.18	59.80	58.11	58.42	58.01	58.24	58.48	58.77	59.40	61.18	61.74	59.51
2040	63.68	63.97	62.52	60.73	61.07	60.63	60.88	61.12	61.43	62.09	63.97	64.55	62.22
2041	66.63	66.94	65.40	63.52	63.86	63.41	63.66	63.93	64.25	64.95	66.92	67.54	65.08
2042	69.70	70.02	68.40	66.43	66.80	66.33	66.57	66.86	67.20	67.93	70.02	70.66	68.07

Portland General Electric
Avoided Cost Study
Total Projected Average Avoided Costs

Table 3 Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2017	38.25	28.65	6.55	8.21	10.17	15.80	26.10	30.49	27.45	25.56	26.02	30.84	22.83
2018	30.08	27.49	23.46	18.50	17.06	16.81	25.41	29.57	28.23	24.32	25.99	30.13	24.76
2019	28.34	27.40	21.86	16.81	15.18	15.33	25.53	30.52	28.80	25.41	27.22	32.15	24.55
2020	30.12	29.14	23.23	17.82	15.89	16.44	27.09	32.22	30.75	27.00	28.85	34.30	26.08
2021	31.77	30.87	24.67	18.80	16.73	17.32	28.66	34.15	32.59	28.53	30.66	36.39	27.60
2022	33.67	32.71	26.13	19.88	17.69	18.29	30.08	36.38	34.53	30.25	32.49	38.56	29.23
2023	31.63	31.19	27.93	24.08	22.34	20.76	26.95	29.85	32.34	32.66	32.97	34.62	28.94
2024	34.62	32.55	30.74	25.53	22.56	15.18	27.52	31.42	34.10	34.40	35.81	37.70	30.19
2025	44.98	44.83	44.56	44.40	44.45	43.64	44.47	43.93	44.59	44.78	44.78	45.63	44.59
2026	46.63	46.48	46.15	45.99	45.44	46.07	46.25	45.71	46.40	46.62	46.74	47.61	46.34
2027	47.56	48.06	48.25	47.42	46.99	47.31	47.50	46.95	47.64	47.82	47.04	47.25	47.48
2028	47.51	48.08	48.15	46.69	47.61	47.64	47.16	47.95	47.99	47.55	49.30	48.85	47.87
2029	50.72	50.56	50.97	49.48	50.45	51.48	51.01	51.82	51.18	52.09	53.34	52.89	51.34
2030	56.03	56.71	56.46	56.38	56.68	56.02	56.99	57.15	56.50	58.19	58.77	58.35	57.02
2031	60.45	60.33	59.55	59.06	59.30	58.36	59.34	58.79	59.57	59.84	60.18	61.18	59.66
2032	62.49	62.38	62.28	60.96	60.55	61.36	61.61	61.06	61.87	61.50	63.69	63.98	61.98
2033	64.93	65.55	65.61	64.35	63.94	64.79	64.31	65.23	65.35	65.12	67.17	67.49	65.32
2034	68.39	69.05	68.21	65.99	67.12	67.23	66.75	67.70	67.82	67.42	69.82	69.39	67.90
2035	71.74	71.65	70.84	68.56	69.71	69.28	68.79	69.76	69.10	70.51	71.88	71.66	70.29
2036	74.39	74.42	72.64	71.86	72.25	70.97	72.09	71.52	72.44	73.07	73.71	75.09	72.87
2037	77.31	77.23	75.51	74.67	74.26	74.58	74.89	74.31	75.25	75.94	76.62	78.07	75.71
2038	79.44	80.19	79.22	77.49	77.09	77.40	77.72	77.15	78.12	78.02	80.43	81.06	78.60
2039	82.54	83.29	82.27	80.46	80.05	80.36	79.87	80.94	81.12	81.03	83.53	84.21	81.63
2040	85.74	86.65	85.43	82.65	83.98	83.43	82.94	84.04	83.36	85.00	86.77	86.62	84.71
2041	90.00	89.94	87.91	86.77	87.23	85.77	87.04	87.31	86.61	88.32	90.18	90.04	88.09
2042	93.54	93.48	91.36	90.16	90.64	89.14	90.41	89.82	90.92	91.77	92.83	94.50	91.54

Portland General Electric
Avoided Cost Study
Projected On Peak Resource Sufficiency Period Forward Market Prices

Table 4 Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2017	43.57	30.73	9.33	10.60	15.19	22.58	31.49	34.81	29.46	26.91	27.42	33.53	26.26
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27	27.48
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34	27.36
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16	28.83
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13	30.33
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19	31.98
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07	30.00
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19	31.48
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Portland General Electric
Avoided Cost Study
Projected Off Peak Resource Sufficiency Period Forward Market Prices

Table 5 Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2017	31.49	25.89	2.71	5.21	3.22	6.53	19.27	24.51	24.72	23.85	24.11	27.42	18.29
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41	21.12
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38	20.80
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72	22.41
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97	23.95
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32	25.55
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77	27.53
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80	28.46
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Portland General Electric
Avoided Cost Study
Total Projected On Peak Avoided Capacity Costs

Table 6 Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	29.32	29.32	29.32	29.32	29.32	29.32	29.32	29.32	29.32	29.32	29.32	29.32
2026	29.91	29.91	29.91	29.91	29.91	29.91	29.91	29.91	29.91	29.91	29.91	29.91
2027	30.50	30.50	30.50	30.50	30.50	30.50	30.50	30.50	30.50	30.50	30.50	30.50
2028	31.11	31.11	31.11	31.11	31.11	31.11	31.11	31.11	31.11	31.11	31.11	31.11
2029	31.74	31.74	31.74	31.74	31.74	31.74	31.74	31.74	31.74	31.74	31.74	31.74
2030	32.37	32.37	32.37	32.37	32.37	32.37	32.37	32.37	32.37	32.37	32.37	32.37
2031	33.02	33.02	33.02	33.02	33.02	33.02	33.02	33.02	33.02	33.02	33.02	33.02
2032	33.47	33.47	33.47	33.47	33.47	33.47	33.47	33.47	33.47	33.47	33.47	33.47
2033	34.35	34.35	34.35	34.35	34.35	34.35	34.35	34.35	34.35	34.35	34.35	34.35
2034	35.15	35.15	35.15	35.15	35.15	35.15	35.15	35.15	35.15	35.15	35.15	35.15
2035	35.74	35.74	35.74	35.74	35.74	35.74	35.74	35.74	35.74	35.74	35.74	35.74
2036	36.34	36.34	36.34	36.34	36.34	36.34	36.34	36.34	36.34	36.34	36.34	36.34
2037	37.19	37.19	37.19	37.19	37.19	37.19	37.19	37.19	37.19	37.19	37.19	37.19
2038	37.93	37.93	37.93	37.93	37.93	37.93	37.93	37.93	37.93	37.93	37.93	37.93
2039	38.69	38.69	38.69	38.69	38.69	38.69	38.69	38.69	38.69	38.69	38.69	38.69
2040	39.46	39.46	39.46	39.46	39.46	39.46	39.46	39.46	39.46	39.46	39.46	39.46
2041	40.25	40.25	40.25	40.25	40.25	40.25	40.25	40.25	40.25	40.25	40.25	40.25
2042	41.06	41.06	41.06	41.06	41.06	41.06	41.06	41.06	41.06	41.06	41.06	41.06

Portland General Electric
Avoided Cost Study
Total Projected Off Peak Avoided Capacity Costs

Table 7

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
Avoided Cost Study
Total Projected Other Fixed Avoided Costs

Table 8

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58
2026	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67
2027	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76
2028	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84
2029	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95
2030	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05
2031	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15	5.15
2032	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24
2033	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36	5.36
2034	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47
2035	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
2036	5.67	5.67	5.67	5.67	5.67	5.67	5.67	5.67	5.67	5.67	5.67	5.67
2037	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80
2038	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92
2039	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04
2040	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14	6.14
2041	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28
2042	6.41	6.41	6.41	6.41	6.41	6.41	6.41	6.41	6.41	6.41	6.41	6.41

Portland General Electric
Avoided Cost Study
Total Projected Avoided Variable O&M Costs

Table 9

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
2026	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36
2027	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43
2028	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
2029	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56
2030	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64
2031	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
2032	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78
2033	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86	3.86
2034	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
2035	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01
2036	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09	4.09
2037	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18
2038	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26	4.26
2039	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35
2040	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43
2041	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52
2042	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61

Portland General Electric
Avoided Cost Study
Total Projected Avoided Fuel Costs

Table 10

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	20.09	20.21	20.30	19.59	19.56	19.48	19.58	19.66	19.78	19.88	20.62	20.73
2026	21.24	21.36	21.40	20.68	20.69	20.76	20.86	20.96	21.09	21.23	22.09	22.22
2027	22.31	22.44	22.35	21.61	21.75	21.50	21.60	21.70	21.83	22.57	21.23	21.35
2028	21.78	21.86	21.74	21.07	21.21	21.32	21.43	21.54	21.67	21.81	22.99	23.12
2029	23.78	23.90	24.02	23.33	23.50	24.62	24.74	24.87	25.02	25.14	26.49	26.63
2030	28.54	29.53	29.67	28.99	29.19	29.35	29.50	29.66	29.83	30.71	31.38	31.56
2031	32.42	32.60	32.22	31.12	31.26	31.15	31.30	31.46	31.63	31.80	32.97	33.14
2032	34.04	34.12	33.82	32.60	32.81	33.00	33.15	33.32	33.51	33.76	35.32	35.53
2033	36.50	36.70	36.45	35.28	35.51	35.72	35.88	36.06	36.28	36.69	38.11	38.32
2034	39.33	39.55	38.39	37.05	37.30	37.51	37.69	37.89	38.11	38.36	40.10	40.33
2035	41.39	41.63	40.49	39.11	39.36	39.03	39.22	39.42	39.66	40.16	41.63	42.08
2036	43.52	43.76	42.56	41.09	41.38	41.01	41.21	41.43	41.68	42.20	43.75	44.22
2037	45.74	46.00	44.74	43.21	43.48	43.11	43.32	43.54	43.79	44.37	45.98	46.50
2038	48.06	48.34	47.01	45.39	45.70	45.31	45.52	45.76	46.03	46.63	48.34	48.86
2039	50.52	50.80	49.42	47.72	48.04	47.62	47.85	48.10	48.38	49.01	50.80	51.36
2040	53.10	53.39	51.94	50.15	50.49	50.05	50.30	50.55	50.86	51.52	53.39	53.98
2041	55.82	56.14	54.60	52.71	53.06	52.61	52.86	53.13	53.44	54.15	56.12	56.73
2042	58.68	59.00	57.38	55.41	55.78	55.31	55.55	55.84	56.18	56.91	59.00	59.64

UM 1728 Application to Update Schedule 201 Qualifying Facility Information

Attachment B
Description of Renewable Avoided Costs

PORTLAND GENERAL ELECTRIC COMPANY
RENEWABLE AVOIDED COST STUDY
2016 IRP UPDATE
August 18, 2017

Introduction

This renewable avoided cost update is made consistent with PGE's 2016 Integrated Resource Plan (IRP). The Commission directs electric utilities to make an avoided cost filing within 30 days of IRP acknowledgement.

Integrated Resource Plan

The Commission partially acknowledged PGE's 2016 IRP on August 8, 2017. The 2016 IRP forms the basis of most of the inputs in this avoided cost study.

Resource Timing

The renewable resource deficiency period starts in 2029, consistent with the Commission August 8, 2017 acknowledgement decision.

Avoided Cost Estimates

Renewable avoided cost prices beginning January 2029 are represented by the fully allocated costs of a renewable wind resource. Tables 1 through 8 (following) summarize PGE avoided cost data consistent with Commission Order Nos. 05-584 and 11-505. Tables 1 and 2 are estimates of monthly on- and off-peak renewable avoided costs for twenty years beginning in 2017 prior to removing capacity and shaping energy. Tables 3 and 4 are energy prices prior to shaping.

The on- and off-peak prices in Tables 5 and 6 are developed using the on- and off-peak prices from PGE's AURORA model. On-peak periods are from 6 a.m. through 10 p.m. Mondays through Saturdays. The off-peak hours are from 10 p.m. until 6 a.m. Mondays through Saturdays and all twenty-four hours on Sunday. Tables 7 and 8 show the on- and off-peak resource sufficiency rates. The renewable resource sufficiency period prices (expressed in $/MWh or mills/kWh) for the years 2017 through 2028, are based on forward electricity curves, and represent capacity and energy avoided costs.

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Resource Sufficiency Period Pricing

Renewable resource sufficiency period prices are based on forward Mid-Columbia electricity trading curves delivered to PGE's system. The forward trading curves are dated July 13, 2017.

Renewable Capacity Contribution

To translate the renewable capacity contribution into prices for renewable avoided costs consistent with Order No. 16-174, several inputs are necessary. First, the capacity contribution percentages of both wind and solar resources are necessary. The capacity contribution percentages are provided in PGE's 2016 IRP. The capacity contribution for wind is 18.59% and the capacity contribution for solar is 15.33%. Three additional inputs are necessary:

(1) The capacity factor of the proxy wind resource of 34.00% is an existing input already provided in the renewable avoided cost model.
(2) The on-peak capacity factor of the wind resource of 35.24% is calculated from the wind resource used to derive the capacity contribution for wind.
(3) The on-peak capacity factor of the solar resource of 35.61% is calculated from the solar resource used to derive the capacity contribution for solar.

The translation of renewable capacity contribution into avoided cost prices is performed in two simple steps.

Step one: remove capacity value from all hours for the proxy wind resource.

Step two: add capacity in the on-peak hours for wind and solar QFs separately.

The proxy wind resource used to calculate prices in the deficiency period includes both energy and capacity. In the first step, capacity is removed from all hours using this formula:

(SCCT $/kW-year X wind capacity contribution percentage) / (number of annual hours X annual capacity factor of the proxy wind resource)*

Step two is performed for wind and solar avoided QFs separately. For solar QFs, capacity is added into the on peak hours using this formula:

(SCCT $/kW-year X solar capacity contribution percentage) / (number of on-peak hours X solar on-peak capacity factor)*

* Additional adjustments are included for inflation and line losses.

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The above formula is used for wind QFs using the wind capacity contribution percentage and wind on-peak capacity factor.

Production Tax Credit

The Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301) extended the PTC. The Act also created a phase-down in the PTC; amount for wind facilities commencing construction in 2017, 2018, or 2019. The Act eliminates the PTC for wind facilities commencing construction in 2020 or later.

No PTC is assumed in this filing since construction on a facility to meet an online date of 2029 is unlikely to commence before 2020.

Portland General Electric
Renewable Avoided Cost Study
Total Projected On-Peak Avoided Costs

Table 1

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	36.28	36.45	32.07	27.15	25.16	20.76	31.18	33.59	36.96	36.50	36.17	38.88
2026	38.02	38.42	34.69	28.61	23.72	19.90	33.16	36.49	39.07	39.98	39.93	41.34
2027	40.65	40.65	35.03	29.55	25.62	19.81	33.68	38.68	40.37	41.18	39.95	42.49
2028	41.59	39.62	35.61	29.31	24.13	18.69	35.04	39.47	41.56	42.04	42.77	45.50
2029	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85
2030	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65
2031	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48
2032	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09
2033	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26
2034	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20
2035	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18
2036	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93
2037	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27
2038	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38
2039	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52
2040	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41
2041	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95
2042	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23
2043	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55

Portland General Electric
Renewable Avoided Cost Study
Total Projected Off-Peak Avoided Costs

Table 2

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	33.70	32.17	29.76	25.01	21.99	19.00	26.39	30.90	33.57	33.77	33.61	34.83
2026	35.44	35.59	31.64	27.21	22.20	15.26	28.97	33.61	36.07	35.46	35.51	37.70
2027	36.66	35.71	32.22	27.60	23.64	18.12	29.40	34.72	37.35	37.55	36.31	38.40
2028	38.09	37.21	33.20	27.82	23.65	17.34	31.56	36.38	38.22	38.77	39.08	40.92
2029	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85	89.85
2030	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65	91.65
2031	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48	93.48
2032	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09	95.09
2033	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26	97.26
2034	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20
2035	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18	101.18
2036	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93	102.93
2037	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27	105.27
2038	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38	107.38
2039	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52	109.52
2040	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41	111.41
2041	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95	113.95
2042	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23	116.23
2043	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55	118.55

Portland General Electric
Renewable Avoided Cost Study
Total Projected On-Peak Avoided Costs: Capacity Removed, Energy Only

Table 3

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	36.28	36.45	32.07	27.15	25.16	20.76	31.18	33.59	36.96	36.50	36.17	38.88
2026	38.02	38.42	34.69	28.61	23.72	19.90	33.16	36.49	39.07	39.98	39.93	41.34
2027	40.65	40.65	35.03	29.55	25.62	19.81	33.68	38.68	40.37	41.18	39.95	42.49
2028	41.59	39.62	35.61	29.31	24.13	18.69	35.04	39.47	41.56	42.04	42.77	45.50
2029	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44
2030	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05
2031	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69
2032	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13
2033	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07
2034	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82
2035	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59
2036	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15
2037	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25
2038	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14
2039	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06
2040	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75
2041	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02
2042	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06
2043	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14

Portland General Electric
Renewable Avoided Cost Study
Total Projected Off-Peak Avoided Costs: Capacity Removed, Energy Only

Table 4

Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	33.70	32.17	29.76	25.01	21.99	19.00	26.39	30.90	33.57	33.77	33.61	34.83
2026	35.44	35.59	31.64	27.21	22.20	15.26	28.97	33.61	36.07	35.46	35.51	37.70
2027	36.66	35.71	32.22	27.60	23.64	18.12	29.40	34.72	37.35	37.55	36.31	38.40
2028	38.09	37.21	33.20	27.82	23.65	17.34	31.56	36.38	38.22	38.77	39.08	40.92
2029	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44	80.44
2030	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05	82.05
2031	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69	83.69
2032	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13	85.13
2033	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07	87.07
2034	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82	88.82
2035	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59	90.59
2036	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15	92.15
2037	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25	94.25
2038	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14	96.14
2039	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06	98.06
2040	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75	99.75
2041	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02	102.02
2042	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06	104.06
2043	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14	106.14

Portland General Electric
Renewable Avoided Cost Study
Total Projected On-Peak Avoided Costs: Capacity Removed, Energy Only, Aurora Shaping

Table 5 Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	36.28	36.45	32.07	27.15	25.16	20.76	31.18	33.59	36.96	36.50	36.17	38.88
2026	38.02	38.42	34.69	28.61	23.72	19.90	33.16	36.49	39.07	39.98	39.93	41.34
2027	40.65	40.65	35.03	29.55	25.62	19.81	33.68	38.68	40.37	41.18	39.95	42.49
2028	41.59	39.62	35.61	29.31	24.13	18.69	35.04	39.47	41.56	42.04	42.77	45.50
2029	98.73	90.42	83.19	67.70	59.55	35.00	79.98	91.66	98.98	94.04	95.69	105.85
2030	98.71	96.15	85.45	66.34	52.32	30.61	82.43	92.35	101.20	100.41	98.44	107.82
2031	98.62	97.84	87.42	65.69	58.57	42.31	80.40	94.18	101.65	99.62	96.41	105.97
2032	101.16	98.81	85.58	67.42	55.88	33.18	86.53	102.70	103.85	101.28	104.99	110.86
2033	102.89	102.55	85.26	67.39	52.36	51.67	88.28	99.33	104.46	103.29	105.37	109.93
2034	107.70	107.26	88.56	68.38	53.43	38.13	91.98	102.42	107.62	108.28	109.70	115.66
2035	113.08	106.79	91.16	67.49	55.89	32.09	87.40	103.72	110.12	108.00	106.67	117.34
2036	113.61	108.13	92.63	69.65	46.57	19.26	94.79	105.70	113.96	112.65	111.24	121.91
2037	113.12	112.66	95.63	67.20	53.95	40.01	92.50	107.68	115.15	112.29	112.29	122.80
2038	115.66	117.76	93.41	66.69	47.01	32.07	101.89	117.27	120.17	117.48	118.25	127.40
2039	116.68	115.16	92.00	66.79	55.87	42.04	101.48	112.88	119.00	112.36	116.60	123.77
2040	118.13	116.33	93.33	75.43	48.09	35.54	106.03	116.70	124.04	119.31	121.60	130.47
2041	121.70	118.06	98.83	79.53	69.52	23.25	104.49	118.96	125.24	115.90	116.38	128.22
2042	123.66	121.34	102.27	79.83	52.17	23.60	108.04	122.78	128.29	122.10	119.94	134.87
2043	122.16	123.35	99.46	72.94	58.09	47.87	111.16	125.04	130.94	122.06	123.56	138.81

Portland General Electric
Renewable Avoided Cost Study
Total Projected Off-Peak Avoided Costs: Capacity Removed, Energy Only, Aurora Shaping

Table 6 Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	33.70	32.17	29.76	25.01	21.99	19.00	26.39	30.90	33.57	33.77	33.61	34.83
2026	35.44	35.59	31.64	27.21	22.20	15.26	28.97	33.61	36.07	35.46	35.51	37.70
2027	36.66	35.71	32.22	27.60	23.64	18.12	29.40	34.72	37.35	37.55	36.31	38.40
2028	38.09	37.21	33.20	27.82	23.65	17.34	31.56	36.38	38.22	38.77	39.08	40.92
2029	87.39	83.14	79.75	60.89	56.60	30.37	68.86	84.70	91.46	89.10	90.05	95.00
2030	90.66	87.81	81.88	62.46	52.25	31.31	75.55	87.01	93.96	93.87	94.23	96.33
2031	94.53	91.33	79.90	66.32	59.86	41.01	74.22	87.92	95.40	93.03	92.05	96.31
2032	95.12	90.63	85.26	64.49	46.09	33.03	81.76	88.62	98.19	95.17	97.79	103.88
2033	96.72	93.73	84.37	65.02	55.14	44.09	81.80	90.25	98.91	96.03	97.55	104.35
2034	100.64	96.93	84.22	63.90	50.21	33.88	82.22	94.26	101.29	101.38	105.38	107.75
2035	103.38	100.59	93.20	71.90	61.31	46.52	81.06	99.14	104.45	99.35	103.56	106.09
2036	111.16	105.72	94.24	72.48	61.23	31.45	82.90	100.58	110.79	104.85	108.44	114.13
2037	110.15	107.49	96.32	79.57	59.61	38.00	86.10	101.85	110.09	103.94	105.91	113.12
2038	113.74	110.37	97.67	79.06	51.82	34.44	88.62	103.26	110.27	107.20	111.44	117.93
2039	110.16	108.78	96.61	84.94	62.94	60.33	93.55	103.97	110.69	110.48	115.32	122.80
2040	116.99	108.93	94.17	91.82	59.51	40.97	95.01	110.61	112.45	116.09	118.19	121.07
2041	116.50	110.73	111.72	97.32	66.46	37.99	97.97	109.98	123.17	113.27	119.57	123.40
2042	126.11	116.45	107.55	85.50	62.50	40.12	105.67	116.39	125.76	123.46	122.21	128.97
2043	120.84	117.22	106.74	92.45	75.66	55.17	95.95	115.68	123.02	118.73	119.21	130.15

Portland General Electric

Renewable Avoided Cost Study
Projected On Peak Resource Sufficiency Period Forward Market Prices

Table 7 Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								34.81	29.46	26.91	27.42	33.53
2018	32.01	29.46	25.38	21.14	20.62	21.14	30.01	33.42	31.06	25.63	27.67	32.27
2019	31.18	29.49	23.89	19.25	18.62	19.53	30.14	34.47	31.43	26.91	28.93	34.34
2020	32.84	31.06	25.15	20.26	19.59	20.56	31.74	36.30	33.09	28.33	30.46	36.16
2021	34.60	32.72	26.46	21.28	20.58	21.61	33.44	38.27	34.87	29.82	32.09	38.13
2022	36.47	34.48	27.88	22.42	21.68	22.76	35.25	40.34	36.75	31.44	33.81	40.19
2023	32.55	32.48	28.51	25.11	23.14	21.85	28.29	31.03	33.38	33.87	34.01	36.07
2024	36.16	34.47	31.84	26.04	23.28	16.27	29.02	32.72	35.73	35.93	36.83	39.19
2025	36.28	36.45	32.07	27.15	25.16	20.76	31.18	33.59	36.96	36.50	36.17	38.88
2026	38.02	38.42	34.69	28.61	23.72	19.90	33.16	36.49	39.07	39.98	39.93	41.34
2027	40.65	40.65	35.03	29.55	25.62	19.81	33.68	38.68	40.37	41.18	39.95	42.49
2028	41.59	39.62	35.61	29.31	24.13	18.69	35.04	39.47	41.56	42.04	42.77	45.50

Portland General Electric
Renewable Avoided Cost Study
Projected Off Peak Resource Sufficiency Period Forward Market Prices

Table 8 Nominal $/MWh

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017								24.51	24.72	23.85	24.11	27.42
2018	27.42	24.87	20.80	15.18	12.12	10.88	19.58	24.24	24.69	22.51	23.69	27.41
2019	24.42	24.61	19.29	13.46	10.42	10.07	19.15	25.06	25.53	23.33	24.87	29.38
2020	26.35	26.55	20.80	14.48	11.19	10.80	20.64	27.03	27.54	25.17	26.84	31.72
2021	28.18	28.40	22.20	15.39	11.85	11.44	22.03	28.92	29.47	26.90	28.71	33.97
2022	30.11	30.34	23.71	16.42	12.61	12.18	23.53	30.91	31.50	28.75	30.68	36.32
2023	30.45	29.46	27.13	22.78	21.22	19.28	25.24	28.22	30.91	31.13	31.55	32.77
2024	32.49	29.95	29.34	24.83	21.55	13.81	25.44	29.61	32.06	32.27	34.41	35.80
2025	33.70	32.17	29.76	25.01	21.99	19.00	26.39	30.90	33.57	33.77	33.61	34.83
2026	35.44	35.59	31.64	27.21	22.20	15.26	28.97	33.61	36.07	35.46	35.51	37.70
2027	36.66	35.71	32.22	27.60	23.64	18.12	29.40	34.72	37.35	37.55	36.31	38.40
2028	38.09	37.21	33.20	27.82	23.65	17.34	31.56	36.38	38.22	38.77	39.08	40.92

UM 1728 Application to Update Schedule 201 Qualifying Facility Information

Attachment C

List of Sources for Various Assumptions Used to Calculate Prices

Portland General Electric
Sched 201 Workbooks
Major Input Source Notes
August 2017

Model	Worksheet	Item	Source	Source Detail
RAC	Capacity	Capacity Contribution	2016 IRP	Section 5.1.5
RAC	Capacity	On Peak Capacity Factor	2016 IRP	Section 5.1.5
RAC	CAPEX	Ongoing annual capital costs	2016 IRP	Appendix M
RAC	Plant Capital Cost Inputs	Overnight Capital Cost	2016 IRP	Chapter 7, p. 212, Table 7-4; Appendix M, Section 3.2.1
RAC	Plant Capital Cost Inputs	Capacity	2016 IRP	Chapter 7, p. 212, Table 7-4
RAC	Plant Capital Cost Inputs	Economic Life	2016 IRP	Chapter 7, p. 212, Table 7-4
RAC	Plant Operating Parameters	Fixed O&M	2016 IRP	Chapter 7, p. 212, Table 7-4; Appendix M, Sections 3.2.4 - 3.2.6
RAC	Plant Operating Parameters	Capacity Factor	2016 IRP	Appendix M, Section 3.1.2
RAC	Plant Operating Parameters	Wind and Solar Integration Costs	2016 IRP	Section 7.2.1.2
RAC	Financial & Tax Parameters	Tax Rates, Inflation, Cost of Capital	2016 IRP	Section 10.2.1.3
RAC	Financial & Tax Parameters	In Service Year	2016 IRP	Staff Report, July 28, 2017; OPUC Public Meeting, August 8, 2017; PGE's June 23, 2017 Reply Comments page 45
RAC	Trading Curves	On/Off-Peak Prices	PGE Trading Curves 2016-2022, 2023+ from Aurora PNW prices based on 2016 IRP model with updated gas prices	Chapter 10
RAC	Transmission	BPA PTP + SCD	BPA Rates 2016-2019, 2016 IRP inflation assumption after 2019.	
SAC	Plant Cap Cost	Overnight Capital Cost	2016 IRP	Chapter 7, p. 212, Table 7-4; Appendix K
SAC	Plant Cap Cost	Capacity	2016 IRP	Chapter 7, p. 212, Table 7-4; Appendix K
SAC	Plant Cap Cost	Economic Life	2016 IRP	Chapter 7, p. 212, Table 7-4
SAC	Plant Oper	Heat Rate	2016 IRP	Chapter 7, p. 212, Table 7-4; Appendix K
SAC	Plant Oper	Fixed O&M	2016 IRP	Chapter 7, p. 212, Table 7-4; Appendix K
SAC	Gas Prices	AECO Delivered	2016 IRP framework, updated June 2017 Wood MacKenzie North America Natural Gas Long-Term Outlook	Chapter 3
SAC	Aurora	CCCT generation, starts, start costs	2016 IRP	Aurora output
SAC	Plant Cap Cost	In Service Year	2016 IRP	Staff Report, July 28, 2017; OPUC Public Meeting, August 8, 2017; PGE's June 23, 2017 Reply Comments page 45

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of **Portland General Electric Company's Application to Update Schedule 201 Qualifying Facility Information – Compliance Filing and Motion for Temporary Relief from Schedule201 Prices** on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

Dated this 18th day of August, 2017.

____

Barbara Parr
Legal Assistant
Portland General Electric Company
121 SW Salmon St., 1WTC1301
Portland, OR 97204
(503) 464-8872 (Telephone)
Barbara.parr@pgn.com

SERVICE LIST
OPUC DOCKET UM 1610
8/18/17

JENNIFER SOLOMON
EXELON BUSINESS SERVICES COMPANY, LLC
100 CONSTELLATION WAY, SUITE 500-C
BALTIMORE MD 21202
jennifer.solomon@exeloncorp.com

BIOMASS ONE LP

DAVID A LOKTING
STOLL BERNE
209 SW OAK STREET, SUITE 500
PORTLAND OR 97204
dlokting@stollberne.com

CORONAL DEVELOPMENT SERVICES

ANDREW FOUKAL
CORONAL DEVELOPMENT SERVICES
17 4TH ST, STE B
CHARLOTTESVILLE VA 22902
afoukal@coronalgroup.com

CAROLINE WHITTINGHILL
CORONAL DEVELOPMENT SERVICES
2120 UNIVERSITY AVE
BERKELEY CA 94704
cwhittinghill@coronalgroup.com

CREA UM 1610

GREGORY M. ADAMS
RICHARDSON ADAMS, PLLC
PO BOX 7218
BOISE ID 83702
greg@richardsonadams.com

PETER J RICHARDSON
RICHARDSON ADAMS, PLLC
PO BOX 7218
BOISE ID 83707
peter@richardsonadams.com

BRIAN SKEAHAN
CREA
PMB 409
18160 COTTONWOOD RD
SUNRIVER OR 97707
brian.skeahan@yahoo.com

ENERGY TRUST UM 1610

BETSY KAUFFMAN
ENERGY TRUST OF OREGON
421 SW OAK ST; STE 300
PORTLAND OR 97204
betsy.kauffman@energytrust.org

THAD ROTH
ENERGY TRUST OF OREGON
421 SW OAK STE 300
PORTLAND OR 97204
thad.roth@energytrust.org

JOHN M VOLKMAN
ENERGY TRUST OF OREGON
421 SW OAK ST #300
PORTLAND OR 97204
john.volkman@energytrust.org

GARDNER CAPITAL SOLAR DEVELOPMENT LLC

THOMAS MCCANN MULLOOLY
FOLEY & LARDNER LLP
3000 K STREET NW, STE 600
WASHINGTON DC 20007-5109
tmullooly@foley.com

KURT REMPE
FOLEY & LARDNER, LLP
3000 K STREET NW, STE 600
WASHINGTON DC 20007-5109
krempe@foley.com

ICNU UM 1610

TYLER C PEPPLE
DAVISON VAN CLEVE, PC
333 SW TAYLOR SUITE 400
PORTLAND OR 97204
tcp@dvclaw.com

S BRADLEY VAN CLEVE
DAVISON VAN CLEVE PC
333 SW TAYLOR - STE 400
PORTLAND OR 97204
bvc@dvclaw.com

IDAHO POWER UM 1610

JULIA HILTON
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
jhilton@idahopower.com

LISA F RACKNER
MCDOWELL RACKNER & GIBSON PC
419 SW 11TH AVE., SUITE 400
PORTLAND OR 97205
dockets@mrg-law.com

DONOVAN E WALKER
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
dwalker@idahopower.com

SERVICE LIST
OPUC DOCKET UM 1610
8/18/17

NORTHWEST ENERGY SYSTEMS

DAREN ANDERSON
NORTHWEST ENERGY SYSTEMS COMPANY LLC
1800 NE 8TH ST., STE 320
BELLEVUE WA 98004-1600
da@thenescogroup.com

OBSIDIAN UM 1610

DAVID BROWN
OBSIDIAN RENEWABLES, LLC
5 CENTERPOINT DR, STE 590
LAKE OSWEGO OR 97035
dbrown@obsidianrenewables.com

TODD GREGORY
OBSIDIAN RENEWABLES, LLC
5 CENTERPOINTE DR, STE 590
LAKE OSWEGO OR 97035
tgregory@obsidianrenewables.com

CHAD M STOKES
CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP
1001 SW 5TH - STE 2000
PORTLAND OR 97204-1136
cstokes@cablehuston.com

ODOE UM 1610

DIANE BROAD
OREGON DEPARTMENT OF ENERGY
625 MARION ST NE
SALEM OR 97301-3737
diane.broad@state.or.us

JESSE D. RATCLIFFE
OREGON DEPARTMENT OF ENERGY
1162 COURT ST NE
SALEM OR 97301-4096
jesse.d.ratcliffe@doj.state.or.us

WENDY SIMONS
OREGON DEPARTMENT OF ENERGY
625 MARION ST NE
SALEM OR 97301
wendy.simons@oregon.gov

ONEENERGY INC

BILL EDDIE
ONE ENERGY RENEWABLES
206 NE 28TH AVE, STE 202
PORTLAND OR 97232
bill@oneenergyrenewables.com

KENNETH KAUFMANN
1785 WILLAMETTE FALLS DR, STE 5
WEST LINN OR 97068
ken@kaufmann.law

OREGON CITIZENS UTILITY BOARD

OREGON CITIZENS' UTILITY BOARD
610 SW BROADWAY, STE 400
PORTLAND OR 97205
dockets@oregoncub.org

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

ROBERT JENKS
OREGON CITIZENS' UTILITY BOARD
610 SW BROADWAY, STE 400
PORTLAND OR 97205
bob@oregoncub.org

OREGON SOLAR ENERGY INDUSTRIES ASSOCIATION

OREGON SOLAR ENERGY INDUSTRIES ASSOC.
PO BOX 14927
PORTLAND OR 97293-0927
dockets@oseia.org

ERICA NIST-LUND
OSEIA
erica@oseia.org

OREGONIANS FOR RENEWABLE ENERGY PROGRESS

MARK PETE PENGILLY
OREGONIANS FOR RENEWABLE ENERGY PROGRESS
PO BOX 10221
PORTLAND OR 97296
mpengilly@gmail.com

PACIFICORP UM 1610

PACIFICORP, DBA PACIFIC POWER
825 NE MULTNOMAH ST, STE 2000
PORTLAND OR 97232
oregondockets@pacificorp.com

ERIN APPERSON
PACIFIC POWER
825 NE MULTNOMAH STE 800
PORTLAND OR 97232
erin.apperson@pacificorp.com

SERVICE LIST
OPUC DOCKET UM 1610
8/18/17

ETTA LOCKY
PACIFIC POWER
825 NE MULTNOMAH ST., STE 2000
PORTLAND OR 97232
etta.lockey@pacificorp.com

PGE UM 1610

DENISE SAUNDERS
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST - 1WTC1711
PORTLAND OR 97204
denise.saunders@pgn.com

JAY TINKER
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST 1WTC-0306
PORTLAND OR 97204
pge.opuc.filings@pgn.com

RENEWABLE ENERGY COALITION

JOHN LOWE
RENEWABLE ENERGY COALITION
12050 SW TREMONT ST
PORTLAND OR 97225-5430
jravenesanmarcos@yahoo.com

IRION A SANGER
SANGER LAW PC
1117 SE 53RD AVE
PORTLAND OR 97215
irion@sanger-law.com

SIDNEY VILLANUEVA
SANGER LAW, PC
1117 SE 53RD AVE
PORTLAND OR 97215
sidney@sanger-law.com

RENEWABLE NORTHWEST UM 1610

RENEWABLE NORTHWEST
421 SW 6TH AVE., STE. 1125
PORTLAND OR 97204
dockets@renewablenw.org

DINA DUBSON KELLEY
RENEWABLE NORTHWEST
421 SW 6TH AVE STE 1125
PORTLAND OR 97204
dina@renewablenw.org

JOHN W STEPHENS
ESLER STEPHENS & BUCKLEY
121 SW MORRISON ST STE 700
PORTLAND OR 97204-3183
stephens@eslerstephens.com;
mec@eslerstephens.com

SMALL BUSINESS UTILITY ADVOCATES

JAMES BIRKELUND
SMALL BUSINESS UTILITY ADVOCATES
548 MARKET ST STE 11200
SAN FRANCISCO CA 94104
james@utilityadvocates.org

DIANE HENKELS
CLEANTECH LAW PARTNERS PC
420 SW WASHINGTON ST STE 400
PORTLAND OR 97204
dhenkels@cleantechlaw.com

STAFF UM 1610

BRITTANY ANDRUS
PUBLIC UTILITY COMMISSION OF OREGON
PO BOX 1088
SALEM OR 97308-1088
brittany.andrus@state.or.us

STEPHANIE S ANDRUS
PUC STAFF--DEPARTMENT OF JUSTICE
BUSINESS ACTIVITIES SECTION
1162 COURT ST NE
SALEM OR 97301-4096
stephanie.andrus@state.or.us

NOLAN MOSER
OREGON PUBLIC UTILITY COMMISSION
PO BOX 1088
SALEM OR 97308
nolan.moser@state.or.us

THREEMILE CANYON WIND I LLC

JOHN HARVEY
EXELON WIND LLC
4601 WESTOWN PARKWAY, STE 300
WEST DES MOINES IA 50266
john.harvey@exeloncorp.com

Richard Lorenz
CABLE HUSTON BENEDIT HAAGENSEN & LLOYD LLP
1001 SW FIFTH AVE - STE 2000
PORTLAND OR 97204-1136
rlorenz@cablehuston.com

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: September 12, 2017

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __**September 18, 2017**__

DATE: September 7, 2017

TO: Public Utility Commission

FROM: Brittany Andrus

THROUGH: Jason Eisdorfer and John Crider

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1728) Updates Schedule 201, Qualifying Facility Information.

STAFF RECOMMENDATION:

Staff recommends that the Commission issue an order directing Portland General Electric (PGE) to file a modified Schedule 201 to be effective two days after filing, but no sooner than September 18, 2017.

DISCUSSION:

Issue

Whether the Commission should approve PGE's post-Integrated Resource Plan (IRP) revisions to Schedule 201, which contain the power prices for qualifying facilities (QFs) eligible for standard prices.

Applicable Rules, Orders and Statutes

OAR 860-029-0080 provides, in relevant part:

(3) Each public utility shall file with the Commission draft avoided-cost information with its least-cost plan[1] pursuant to Order No. 89-507 and file final avoided-cost information within 30 days of Commission acknowledgment of the least-cost plan to be effective 30 days after filing. The information submitted shall be maintained for public inspection and include the following data for calculating avoided costs:

[1] The term "least cost plan" is equivalent to "integrated resource plan," or "IRP."

(a) The estimated avoided costs on its system, solely with respect to the energy component, for expected levels of purchases from qualifying facilities. The levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1,000 megawatts or more and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1,000 megawatts. The avoided costs shall be stated on a cents-per-kWh basis, during peak and off-peak periods, by year, for the current calendar year and each of the next five years; and

(b) The public utility's estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kW, and the associated energy costs of each addition or purchase, expressed in cents per kWh. These costs shall be expressed in terms of individual generating resources and of individual, planned firm purchases.

* * * * *

(6) State review: Any data submitted by a public utility under this rule shall be subject to review and approval by the Commission. In any such review, the public utility has the burden of supporting and justifying its data. Any standard rates filed under OAR 860-029-0040 shall be subject to suspension and modification by the Commission.

<u>Analysis</u>

Background
On August 18, 2017, PGE filed updated avoided costs ten days after the August 8, 2017, public meeting at which the Commission addressed acknowledgment of the Company's 2016 IRP.

Discussion
The proposed updated avoided costs in PGE's August 18, 2017, filing are based on inputs from the 2016 IRP and on updated forward gas and electricity prices. The proposed avoided costs in PGE's August 18, 2017, filing update PGE's current standard avoided costs that went into effect on May 19, 2017, following the May 1 annual update for this year

Staff's analysis of PGE's avoided cost filing focused on five primary issues:

1. Nonrenewable deficiency period
2. Renewable deficiency period
3. Deficiency period monthly price calculations
4. Integration charges
5. Effective date

1. Nonrenewable deficiency period

In its explanation of the proposed nonrenewable avoided cost calculations, PGE states, "[t]he resource deficiency period for nonrenewable resources starts in 2025, consistent with the Commission's August 8, 2017, acknowledgment decisions."[2]

Staff disagrees that the Commission acknowledged a capacity need for PGE beginning in 2025. At the August 8 public meeting, the Commission acknowledged PGE's capacity need of 561 megawatts (MW) in 2021, and designated a series of steps for the Company to use in addressing this need. Staff concludes that the nonrenewable avoided costs should be recalculated using the 2021 deficiency period.

Staff recognizes that PGE has filed an application for waiver of the competitive bidding guidelines, which may or may not lead to a change in nonrenewable sufficiency status.[3] Staff does not support taking those potential outcomes into consideration at this time.

2. Renewable deficiency period

PGE calculates its renewable avoided costs using a renewable resource deficiency period beginning in 2029. Staff supports this demarcation as it is consistent with the Commission's August 8, 2017, decision to not acknowledge the Company's action item to acquire significant renewable resources by the end of 2020. Similar to Staff's position on the nonrenewable deficiency period, Staff does not support taking any potential supplemental action plan filings into consideration. The regulatory renewable portfolio standard need has been clearly defined for 2029. To the extent PGE or the Commission takes action in the future that impacts the start date of the next deficiency period, such actions *may* serve as a basis for an out-of-cycle update to avoided cost prices.[4]

[2] PGE Standard Avoided Cost Study, 2016 IRP Update, August 18, 2017, p. 1.
[3] Docket No. UM 1892, Portland General Electric Waiver for Competitive Bidding Guidelines, filed August 25, 2017.
[4] Staff does not suggest that any action would necessarily result in a mid-cycle update, only that there is potential for such an update if circumstances warrant.

3. Deficiency period monthly price calculations

Below are shaded deficiency period renewable prices for the three QF types as proposed in this filing. The shading is darker at the lower prices and lighter at higher prices. Logically, absent a specific event or driver, prices should trend in the same direction year over year. However, especially in the months of May and June, that trend is not seen.

Renewable Fixed Price Option On-Peak $/MWh

	Base Load QF		**Wind QF**		**Solar QF**	
	May	Jun	May	Jun	May	Jun
2029	91.28	66.74	74.34	49.80	71.42	46.88
2030	84.69	62.99	67.41	45.70	64.43	42.73
2031	91.59	75.33	73.97	57.71	70.93	54.67
2032	89.34	66.65	71.47	48.78	68.40	45.70
2033	86.72	86.02	68.38	67.68	65.22	64.52
2034	88.59	73.28	69.82	54.52	66.59	51.28
2035	91.63	67.83	72.56	48.75	69.27	45.47
2036	82.91	55.60	63.51	36.20	60.16	32.86
2037	91.13	77.19	71.28	57.35	67.86	53.93
2038	84.94	70.00	64.69	49.75	61.20	46.26
2039	94.56	80.72	73.91	60.08	70.35	56.52
2040	87.55	75.00	66.49	53.93	62.86	50.30
2041	109.77	63.50	88.28	42.01	84.58	38.31
2042	93.22	64.66	71.31	42.74	67.53	38.97

Staff concludes that there is a systemic error in the price calculations and that they should not be approved as filed. PGE should investigate and propose revised prices that are not anomalous, or provide a detailed explanation of the underlying factors that result in these patterns. Staff has informally discussed this issue with PGE and the Company has agreed to propose an adjustment.

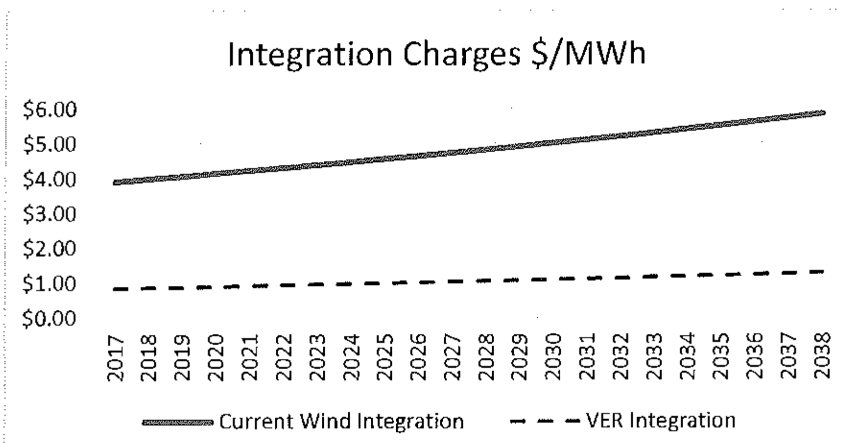
Additionally, documentation accompanying the workpapers for this filing includes a list of notes about the source for the inputs. Staff appreciates PGE's effort to draw a more direct line from the IRP document to the avoided cost calculations. Staff highlights below a key input that is not evident from the workpapers and documentation.
The calculation of the capacity payment, as directed by the Commission in Order No. 16-174 (Docket No. UM 1610), is based on the cost per kW-year of capacity (single cycle combustion turbine). This cost (value) is then adjusted for the QF's relative contribution to the utility's peak load, and a rate is developed that is forecast to compensate that type of QF for that capacity over the course of a typical year.

PGE's 2016 IRP provides charts depicting an approximation of the capacity contribution value for increments of wind and solar resources using an electric load carrying capability (ELCC) methodology.[5] Using this method, each additional increment of the same type of variable energy resource provides relatively less capacity value. For wind, PGE's avoided cost calculation uses the first penetration level, 100 MW, of Pacific NW wind in its avoided cost calculation, which is 18.59 percent. For solar, PGE uses the third level, 300 MW, because that reflects the level of operating and contracted-for solar at the time of the "snapshot" for the IRP. This results in a solar capacity contribution of 15.33 percent rather than the 28 percent contribution of the first 100 MW. Staff recommends that PGE provide more detailed documentation of its method of applying data inputs from the IRP to the avoided cost workpapers.

4. Integration charges

In this filing, PGE amended Schedule 201 to apply integration charges to solar QFs as well as wind QFs. Additionally, PGE updated the costs of integration based on the results of the Variable Energy Integration Study from the 2016 IRP. These updated costs are significantly lower than the wind integration charges currently in place as shown in Figure 1.

Figure 1.



Staff supports the use of the updated variable energy resource integration costs; however, Staff does not support the application of the same charge to both wind and solar QFs. Solar and wind have very different generation characteristics that should be incorporated into their respective charges, with solar integration generally being less costly than wind integration. Staff suggests that PGE conduct an analysis that

[5] PGE 2016 IRP, p. 127, providing the electric load carrying capability in increments of 100 MW for PNW Wind, Montana Wind, and Solar resources.

reasonably allocates the respective integration costs and file an amended proposal with the Commission.

5. Effective date

PGE submitted a Motion for Temporary Relief from its obligation to enter into standard contracts with QFs greater than 100 kW at the same time it made its August 18, 2017, updated avoided cost price filing. In accordance with this motion, PGE filed two versions of Schedule 201 each with a different effective date: one for use if the Commission granted the motion for temporary relief from entering into standard contracting and one for use if the Commission did not. If the Commission grants PGE's request for temporary relief from its obligation to contract for the period starting August 8, 2017 and ending on the effective date of its updated avoided costs, PGE asks that the effective date of its update be August 18, 2017(30 days after the updated cost filing). Alternatively, PGE asks that the effective date of its updated prices be August 8, 2017, the date the Commission acknowledged PGE's IRP. Staff does not support a retroactive effective date for PGE's updated avoided cost prices, nor PGE's request for temporary relief from its contracting obligation that PGE filed contemporaneously with its avoided cost price update.

Staff acknowledges that the prices proposed by PGE are less than the currently effective prices. However, Staff does not belief the difference is so great that the extraordinary relief asked for by PGE (temporary suspension of contracting starting August 8, 2017, or retroactive effective date) warrants departing from the Commission's traditional manner of implementing avoided cost price updates on a forward-looking basis only. Staff also does not think the difference warrants PGE's request for a suspension of its contracting obligation.

Staff recommends that any updated avoided cost prices resulting from a Commission decision on this filing become effective no sooner than September 18, 2017. Under OAR 860-029-0040(4)(a), utilities are required to file the post-IRP acknowledgment prices with an effective date 30 days after filing. Under OAR 860-029-0080(6), the prices are subject to suspension and investigation. The 30-day period between filing of avoided cost prices and the effective date of the prices provides opportunity for Staff and stakeholders to review the utility's filing and determine whether to seek suspension and investigation.

In this case, Staff does not recommend suspension, but does recommend that the Commission require PGE to make the Staff recommended changes to its proposed avoided cost prices discussed above in order to be consistent with the Commission's acknowledgment of PGE's 2016 IRP and the Commission's previous orders.[6] In order to allow time for PGE to make this compliance filing, Staff recommends that the effective date of new prices be two days after PGE submits the revised prices to Staff providing that this alternate effective date does not precede September 18, 2017.

Stakeholder comments
Comments filed by Falls Creek Hydro, L.P. (Falls Creek) on September 1, 2017, and the Renewable Energy Coalition, Northwest Intermountain Power Producers Coalition, and Community Renewable Energy Association (Joint Commenters) on September 7, 2017, are summarized below. Comments filed on September 7, 2017, by Strata Solar Development, LLC and by Borrego Solar Systems, Inc. were received as this staff report was being finalized and are not included below.

Falls Creek argues that PGE has not been negotiating in good faith in Falls Creek's efforts to obtain a schedule 201 standard contract with PGE.[7] Falls Creek outlines in comments the value that its facilities provide to the greater community.[8] Falls Creek argues that PGE's mistakes in the processes of its Schedule 201 standard contact application really represented delay tactics.[9] Finally, Falls Creek asserts that if its application is not approved based on avoided cost prices in effect at the time the request for a standard contract was made, its facility could be forced to shut down and the value provided by that facility to the community lost.[10] Falls Creek requests an effective date of September 18 for the application of updated costs, and requests Commission support for the resolution of issues in the development of a standard PPA with PGE.

Joint Commenters allege that QF developers have a reasonable expectation that new avoided cost rates would take effect in October or November; and that PGE is deliberately attempting to upset development schedules through accelerated avoided cost update requests.[11] Joint Commenters argue that PGE's request to make avoided cost updates retroactive is unprecedented.[12] They also note that PGE's motion does not comply with OAR 860-029-0040(4)(a); which states in relevant part that rates become effective "...30 days after filing."[13]

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[6] OAR860-029-0040(4)(a).
[7] Comments of Falls Creek Hydro L.P. at 2.
[8] Id. at 3-4.
[9] Id. at 5.
[10] Id. at 2.
[11] Renewable Energy Coalition and the Northwest Intermountain Power Producers Coalition and Community Renewable Energy Association's Joint Response to PGE's Schedule 201 Compliance Filing and Motion for Temporary Relief from Schedule 201 prices at 3.
[12] Id. at 4.
[13] Id. at 5.

Joint Commenters further argue that PGE's request for relief is not consistent with Commission rules and precedent valuing a settled business climate for QF facilities.[14] Asserting that PGE's actions to discourage QF development are duplicitous, Joint Commenters note that PGE strongly desires to acquire renewable energy before 2029, and that its real purpose in filing low avoided cost rates and a 2029 renewable energy deficiency period is to discourage competition from QFs for development of those renewable resources.[15] Joint Commenters argue that PGE has engaged in a series of stalling tactics with QFs attempting to complete contracts with PGE, and that accepting PGE's motion would encourage PGE's behavior.[16] Beyond a violation of rules, Joint Commenters argue that PGE's request for retroactive relief is inconsistent with state statute, which requires a filing of avoided forecasted prices.[17] Joint Commenters note that PGE itself has argued and the Commission ruled that avoided cost rates cannot be applied retroactively; and that broad utility regulatory standards support this proposition.[18] Going further, Joint Commenters assert that the retroactive relief requested by PGE violates the Due Process Clause of the U.S. and Oregon Constitutions.[19]

Next, Joint Commenters argue that there are serious substantive flaws with PGE's avoided cost update. Specifically, Joint Commenters argue that PGE has proposed inaccurate resource sufficiency periods, 2025 for nonrenewable resources and 2029 for renewable resources. Joint Commenters argue that PGE will certainly develop renewable resources before 2029, and that PGE's acknowledged capacity need is 2021.[20] Joint Commenters also argue that solar integration charges included in avoided costs are high, not supported by evidence, and that their inclusion in the avoided cost update is inconsistent with Commission order; which requires a separate filing and study.[21] Finally, Joint Commenters point out that that PGE's solar capacity contribution numbers are not consistent with its IRP filing; which shows solar capacity contributions of 25%; while the avoided cost filing puts those contributions at 15.3%.[22]

Staff's response to stakeholder comments

Staff agrees with Falls Creek that the effective date for the updated avoided cost prices should be no sooner than 30 days after filing. However, Staff recommends that the Commission allow the opportunity for PGE to make changes to its updated prices,

[14] Id. at 7-8.
[15] Id. at 9.
[16] Id. at 10.
[17] Id.
[18] Id. at 11.
[19] Id. at 14.
[20] Id. 19-20.
[21] Id. at 23.
[22] Id. at 26.

which may mean an effective date later than 30 days after the date PGE filed the prices. With respect to Falls Creek's request for Commission assistance in resolving issues with its acquisition of a PPA with PGE, Staff notes that these questions are more appropriately resolved in the docket opened for the complaint that Falls Creek has filed, Docket No. 1859.

Regarding Joint Commenters' concern that developers generally expected new avoided cost rates to take effect in October or November, and that a mid-September effective date will "upset those expectations," Staff points out that it is within the utility's discretion as to when to make a post-IRP acknowledgment filing so long as it is within 30 days of acknowledgment. The public meeting for Docket No. LC 66 has been known to be August 8, 2017, since March 2, 2017. Staff concludes that this is sufficient notice that PGE would make an avoided cost filing within 30 days of August 8, 2017.

Staff agrees with Joint Commenters' concerns about the nonrenewable deficiency period, and for the reasons explained above, supports a 2021 demarcation for PGE's nonrenewable deficiency period.

Staff does not support Joint Commenters' assertion that 2029 is an incorrect year for PGE's renewable deficiency. Even though the Commission has offered a window of time within which PGE may return with a different renewable resource acquisition strategy, it is clear that the Company's regulatory need for renewable resources begins in 2029.

Staff generally agrees with Joint Commenters' concerns about PGE's addition of a solar integration charge that is identical to the wind integration charge.

Conclusion

In summary, Staff sees significant issues with PGE's avoided cost filing. Rather than not allowing them to go into effect and exacerbating the significantly out-of-date prices in Schedule 201, Staff recommends that PGE be directed to recalculate its avoided costs by making the following changes:

- Change the nonrenewable deficiency period to 2021
- Remove the solar integration charge
- Correct anomalies in capacity payments for renewable on-peak prices

In addition, Staff recommends that PGE recalculate integration charges based on an allocation between wind and solar, building on the variable energy integration study results in the 2016 IRP.

Finally, Staff recommends that changes the Commission orders in this docket be combined with any changes ordered for agenda Item 2 on this September 12 public meeting as that item also addresses changes to PGE's Schedule 201.

PROPOSED COMMISSION MOTION:

Issue an order directing Portland General Electric (PGE) to file a modified Schedule 201 to be effective two days after filing, but no sooner than September 18, 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 359

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Teyent Gossa

July 16, 2019

Table of Contents

I. Introduction

Q. Please state your name and position with Portland General Electric (PGE).

A. My name is Teyent Gossa. My position at PGE is Manager, Trading Analytics and Bidding Strategy.

My qualifications are provided at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of mt testimony is to respond to the positions the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) and the Alliance of Western Energy Consumers (AWEC) put forward regarding PGE's forecast for 2020 Western Energy Imbalance Market (EIM) benefits.

Q. Please summarize your review of parties' positions.

A. Parties propose higher EIM benefits by applying forecast methods that are incomplete, ignoring the ratemaking paradigm of the AUT and PCAM, or propose other changes that are opportunistic in nature.

Q. What is your recommendation regarding the specific issues identified below?

A. I recommend the Commission reject OPUC Staff's, and AWEC's proposed adjustments.

Q. How is the remainder of your testimony organized?

A. After this introduction, I have three sections:

- Section II: Parties' Proposed EIM Adjustments
- Section III: Summary and Conclusion
- Section IV; Qualifications

II. Parties' Proposed Western EIM Adjustments

Q. Please summarize the EIM forecast PGE put forth in its Initial Filing.

A. In the initial filing for 2020 NVPC, PGE proposed using actual 2018 sub-hourly dispatch savings results adjusted for two years of inflation using MONET's 2.5% standard rate. Additionally, PGE proposed to include 50% of actual 2018 hydro greenhouse gas (GHG) awards escalated by 7.5% per year (i.e., (2.5% for inflation and 5.0% for real growth). The reduction of 2018 actuals by 50% was to recognize the late 2018 change to the method used for awarding GHG revenues. Finally, PGE reduced this gross revenue forecast by 2018 actual grid management charges, also inflated by MONET's 2.5% standard inflation rate.

Q. What do you believe is a reasonable expectation for the net variable power cost impacts from EIM?

A. I anticipate that EIM sub-hourly dispatch will reduce PGE's net variable power costs by 1% to 2%. More specifically, this is our expectation of the impact of PGE's participation in the EIM on the variable costs that MONET forecasts. This includes (1) MONET's balancing purchases and sales and (2) MONET's forecast of variable costs from resources that are considered "participating resources" in the EIM.

It is important to note that in our initial filing, we also put forward a forecast for NVPC savings that can result from PGE receiving GHG awards in the EIM. This is a benefit that is separate from PGE's positions on sub-hourly dispatch savings, and we are careful to not comingle their impacts. We believe parties should do the same, and I discuss the importance of this distinction later in my reply testimony.

Q. Why do you believe 1% to 2% is a reasonable expectation?

A. This was a question posed by CUB during discovery. Third-party expertise[1] has consistently indicated to PGE that 1% to 2% of an organization's fuel budget is a reasonable expectation for savings from an EIM. PGE's own production cost modeling supports the conclusion from the third-party, and PacifiCorp has reported results in this range.

Q. Do parties believe PGE has established a reasonable forecast of EIM benefits?

A. No, they do not. Instead, they propose higher EIM benefits by applying forecast methods that are incomplete, ignore the ratemaking paradigm of the AUT and PCAM, or propose other changes that are opportunistic in nature.

Q. Please summarize Parties' positions regarding EIM Benefits.

A. Staff argues that, based on three months of actual EIM benefits in the beginning of 2019, PGE's EIM benefits are increasing and therefore PGE's forecast for 2020 is too low.[2] As such, Staff recommends using the most recent 12 months of data available to update EIM sub-hourly dispatch benefits.

AWEC argues that, based on their analysis, PGE has incurred "significant" losses in the EIM and that these losses should be removed from the 2018 data used to develop PGE's 2020 forecast.[3] Additionally, both parties argue that PGE's GHG award forecast is too low and that a reduction of the 2018 revenues used to develop the 2020 forecast, based on a reduction in award quantities, over estimates the effect of market changes of GHG award benefits. AWEC argues for the use of the most recent 12 months of data to forecast GHG award benefits, while Staff proposes a higher escalation factor, than PGE's 7.5%, be used.

[1] Exhibit 401 and Confidential Exhibit 402 include PGE's Response to CUB Data Request No. 009, which provides this information.
[2] Staff Exhibit 300, page 7.
[3] AWEC Exhibit 200, page 15.

Q. Do you agree with parties' positions?

A. No, I do not.

Q. How is the remainder of your reply to parties EIM positions organized?

A. I first address AWEC's method of removing EIM losses and explain why their method is inconsistent with the CAISO market design. I then address the fact that by only accepting EIM gains, AWEC's method is opportunistic in nature. Next, I address our concerns with Staff's proposal to use the most recent 12 months of actuals. Finally, I discuss PGE's hydro GHG forecast and why I believe it is reasonable.

A. AWEC's Method is Not Consistent with CAISO Market Design

Q. AWEC recommends that loss-generating transactions from the fifteen-minute market (FMM) and five-minute market (i.e., also known as Real Time Dispatch or RTD) should be removed, because PGE will "learn" and reduce the losses. What is your response?

A. AWEC assumes that CAISO's market engine results always generate revenues for PGE that, at least, cover cost in every market interval (i.e., 5-minute and 15-minute). Using AWEC's logic, any losses are the result of PGE "mistakes" that can be improved as the Company gains more EIM experience.

Q. Is AWEC's assumption about the CAISO market engine correct?

A. No. The CAISO does not guarantee a gain in every market interval. CAISO recognizes that a resource may not be made whole in every market interval, and as part of its settlement paradigm, scheduling coordinators can receive revenue in the form of Bid Cost Recovery (BCR) that provides make-whole payments when a resource's revenues do not cover its costs for the <u>entire trading day</u>. In other words, when calculating whether a BCR make-whole payment is due, gains from one hour offset losses from other hours. If the net result for the day is a loss, the resource is eligible for a make-whole payment.

Q. Please describe Bid Cost Recovery (BCR) in more detail.

A. CAISO requires energy bids to be submitted as three components: (1) a bid for start-up cost, (2) a bid for operating at a minimum output level (i.e., minimum load), and (3) a series of bids for energy output above the minimum operating level (i.e., incremental energy). This design allows the market to efficiently consider incremental energy costs once the market issues unit commitment instructions to a generator. However, CAISO recognizes that revenues in the real-time market may not cover the total cost of a resource (i.e., start-up, min load, and incremental energy) for a number of reasons. These reasons include:

- **Lumpy unit commitment**: There are times where the CAISO market engine must choose between relatively higher energy prices or additional unit commitment, which will lower incremental energy prices. The market will select the outcome that lowers <u>total market costs</u> <u>for the market footprint</u>, and this can create losses for individual generators.
- **Ramping Forecast Error**: The real-time market does not forecast loads perfectly. This can lead to prices being inconsistent with a generator's bids until the generator can ramp in response to the dispatch.
- **Unit Commitment Forecast Error**: The real-time market optimization occurs over several intervals that look ahead, and if the actual results are different from forecast,

the unit commitment issued by the market may also be wrong, and the resource may be left in an operating state that is no longer economical.[4]

Q. Is BCR applied to every fifteen-minute market and real-time dispatch interval?

A. No. It is applied on a daily basis to each participating resource. That is, there has to be a shortfall over the entire day in the real-time market. If market revenues do not cover costs when summed over the day, CAISO will issue a make-whole payment subject to the BCR settlement rules.

Q. Did AWEC account for this market design principle in its proposal?

A. No.

Q. What changes would PGE make to AWEC's proposal?

A. First, I suggest implementing the concept of Bid Cost Recovery to AWEC's analysis. That is, only count losses when there is a shortfall over the entire day. This will reduce AWEC's proposal by $4.9 million (i.e., $3.1 million for thermal resources and $1.8 million for hydro resources).

Second, parties cannot add back losses without also foregoing the actual Bid Cost Recovery dollars that PGE included in its initial measurement of EIM benefit. This reduces AWEC's proposal by an additional $1.5 million.

Third, AWEC erroneously argues that plant trips cannot impact FMM and RTD outcomes. Plant trips <u>can</u> create losses in the FMM and RTD, specifically because of the unit commitment forecast error described previously. The real-time market optimization makes commitment and dispatch decisions that are binding prior to a plant trip. This can lead to

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[4] For example, a prior market optimization run may issue a unit commitment instruction to turn on a gas resource's duct burner. Once committed, the duct burner may have a minimum operating time (i.e., minimum on time) that requires the plant to operate in the duct burner operating state even in subsequent market optimizations result in different pricing.

losses, and I adjust for this in our proposed changes. This will further reduce AWEC's proposal by $0.5 million.

Table 1 displays the outcome of those changes. PGE's calculation of 2018 EIM benefit is $6.3 million. AWEC proposed increasing the EIM benefit amount to $15.1 million. With PGE's first set of revisions, the 2018 benefit would be $8.2 million.

Table 1

	Amount	Cumulative Amount	Rationale
1	$6.3 million	-	PGE's 2018 Actuals from Initial Filing
2	+ $6.6 million	$12.8 million	AWEC adds back total thermal loss for FMM and RTD
3	+ $2.2 million	$15.0 million	AWEC adds back total hydro loss for FMM and RTD
4	<$3.1 million>	$12.0 million	Apply BCR principle of loss at a daily level to combined FMM and RTD – applied to thermal, this reduces loss from $6.6 million to $3.5 million
5	<$1.8 million>	$10.1 million	Apply BCR principle of loss at a daily level to combined FMM and RTD – applied to hydro, this reduces loss from $2.2 million to $0.4 million
6	<$1.5 million>	$8.6 million	Remove all BCR; Parties do not receive BCR if they seek to add back losses
7	<$0.5 million>	$8.2 million	Outages created FMM and RTD losses. Examples include: Carty outage on July 18th results in a $350k loss. Coyote outage on April 23rd results in a $49k loss. Boardman outage on August 5th results in a $35k loss. Coyote outage August 21st results in $19k loss.

*Values may not sum due to rounding

Q. What accounts for the difference between $8.2 million and $6.3 million?

A. The key difference is the result of PGE's gas and power trading tied to Carty and Coyote Springs. As AWEC noted in AWEC Exhibit 100, PGE can seek to lower power costs by selling gas instead of producing power at Carty and Coyote. In the EIM, PGE can incur "losses" when its energy bids reflect a Stanfield (i.e., higher) fuel price, because the EIM power we purchase remains more expensive than the cost of power production based on AECO (i.e., lower) fuel prices. However, in these instances, PGE's gas resale should offset the EIM "loss".

Q. What are the net daily EIM losses associated with Coyote and Carty?

A. The net daily EIM losses for Coyote and Carty are $1.4 million.

Q. Does PGE support adding the daily EIM losses to the EIM benefit forecast?

A. No. Adding back the EIM losses would be double counting them. As AWEC identifies in Section III of AWEC Exhibit 100, PGE captures the financial benefit of this trading activity in MONET by dispatching the Carty and Coyote Springs plants at AECO (i.e., lower) prices, not Stanfield (i.e., higher) prices.

B. AWEC's Method Opportunistically Seeks Gains Without Accepting Losses

Q. Do you have other concerns with AWEC's proposal?

A. Yes. While not entirely clear in testimony, AWEC appears to propose that MONET is the appropriate tool to account for the cost impacts associated with the real-time operations that lead to PGE not bidding its marginal cost in all hours. As I will demonstrate below, AWEC is opportunistically asking for many of the "gains" from the EIM without accepting the associated "losses".

Q. Are there reasons that PGE could incur losses in the EIM, but ultimately reduce net variable power costs?

A. Yes.

Q. Please describe these reasons.

A. PGE's operational objective is to reliably serve load in a manner that minimizes its net variable power costs across time (i.e., term markets, pre-schedule markets, hourly bilateral trading, EIM, etc.) and products (i.e., natural gas, electric power, etc.). In real time, Power Operations monitors PGE's load (both customer and Balancing Authority Area) and generating resources (hydro, thermal, and wind) in order to adjust procurement and dispatch activity to maintain reliability on PGE's system and to economically serve customer load.

As part of PGE's overall effort to maintain reliability on PGE's system and/or minimize NVPC, PGE may submit adjusted energy bids in the EIM that are different from the price produced by a strict operating cost assessment for the relevant trading hour. These bid changes may reflect relevant trading or operational variables such as:

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

This information was previously provided in PGE's Response to AWEC Data Request No. 035 and included here as PGE Exhibits 403 and 404.

Q. What is the result when PGE makes these types of bid adjustments in the EIM?

A. When these types of bid adjustments are made, the EIM bid is not directly the operating cost for the trading hour, but it is PGE's best estimate of the bid that can ultimately minimize PGE's NVPC in total over the course of the operating year. During these events, EIM losses can occur.

Q. What does AWEC think of these reasons?

A. AWEC believes that there is double-counting if the losses are not removed from the EIM benefit value.

Q. Do you agree with AWEC's position?

A. No. AWEC's proposal seeks to remove the losses, but keep the gains associated with PGE's efforts to respond appropriately and economically to the contingencies PGE manages in its real-time operations.

Q. Can you provide an example?

A. Yes. The most prevalent, and financially impactful, example for EIM benefits is PGE's hydro resources that are participating resources in the EIM. These resources effectively have daily energy limits. That is, on a daily basis, PGE manages a "bucket" of MWh, seeking to allocate the energy across the day that (1) reliably meets load and (2) minimizes net variable power costs. With PGE's participation in the EIM, PGE can continue to reliably serve load and also secure additional power cost reductions.

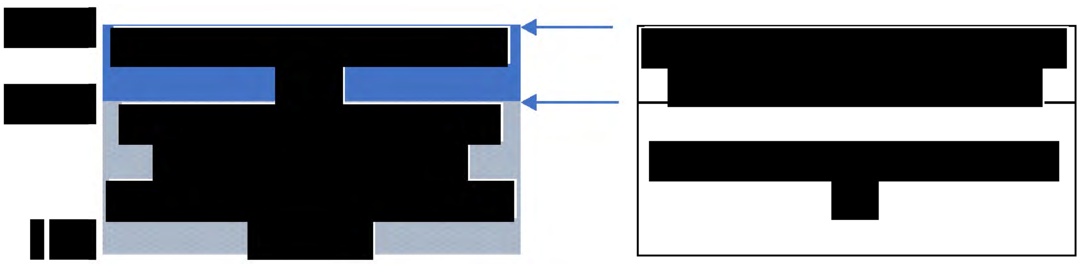
Q. Please explain how PGE secures the additional power cost reductions.

A. [redacted]

[redacted]

[redacted]

Figure 1



Q. Does PGE take a risk when it does this?

A. Yes, a financial risk. [redacted]

Q. How do losses show up in the EIM benefit that PGE reports?

A. [redacted]

Q. How does MONET capture this trading activity?

A. Subject to ancillary service requirements and operating constraints, MONET shapes the hydro energy into the hours that are expected to be the most economical for customers. To remain in load/resource balance, MONET assumes all purchases and sales are made at Mid-C. That is, MONET treats hydro in the manner AWEC suggests. However, if AWEC seeks to avoid EIM losses associated with PGE's hydro resources, PGE can eliminate this financial risk-taking activity from the EIM benefit and MONET will capture the operational objectives AWEC recommends MONET manage.

Q. What would be the impact on the EIM benefit forecast?

A. Under this scenario, EIM benefits would be reduced. If no adjustment is made to AWEC's proposal, the benefit would reduce by $6.5 million. With PGE's adjustments to AWEC's proposal (listed above in Table 1), the benefit would be reduced by $4.7 million.[5]

C. Staff's Proposal Contradicts the AUT/PCAM Construct

Q. Staff recommends that PGE trend actuals to forecast 2020 benefits. Do you agree with Staff's recommendation?

A. No. Staff's trend of actuals would use market conditions that are not expected conditions going forward. I will address this in more detail below.

Q. Do you have other concerns with Staff's proposal?

A. Yes. No matter the intention, Staff mistakenly confuses PGE's proposal for EIM benefits from sub-hourly dispatch savings and the measurement of actuals against the proposal. In

[5] Under our calculation, the gross gain to be removed would be approximately $4.7 million, minus a loss of $0.4 million equals the $4.3 million net benefit. Under AWEC's calculation the gross gain to be removed would be approximately $6.5 million, minus a loss of $2.2 equals a $4.3 million net benefit.

PGE Exhibit 100, we clearly explained the distinction between sub-hourly dispatch savings and GHG benefits. Furthermore, PGE acknowledged that GHG benefits were not included in previous forecasts (and explained the reasons for previously excluding GHG benefits). Staff testimony ignores these explanations and builds visuals that exaggerate the differences between PGE's benefit forecasts and the actuals.

Q. How would you correct the presentation made by Staff?

A. In several ways. To aid in our summary, I will begin with Staff's Figure 1 (as provided in Staff Exhibit 300) and make sequential adjustments. In the modified Figure 2 below, the "PGE Initial Forecast" and "Actual Benefit" lines remain unchanged.

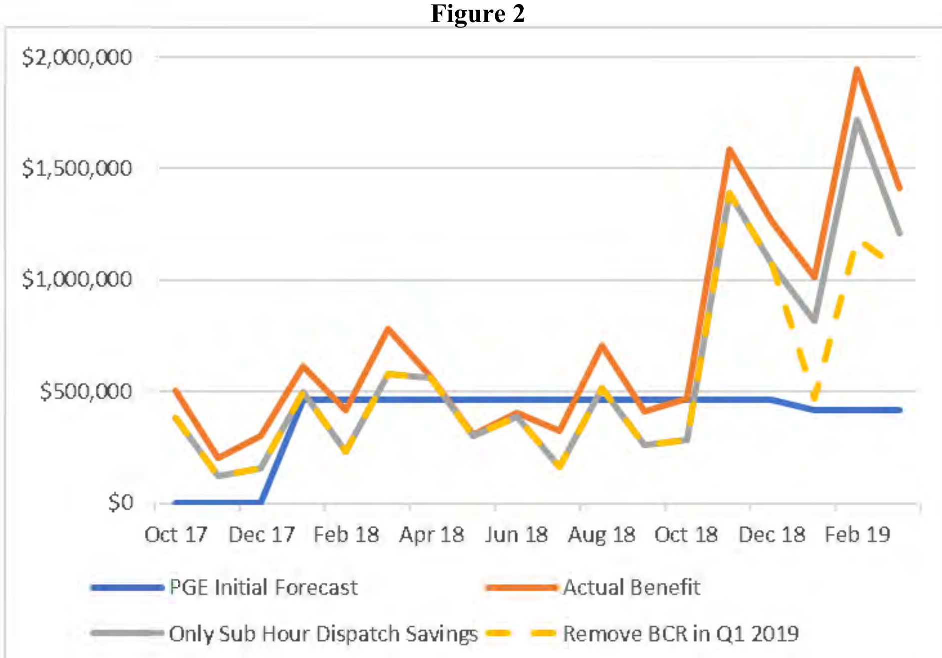
PGE's first change is to remove the GHG benefit from this chart. As discussed in our initial testimony, PGE did not forecast GHG benefit in its 2018 and 2019 forecasts. PGE forecasted sub-hourly benefits less settlement charges. Therefore, the appropriate comparison of forecast to actuals is one without GHG. PGE has proposed to forecast the GHG benefit separately.

PGE's second change would be to remove the majority of BCR in Q1 2019, since the goal is to conduct a measure of forecast accuracy and identify structural changes in PGE's benefit that will be persistent. This second change is necessary because CAISO implemented a software change late in December 2018 that changed unit commitment logic. This materially impacted PGE, because many of PGE's resources are modeled as Multi-Stage Generators in the market.[6] When CAISO made its software change, it made it likely that the configuration in which PGE base scheduled would be the configuration for which CAISO issued unit

[6] Multi-Stage Generators mean that CAISO has more than one "configuration" that the market can select for its unit commitment. The simplest example is a duct burner on a combined cycle plant like Carty. Carty operating with its duct burner is a different configuration than Carty operating at baseload.

commitments, even if it was not economic relative to the EIM pricing. Therefore, PGE collected a high level of BCR during the months of January and February and the first part of March, because EIM prices did not compensate PGE for its minimum load costs. As this issue has now largely been resolved, we do not expect that level of BCR on an ongoing basis. Confidential Exhibit 405 provides the CAISO description of the impact of its software change on BCR.

Figure 2



Q. Do you have other observations about Staff Figure 1?

A. Yes. In February 2019, PGE incurred large losses relative to the AUT power cost forecast. As I will discuss in more detail below, PGE's participation in the EIM effectively allowed us to "lose less" during this time. To forecast EIM benefits without acknowledging the net variable power cost losses is inconsistent with PGE's AUT/PCAM paradigm.

Q. Please describe in more detail what you mean by "lose less".

A. At the end of Q1 2019, PGE's PCAM analysis showed PGE nearly $13 million above its net variable power cost baseline. That is, PGE's power costs were above the MONET forecast used in rates at that time. A material driver of that outcome was the month of February when unexpected cold weather pushed loads considerably above the AUT forecast and hydro flow much below normal for the region. These factors caused Mid-C prices to clear significantly higher than the values forecast in the AUT. As shown in Staff's original Figure 1, February 2019 is PGE's highest reported EIM benefit to-date. However, $1.2 million of the $1.6 million in sub-hourly dispatch savings (net of grid management charges) is derived from PGE's hydro resources, which used the trading tactics I described above. During this month, PGE was purchasing power in the EIM at lower prices than the prices offered in the real-time bilateral market. However, they were not gains if viewed from the normalized conditions modeled in MONET. For example, in the fifteen-minute market, PGE was purchasing energy that on average ranged from approximately $45 to $53 depending on the resource. PGE avoided purchases that we estimate to range from approximately $65 to $69 on average. Relative to the costs we forecast in MONET, the EIM trading activity we benefited from in February 2019 effectively allowed us to "lose less". When PGE made the final AUT filing in November 2018, the February Mid-C price was forecasted to be $37.60 for On-Peak hours and $26.90 for Off-Peak hours. In fact, PGE's preliminary PCAM assessment for the month of February showed that February power costs, after standard PCAM adjustments, were $24 million above the costs established by PGE's final 2019 NVPC forecast.

Q. Is PGE proposing to use 2019 benefits to forecast 2020?

A. No. To-date, 2019 would not be representative of a normalized estimate that is appropriate to use in the MONET NVPC forecast.

Q. Why is PGE proposing to use 2018 benefits if November and December also had higher benefits?

A. As we discussed in our initial testimony, the 2018 benefits for the calendar year from sub-hourly dispatch savings are similar to normalized benefits that we produced from production cost modeling, even though November and December 2018 represent months where a considerable portion of the benefit is derived from employing our hydro trading tactics in a market well-above the Mid-C prices used in the AUT. Furthermore, if measured against our initial filing, PGE's forecast for sub-hourly dispatch savings, net of grid management charges, would be approximately 1.8% of the costs in PGE's MONET forecast that are variable and influenced by PGE's activity in the EIM. This is within the band of reasonableness that we review and consider when establishing forecasts for future years. Therefore, after applying the adjustments described above to Staff's Figure 1, PGE's actual 2018 sub-hourly dispatch benefits are very much in-line with our previous forecast for most months of 2018 and when escalated to 2020 are close to 2% of MONET's variable power cost forecast for 2020.

D. GHG Forecast is Reasonable

Q. Staff and AWEC believe that PGE ignores the fundamentals of supply and demand. Specifically, that prices will rise when supply of zero cost GHG offers is lower. How do you respond?

A. Staff and AWEC focus too narrowly on the market rule change that PGE describes in its initial testimony and seek to leave the impression that PGE has focused too heavily on the change in its quantity. They target the change in market rules as the only change impacting the EIM

GHG market in 2020. However, there are other changes that will likely increase the supply of zero cost GHG offered in the market and place downward pressure on GHG prices.

Q. What other changes will impact the EIM GHG market in 2020?

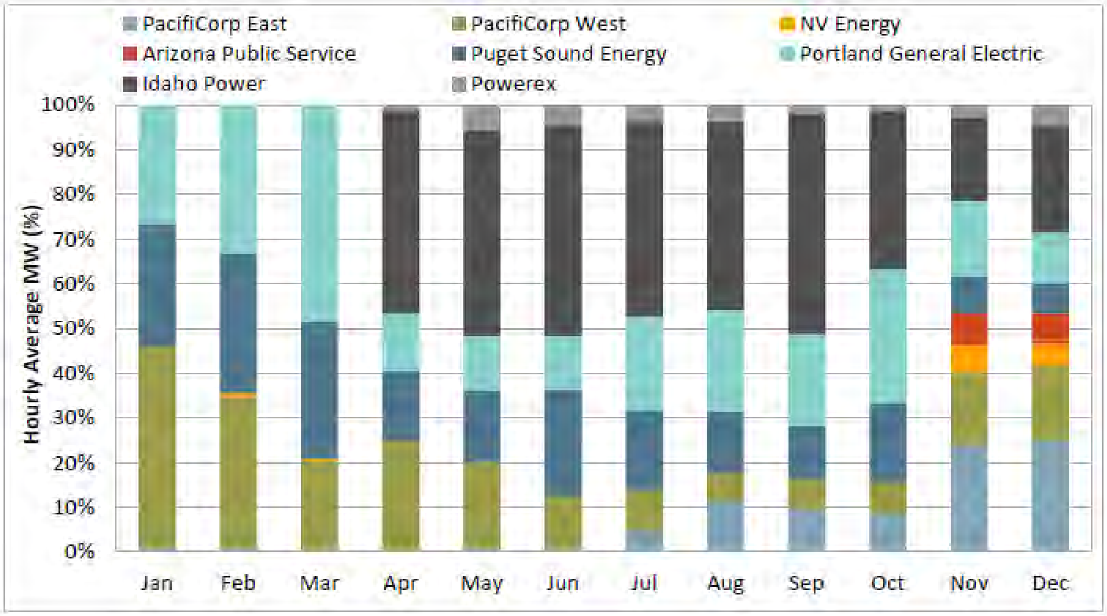
A. First, Seattle City Light will enter the market in April 2020, and if Seattle City Light elects to offer GHG in the EIM, they will be offering zero cost hydro. Second, current participants like Powerex may elect to offer GHG into the market in 2020 at higher levels. To date, Powerex has primarily imported from the EIM, and therefore, they are less likely to be recipients of GHG awards. However, Powerex has led a successful effort to revise market power mitigation rules that will increase their ability to offer exports without the adverse economic consequences that they experienced during 2018.[7] It is possible that the revised rules will lead to Powerex also seeking to sell into the EIM more often.

Q. Have new entrants with large amounts of zero cost GHG resources entered the market previously?

A. Yes. As part of the Department of Market Monitoring's (DMM) Annual Report,[8] DMM reports on the percentage of GHG MW awards by area. In April 2018, Idaho Power and Powerex joined the EIM. In particular, Idaho Power claimed nearly 50% of the market when it entered EIM in April (see the solid black bar in Figure 3 below). Consequently, PGE's market share and GHG MW awards were reduced considerably.

[7] CAISO's Local Market Power Mitigation Initiative is available at http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalMarketPowerMitigationEnhancements2018.aspx.
[8] See http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf at Page 129.

Figure 3 Percentage of greenhouse gas megawatts by area (2018)



Source: DMM 2018 Annual Report

Q. In its testimony, Staff presents Figure 6,[9] arguing that a 5% escalation tied to the administrative increase of GHG allowance floor prices is too low. How do you respond?

A. In its Figure 6, Staff escalates a 2012 nominal value by 5% each year showing that a 5% growth rate would only result in a value of $14.20 when the average 2019 allowance price was $16.59. First, Staff's presentation is not correct. In its method, PGE escalates by a total of 7.5% (2.5% for inflation and 5.0% for real growth). If Staff fully applied PGE's method to their illustration, they would escalate the 2012 nominal value in Staff's figure ($10.09) by 7.5% for the 7 years, resulting in $16.74, which is $0.15 higher than the $16.59 value, not $2.39 lower as presented in Staff's figure. Second, the GHG price awarded to market entities is effectively the daily GHG allowance price multiplied by the implied emission factor from the marginal GHG offer that clears the market. As mentioned previously, more hydro or other non-emitting resources are likely to be offered into the GHG market in 2020, which will place

[9] Staff Exhibit 300, page 11.

downward pressure on the clearing price. If a zero-cost offer is the clearing GHG MW award, the GHG price will be $0/MWh (i.e., non-emitting resources cannot submit a bid greater than $0/MWh). In other words, the allowance price could be above the administrative floor, and GHG award revenue could be lower than anticipated if large amounts of hydro supply (or other renewables) frequently set the price.

Q. Please summarize your proposal for GHG revenue derived from the EIM in 2020.

A. I propose no change to our initial forecast. The change in market rules in late 2018 is only one factor expected to impact the EIM GHG market in 2020. As more hydro or other non-emitting resources are likely to be offered into the GHG market in 2020, there is likely to be a greater supply in the market, which will place downward pressure on the clearing price.

III. Summary and Conclusion

Q. In closing, please summarize your proposals regarding the issues identified by parties.

A. I recommend the Commission reject the parties' positions regarding the forecast of 2020 EIM benefits. The parties propose higher EIM benefits by applying forecast methods that are incomplete, ignoring the ratemaking paradigm of the AUT and PCAM, or propose other changes that are opportunistic in nature.

Q. Does this conclude your testimony?

A. Yes.

IV. Qualifications

Q. Ms. Gossa, please describe your qualifications.

A. I received a Bachelor of Science degree in Chemistry from Portland State University in 1997. I have been employed at PGE since 1998 in a variety of positions including: Load Research & Load Forecasting Analyst, Information Technology (IT) Business Analyst, IT Developer, IT Project Manager, and Structuring and Origination Analyst. I helped lead the implementation of the EIM Bidding and Settlement system and processes and am currently Manager of Trading Analytics and Bidding Strategy. The Trading Analytics and Bidding Strategy group works closely with energy traders, reviewing regional market fundamentals and risks and we set the bidding strategy for the EIM market.

List of Exhibits

PGE Exhibit	Description
401	PGE's Response to CUB Data Request No. 009
402C	PGE's Confidential Response to CUB Data Request No. 009
403C	PGE's Confidential Response to AWEC Data Request No. 035
404	PGE's Response to AWEC Data Request No. 035
405C	CAISO description of the impact of its software change on BCR

June 21, 2019

TO: William Gehrke
Oregon Citizens' Utility Board

FROM: Jay Tinker
Directory, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE Response to CUB Data Request No. 009
Dated June 7, 2019

Request:

Refer to UE 359/PGE/100/Page 11/ Lines 11-12. Please provide a narrative explanation of why the Company assumes that 1 to 2% is a reasonable expectation of net variable power cost impacts from EIM.

Response:

There are many reasons for PGE's expectation. Three examples include:

1. Third Party Expertise: Power Costs, Inc. (PCI), a provider of software solutions for energy supply and trading organizations, informs its clients to estimate EIM savings that will be approximately 1 to 2 percent of an organization's fuel budget. Note that PGE's fuel budget is a subset of its net variable power costs. Attachment 009-A shows the PCI estimation under a slide titled "Lessons Learned".
2. Production Cost Modeling: In PGE's initial study of EIM participation, PGE estimated an approximate 1.1% impact on business-as-usual generation costs. This result is available in the study titled, "PGE EIM Comparative Study: Economic Analysis Report". The study was submitted in OPUC Docket No. LC56. In the study, business-as-usual generation costs were modeled to be $318.5 million, and EIM savings were estimated to be $3.5 million, with the inclusion of sub-hourly dispatch savings from the impacts of flexible reserve sharing.
3. Other Utility Experience: In its Transition Adjustment Mechanism (TAM) filing, PacifiCorp reported benefits that ranged between 1 to 2 percent of its net variable power cost. For example, refer to OPUC Docket No. 323, PacifiCorp Exhibit No. 100, Witness Wilding at page 25. In Table 3, PacifiCorp reported its 2017 EIM-Related Benefits to be $21.6 million (Total Company). In Exhibit No. 101, its "Total NPC Net of Adjustments" is reported to be $1,536,055,148. The reported EIM benefit of $21.6 million is 1.4% of the reported net power cost.

Attachment 009-A is protected information subject to Protective Order No. 19-112.

UE 359

Attachment 009-A

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

PCI EIM Savings Estimation

Exhibit 402C

Protected Information Subject to Protective Order 19-112

Exhibit 403C

Protected Information Subject to Protective Order 19-112

June 20, 2019

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

FROM: Jay Tinker
Director, Rates & Regulatory Affairs

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

Request:

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

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

Response:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Oct

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

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

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

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

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

UE 359

Attachment 035-A

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

EIM Dispatch Data

UE 359

Attachment 035-B

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

Source Data for Work Sheet "Power Cost Unit Summary" – PGE General Ledger Data

UE 359

Attachment 035-C

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

Source Data for Work Sheet "Power Cost Unit Summary" – PGE General Ledger Data Query

UE 359

Attachment 035-D

Protected and Subject to Protective Order No. 19-112

Provided in Electronic Format Only

PGE Hydro Benefit Differences Between
Attachment 035-A and "Power Cost Unit Summary"
Work Sheet

Exhibit 405C

Protected Information Subject to Protective Order 19-112

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 359

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Robert Macfarlane

July 16, 2019

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Robert Macfarlane. I am a Regulatory Consultant in the Pricing and Tariffs Department. My qualifications are provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to AWEC's proposal to exclude short-term direct access load from the forecasted net variable power cost (NVPC) calculations.

Q. Please summarize your response.

A. AWEC's proposal is unnecessary, impractical considering the timing of the November opt out window, and inconsistent with the February balance-of-year opt out window. Any material differences in NVPC due to the loads included in the November opt outs is either refunded or charged to customers as directed in PGE's Schedule 128 and has been since Schedule 128 first became effective in January 2007.

II. Short-Term Direct Access Loads

Q. During the November short-term opt out window, customers may choose direct access. Do customers have options other than direct access?

A. Yes, customers may choose direct access or PGE's daily price option. Both options are not considered cost of service (COS) and include transition adjustments as provided in PGE's Schedule 128.

Q. How does PGE treat short-term opt out loads?

A. PGE's load forecast does not include any non-COS elections for the purpose of setting NVPC in the AUT, or in general rate cases, as the short-term opt out window has not yet occurred when PGE's load forecast is finalized.

Q. Does this practice create a variance in the forecasted and actual loads?

A. Yes, to the extent customers choose a non-COS option during the short-term opt out window, there is a variance in the NVPC load forecast.

Q. How does PGE adjust for this variance?

A. PGE makes an adjustment to credit or charge eligible customers due to participants choosing to opt out of COS during the short-term opt out window under the Schedule 128 true up provision, "Large Nonresidential Load Shift True-up." The purpose is to reconcile any material variance in net variable power costs and either refund or charge COS customers for the difference. The materiality threshold is $240,000 for the November election window. The language from Schedule 128 is below.

> For the November window, the Company will compute the Load Shift True-Up as the difference between the market prices used to establish the Schedule 128 Transition Adjustment and the average of the corresponding projected market prices during the first full week in December times the load leaving Cost of Service pricing. For the Balance of Year Transition Adjustment windows, the Company will compute the True-Up as the difference between the market prices used to establish the Schedule 128 Transition

> Adjustments and the corresponding projected market prices during the first full week after the close of the window times the amount of load leaving Cost of Service pricing. For the November election window, the Company will file for a deferral after the close of the window if the True-Up is greater than $240,000. The filing threshold for each of the quarterly windows will be $60,000.

Given this true up mechanism, any material difference due to short term opt out loads is already accounted for under the current schedule provisions. PGE Exhibit 501 provides the Large Nonresidential Load Shift True-Up calculation related to the November 2017 short-term opt out window.

Q. When did Schedule 128 originate?

A. Schedule 128 first became effective in January 2007.

Q. Was the "Large Nonresidential Load Shift True-up" included in the first effective version?

A. Yes. ICNU, AWEC's predecessor, was a party to a stipulation in UE 180, approved in Commission Order No. 06-528, that modified PGE's proposal for the "Large Nonresidential Load Shift True-up" to allocate any load shift true-up amounts to all direct access eligible Large Nonresidential customers including both COS and non-COS customers. PGE's initial proposal in UE 180 was to allocate any load shift true-up amount to only participating customers receiving the Schedule 128 transition adjustment.

Q. Is AWEC's proposal practical?

A. No. First, the window occurs after the AUT is finalized. The short-term opt out window starts on November 15 and is open for five business days. The AUT is finalized on November 15. On a practical level, it would be impossible for PGE to incorporate the results of the window into the AUT.

Second, an additional balance of year window occurs in February for service beginning April 1. That window occurs well after the AUT is finalized. It would be impractical and inconsistent to exclude the loads from the November window and include the loads from the February window.

Due to these timing limitations, the True Up Mechanism, as designed in UE 180, is the most practical way to account for short-term opt outs in the AUT.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
501	Large Nonresidential Load Shift True-Up Calculation

2018 Schedule 128 - Annual November Election Window Load True-Up Calculation

Projected 2018 Schedule 128 Transition Adjustment Load at the Busbar (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-Peak	12,774	12,244	12,993	12,551	13,570	13,161	14,916	14,765	13,199	13,666	13,360	13,364	160,562
Off-Peak	7,043	6,500	6,849	6,433	6,871	6,704	7,452	7,357	6,572	7,020	6,946	7,160	82,906
Total	**19,817**	**18,744**	**19,842**	**18,985**	**20,441**	**19,864**	**22,368**	**22,122**	**19,771**	**20,686**	**20,305**	**20,524**	**243,468**

Open Enrollment Window Curve (November 10, 2017) and Value

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-Peak ($/MWh)	$30.00	$26.50	$18.75	$17.00	$16.75	$18.00	$28.25	$32.00	$28.25	$25.25	$26.00	$31.25	$24.83
Off-Peak ($/MWh)	$24.75	$21.50	$14.50	$10.25	$6.00	$6.25	$19.00	$22.25	$22.75	$21.75	$22.00	$25.00	$18.00
Value													
On-Peak	$383,212	$324,476	$243,613	$213,371	$227,290	$236,893	$421,378	$472,475	$372,874	$345,056	$347,352	$417,630	$4,005,619
Off-Peak	$174,311	$139,743	$99,315	$65,941	$41,226	$41,899	$141,590	$163,693	$149,519	$152,683	$152,803	$178,991	$1,501,715
Total	**$557,522**	**$464,219**	**$342,928**	**$279,312**	**$268,516**	**$278,791**	**$562,968**	**$636,168**	**$522,393**	**$497,739**	**$500,156**	**$596,621**	**$5,507,334**

Post Enrollment Window Curve (5-day average, Dec 4 - Dec 8, 2017) and Value

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-Peak ($/MWh)	$27.58	$24.95	$19.30	$17.10	$17.00	$18.55	$28.50	$32.25	$28.50	$23.95	$24.90	$30.20	$24.40
Off-Peak ($/MWh)	$22.40	$20.55	$15.00	$11.55	$6.70	$6.85	$17.25	$23.60	$23.60	$21.15	$21.50	$24.80	$17.91
Value													
On-Peak	$352,299	$305,497	$250,759	$214,626	$230,682	$244,131	$425,107	$476,166	$376,174	$327,291	$332,657	$403,598	$3,938,986
Off-Peak	$157,760	$133,569	$102,740	$74,308	$46,036	$45,921	$128,549	$173,625	$155,106	$148,471	$149,331	$177,559	$1,492,974
Total	**$510,059**	**$439,065**	**$353,499**	**$288,934**	**$276,718**	**$290,052**	**$553,656**	**$649,791**	**$531,279**	**$475,762**	**$481,987**	**$581,157**	**$5,431,960**

Delta in Value (Open Enrollment vs. Post Enrollment)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
On-Peak	$30,912	$18,979	($7,146)	($1,255)	($3,392)	($7,238)	($3,729)	($3,691)	($3,300)	$17,765	$14,696	$14,032	$66,633
Off-Peak	$16,551	$6,175	($3,425)	($8,367)	($4,810)	($4,022)	$13,041	($9,932)	($5,586)	$4,212	$3,473	$1,432	$8,741
Total	$47,463	$25,153	($10,571)	($9,622)	($8,202)	($11,261)	$9,312	($13,623)	($8,886)	$21,977	$18,168	$15,464	$75,374