BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Update to Schedule 201 - As-Available Rate.	))))))))))	DOCKET NO. UM 2060 JOINT COMMENTS OF COMMUNITY RENEWABLE ENERGY ASSOCIATION, RENEWABLE ENERGY COALITION, AND NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

INTRODUCTION AND SUMMARY

The Community Renewable Energy Association ("CREA"), the Renewable Energy Coalition, and the Northwest and Intermountain Power Producers Coalition (jointly referred to herein as the "Industry Associations") hereby submit comments to the Public Utility Commission of Oregon ("OPUC" or "Commission") in the above-captioned case.

Instead of approving Portland General Electric Company's ("PGE's") proposal, the Commission should reaffirm existing precedent and require PGE to use well-established market index prices for the Mid-Columbia ("Mid-C") market hub for the as-available (also referred to as "non-firm") rates offered to qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act of 1078 ("PURPA") and state law implementing PURPA. The Industry Associations recommend that the Commission require PGE to calculate as-available/non-firm rates using a quarterly forward market price, as approved repeatedly in Docket No. UM 1561. Alternatively, the Commission should require PGE to calculate as-available/non-firm rates based on a discount to the Intercontinental Exchange's ("ICE's") day-ahead firm Mid-C price, as is currently approved for both PacifiCorp and Idaho Power.

There is no compelling reason for approval of PGE's proposal to use California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM") pricing for the as-available energy pricing offered to QFs. The EIM provides a momentary price for imbalance energy from a limited slice of resources bid into the EIM, whereas the Commission has a long-standing practice of using well-established market index pricing from the region's major market hub, the Mid-C, to calculate as-available avoided cost rates for all three of Oregon's investor-owned utilities, including PGE. In addition, the Commission has already determined that the Mid-C is a reasonable proxy for the markets that PGE buys and sells power to for certain purposes under PURPA. For example, PGE's currently existing Schedule 201 pays QFs based on the Mid-C index when a QF elects a non-fixed price payment, and damages under its standard power purchase agreement are determined by the Mid-C price index. Moreover, the Federal Energy Regulatory Commission ("FERC") has declared that an energy imbalance market does not reflect lawfully set avoided costs for a utility. PGE has not demonstrated that the momentary and unpredictable EIM pricing for imbalance energy is an accurate reflection of PGE's full avoided costs of energy, and PGE itself recently asserted to the Commission that EIM *does not reflect PGE's hourly avoided energy costs*. Therefore, based on the record at this time, the proposed use of EIM imbalance pricing would not constitute a lawful or reasonable implementation of PURPA.

While the issue presented may appear to have isolated importance, the Industry Associations stress that the as-available avoided cost rates could have significant future impact on multiple Commission policies, and allowing use of EIM pricing for this purpose would be a significant change in Commission policy. FERC has proposed a new federal PURPA rule under which states could use as-available pricing in place of long-term fixed pricing for the energy component of rates offered to QFs in long-term contracts. The as-available avoided cost rates could also have a significant impact on Oregon's community solar program and net metering policy, where excess energy could be priced using the as-available avoided costs. In addition, the Commission is planning on its own generic PURPA investigation into avoided cost prices and it should not approve a significant, yet *ad hoc*, change in avoided cost pricing in this proceeding. Because PGE presents no compelling basis to depart from the Commission's existing precedents and existing FERC precedent proscribes use of imbalance markets to set avoided costs, the Commission should not approve PGE's novel proposal.

Finally, the Commission should require PGE to correct confusing language in its Schedule 201 that suggests PGE will not pay off-system QFs the full, long-term avoided costs for energy delivered in excess of nameplate capacity due to whole-megawatt scheduling conventions.

REGULATORY BACKGROUND

The as-available avoided cost rates are one of the three rate options that PURPA and related state law require the utilities to offer to QFs.[1] Under PURPA, must-purchase rules require the following three rate options be offered to QF sales made:

- On an "as-available" basis without a contractual obligation at the utility's "avoided costs calculated at the time of delivery";[2]

[1] *See* 18 CFR § 292.304(d).
[2] *Id.* at § 292.304 (d)(1).

- Pursuance to a legally enforceable obligation with rates based, at the QF's election, on either
  - the "avoided costs calculated at the time of delivery";[3] or
  - the "avoided costs calculated at the time the obligation is incurred."[4]

FERC's commentary in promulgating the rule further explains that the as-available rate is an estimate that does not need be the "actual" avoided costs at the precise moment of delivery, but that the as-available rate may include a limited capacity value. FERC's Order No. 69 provides:

> Paragraph (d)(l) provides that a qualifying facility may provide energy or capacity on an "as available" basis, i.e., without legal obligation. The proposed rule provided that rates for such purchases should be based on "actual" avoided costs. Many comments noted that basing rates for purchases in such cases on the utility's "actual avoided costs" is misleading and could require retroactive ratemaking. In light of these comments, the Commission has revised the rule to provide that the rates for purchases are to be based on the purchasing utility's avoided costs estimated at the time of delivery.[5]

The order further states: "In addition to the avoided costs of energy, these costs must include the prorated share of the aggregate capacity value of such facilities."[6]

The OPUC's administrative rules implementing PURPA require the utilities to offer as-available rates that comply with further requirements. With respect to as-available rate option, the rules provide, in relevant part:

> (3) Rates for purchases — time of calculation: Each qualifying facility has the option to:

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3 *Id.* at § 292.304 (d)(2)(i).
4 *Id.* at § 292.304 (d)(2)(ii); *see also* ORS 758.525(2) (containing rate options in state law).
5 *Small Power Production and Cogeneration Facilities*, Docket No RM79-55, Order No. 69, 45 Fed. Reg. 12,214, 12, 224 (Feb. 14, 1980) (footnote omitted).
6 *Id.* at n.14.

> (a) Provide nonfirm energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases must be based on the purchasing public utility's nonfirm energy avoided cost * * * in effect when the energy is delivered * * * *[7]

The rules define "Nonfirm energy" as "energy to be delivered by a qualifying facility to an electric utility on an 'as available' basis; or energy delivered by a qualifying facility in excess of its firm energy commitment. The rate for non-firm energy may contain an element representing the value of aggregate capacity of nonfirm sources."[8]

The rules further describe the difference in the energy costs for non-firm and firm energy as follows:

> (14) "Energy costs" means:
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> (a) For nonfirm energy, the incremental costs associated with the production or purchase of electric energy by the electric utility, which include the cost of fuel and variable operation and maintenance expenses, or the cost of purchased energy;
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> (b) For firm energy, the combined allocated fixed costs and associated variable costs applicable to a displaced generating unit or to a purchase.[9]

Procedurally, the Commission's rules require quarterly updates to the non-firm avoided costs. The rules state: "Each public utility contracting to purchase nonfirm energy from a qualifying facility under OAR 860-029-0040(3)(a) must file with the Commission each quarter its nonfirm energy avoided cost."[10]

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[7] OAR 860-029-0040(3).
[8] OAR 860-029-0010(21).
[9] OAR 860-029-0010(14).
[10] OAR 860-029-0080(4).

ARGUMENT

1. The Commission Should Require PGE to Follow the Commission's Existing Precedent for Calculation of Non-firm/As-available Avoided Costs

The Commission has longstanding methods approved for calculation of the non-firm avoided costs, but PGE's application fails to even acknowledge, let alone address, these existing methods. Consistent with Order No. 07-360, all three Oregon utilities have consistently used the available market hubs to calculation the as-available avoided costs, including PGE.

PGE has itself previously submitted quarterly rate updates for its own non-firm avoided cost rates based on a forecasted market price in Docket No. UM 1561. As required by the Commission's administrative rules, the as-available/non-firm rate would be available until updated in the next quarter.[11] As PGE has acknowledged in discovery in this proceeding, the rate used in Docket No. UM 1561 was PGE's own internal market price curves as opposed to a publicly available index, but those internal price curves were forecasted Mid-C market prices that remained fixed until the next quarterly update.[12] The use of a quarterly rate is consistent with FERC's guidance in Order No. 69 that the rate need not be a precise momentary avoided cost, but need be merely a reasonable estimate of the avoided costs at the time of delivery of power.[13] The Commission has approved this methodology of calculating PGE's non-firm

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11 *Id.*

12 Attachment A, PGE's Response to CREA's Information Request No. 05(b), stating: PGE based the prices filed under UM 1561 on the most recent forward market curves for the firm Mid-C market during the relevant quarter. The monthly weighed average forward market price was adjusted to account for transmission losses and transmission costs based on BPA Transmission costs. Lastly, the monthly prices were adjusted to obtain a final quarterly weighted average number for the on and off-peak avoided costs.

13 45 Fed. Reg. at 12,224.

avoided costs at least 10 times from 2011 to 2014.[14] Indeed, that is the only method PGE has used for as-available/non-firm avoided costs since issuance of Order No. 07-360.

As PGE notes in its application, the Commission's directive in Order No. 07-360 states a preference for the use of a non-firm index price as the basis for the as-available avoided costs, but in recent years the previously available non-firm index prices for Mid-C have been discontinued. The general distinction between a firm and non-firm index price is that a firm price reflects the prices for power sold with a day-ahead firm commitment whereas a non-firm price is power sold without a firm commitment. The formerly available Dow Jones index provided both a firm and non-firm price on a daily heavy-load and light-load basis for Mid-C, but the Dow Jones index was discontinued in 2013. However, the discontinuance of a non-firm index price has not precluded use of well-established indexes to approximate a non-firm price. In a proceeding in Idaho after discontinuance of the non-firm Dow Jones index, the Idaho Public Utilities Commission ("IPUC") approved a multiparty stipulation that calculated an adjustment to the ICE day-ahead index to approximate a non-firm Mid-C price.[15] The approved approximation of a non-firm rate was 82.4% of the monthly arithmetic average of each day's ICE daily firm Mid-C Peak Avg and Mid-C Off-Peak Avg index prices – a calculation that is easily computed at the end of each month just prior to monthly payments are made to the QF for

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[14] *See Re PGE Quarterly Non-Firm Avoided Cost Rates*, Docket No. UM 1561, Order No. 11-519, Order No. 12-105, Order No. 12-225, Order No. 12-377, Order No. 12-488, Order No. 13-097, Order No. 13-225, Order No. 13-338, Order No. 13-483, Order No. 14-084.

[15] *See Re Tariff Advice No. 13-05 of Idaho Power Company for Authority to Update Schedule 86*, Case No. IPC-E-13-25, Order No. 33053, 2014 Ida. PUC LEXIS 61, *3 (Idaho P.U.C. June 10, 2014).

delivered energy.[16]

Oregon's other two investor-owned utilities still use an adjustment to a firm index price to provide a non-firm/as-available avoided cost price. PacifiCorp uses a blend of multiple hubs (Mid-C, Palo Verde and California-Oregon Border) and implements a discount to the day-ahead market price. PacifiCorp's price schedule provides as follows:

> **Non-Firm Market Index Avoided Cost Prices** Non-Firm Market Index Avoided Cost Prices are available to Qualifying Facilities that do not elect to provide firm power. Qualifying Facilities taking this option will have contracts that do not include minimum delivery requirements, default damages for construction delay or, for under delivery or early termination, or default security for these purposes. Monthly On-Peak / Off-Peak prices paid are *93 percent of a blending of ICE Day Ahead Power Price Report* at market hubs for on-peak and off-peak firm index prices. The monthly blending matrix is available upon request. The NonFirm Market Index Avoided Cost pricing option is available to all Qualifying Facilities. The NonFirm Market Index Avoided Cost Price for Wind Qualifying Facilities will reflect integration costs.[17]

Idaho Power's Oregon rates appear to use a similar discount to the Mid-C day-ahead index prices to that used in Idaho by stating in the rate schedule: "For QFs providing energy on an 'as available' basis, avoided cost rates should be based on day-ahead market index prices for non-firm purchases."[18]

There is no basis in this proceeding to allow PGE to depart from the directive in Order

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16 *Id.*

17 *See* PacifiCorp's Standard Avoided Cost Rate Schedule at 4 (Aug. 24, 2016), available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf.

18 Schedule 85, Cogeneration and Small Power Production Standard Contract Rates, Idaho Power Company, at Sheet 85-12 (Apr. 12, 2016) [hereinafter Idaho Power's Schedule 85], available at https://docs.idahopower.com/pdfs/AboutUs/RatesRegulatory/OregonRates/CogenerationSmallPowerProductionStandardContractRates.pdf .

No. 07-360. The Industry Associations support the use of PGE's previously approved method of filing a quarterly as-available/non-firm avoided cost rate based on estimated non-firm market prices. In particular, the use of forecasted quarterly non-firm rate as previously used by PGE provides the added benefit to the QF and the utility of predictability as to the as-available avoided costs that will be paid. In the alternative, the Industry Associations would not oppose PGE using a reasonably approximated a non-firm index price through use of the available index prices for the market hubs available to them (e.g., Mid-C) similar to PacifiCorp and Idaho Power.

2. PGE Has Not Demonstrated that the Use of Momentary and Unpredictable EIM Pricing Lawfully Estimates PGE's As-Available Avoided Costs

As noted above, FERC's rules require the as-available avoided cost to reflect the utility's avoided costs as calculated at the time of delivery. The only difference between the as-available avoided cost of energy and the long-term, forecasted avoided cost is the time when the calculation is made – the as-available cost is calculated at the time of delivery, whereas the forecasted avoided cost is calculated at the time a QF enters into a contract or other legally enforceable obligation to sell power. Therefore, the rate must reflect a cost of energy sources actually used by the utility, as well as any aggregate capacity value of supply from as-available QFs.

FERC has addressed this very issue and concluded that an imbalance market is not a lawful mechanism to generate the as-available avoided costs of energy for a utility. FERC rejected the Public Utility Commission of Texas's use of an energy imbalance market to set the as-available avoided cost for QFs, explaining: "The problem with the methodology proposed by [Southwestern Public Service Company] and adopted by the Texas Commission is that it is based on the price that a QF would have been paid had it sold its energy directly in the EIS Market, instead of using a methodology of calculating what the costs to the utility would have been for self-supplied, or purchased, energy 'but for' the presence of the QF or QFs in the markets, as required by the Commission's regulations."[19] There is no basis for any different conclusion here.

Notably, PGE's long-term avoided costs use a forecasted day-ahead Mid-C price for the avoided costs during the sufficiency period and the fuel and operating costs of an avoided gas plant during the deficiency period. The EIM prices, in contrast, reflect only an imbalance energy price that a QF would be paid if it somehow sold its energy into the imbalance market. PGE itself has previously confirmed that it does not use the EIM for substantial energy needs. Specifically, in the Commission's resource value of solar docket – where the Commission considered whether to rely on the EIM to generate an hourly price shaping tool – PGE opposed use of the EIM to even generate an hourly price shape for the energy. The Commission's order explains: "PGE does not agree with OSEIA's avoided energy recommendation because: 1) PGE does not use the EIM for large amounts of energy trades. 2) PGE typically uses EIM trades for shorter-term imbalance issues."[20] While the Commission determined to use the EIM to generate an hourly price shape in that case due to a lack of any other apparent method to generate an hourly price shape, the prices themselves were based on wholesale market prices at Mid-C or the fuel and operating costs of a gas plant, just like the traditional avoided costs of energy.[21] In a subsequent compliance filing, PGE reiterated its belief in the limited utility of the EIM by

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[19] *Exelon Wind 1, LLC*, 140 FERC ¶ 61,152, at ¶52 (Aug. 28, 2012); *see also recons. den. Exelon Wind 1*, LLC, 155 FERC ¶ 61,066 (April 21, 2016).

[20] *In re Portland General Electric Company, Resource Value of Solar,* UM 1912, Order No. 19-023 at 8 (Jan. 22, 2019).

[21] *Id.*

asserting: "PGE typically uses EIM for short-term imbalance issues such as 5 and 15- minute markets. This imbalance service ***does not reflect PGE's hourly avoided energy costs***."[22]

PGE should compensate QFs based on avoided cost prices in the Northwest, which is where PGE buys and sells electricity, and using the Mid-C index that the Commission has already determined is appropriate for certain PURPA pricing for PGE. For example, QFs that elect contracts longer than "15 years from the commercial operation date will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15 years after the commercial operation date selected by the Seller and memorialized in the PPA."[23] Similarly, PGE's current power purchase agreement has limited damages provisions, some of which are based at least in part upon the "Lost Energy Value."[24] PGE's Lost Energy Value calculations are extremely complex but are based in part upon "Mid-C Index Price for On-Peak and Off-Peak Hours …"[25]

PGE's approach could produce absurd results. In February 2020, the Mid-C prices spiked, with the average daily price over $90 per MWh and "[s]ome daily prices were well over

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22 Docket No. UM 1912, PGE Compliance, at 2 (March 18, 2019).

23 Schedule 201 Qualifying Facility 10 MW or Less Avoided Cost Power Purchase Information, at Sheet No. 201-5 (May 20, 2020) [hereinafter PGE Schedule 201], Available at: https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/sell-power-to-pge.

24 PGE In-system Variable PPA, § 3.1.10.4 ("Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 7."). https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/sell-power-to-pge

25 *Id.* at § 1.16.

$100 – like the price response during the polar vortex in the late winter of 2014."[26] Under these circumstances PGE could attempt to charge a QF for damages in excess of $100 if the QF failed to deliver power, but would likely pay a QF delivering power far less than that amount, using EIM prices in a market that PGE is not buying power in. Similarly, in these circumstances, the value of the power that the delivering QF is selling to PGE would exceed California based EIM prices; they should be appropriately compensated for the power that they are causing PGE to avoid by being paid at a rate higher than the California based EIM prices.

In sum, given PGE's own assertion that the EIM "*does not reflect PGE's hourly avoided energy costs*," the EIM cannot lawfully serve as the basis for as-available avoided cost of energy for PGE. The Commission should not approve use of EIM pricing because it would be unlawful on the record presented here.

3. The Commission Should Require PGE's Rate Schedule to Clarify PGE Will Pay Off-System QFs the Long-Term Avoided Costs for Excess Energy Resulting from Whole-MW Scheduling

In addition to proposing to use EIM pricing, PGE's proposed Schedule 201 incorrectly applies Commission precedent with respect to its provision addressing PGE's payment to QFs for energy delivered in excess of the QF's nameplate capacity.

PGE's proposed Schedule 201 at Sheet 201-4, provides:

> ~~The~~ Excluding deliveries above the nameplate capacity in any hour, 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

[26] Steve Simmon, Gas Prices Spike in Response to Late Winder Cold Spell and Pipeline Constraints, Northwest Power and Conservation Council, March 22, 2019, available at https://www.nwcouncil.org/news/gas-prices-spike-response-late-winter-cold-spell-and-pipeline-constraints.

> year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard PPA; and (d) Net Output delivered in the Off-Peak Period~~; and (e)~~. The Company will pay the Seller the As-Available Rate for 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.) [27]

This edit proposes to change PGE's current policy that it will pay the QF the fixed Off-Peak Prices when the QF delivers in excess of its nameplate capacity, and instead will now pay the new as-available price for deliveries in excess of nameplate capacity.

The Industry Associations do not object to use of the as-available prices for this purpose because it is consistent with the Commission's order on the subject, but the Industry Associations object to PGE's proposed language that fails to properly clarify the treatment of off-system QFs. Specifically, the Commission's order on this subject provides that "deliveries above the QF's nameplate rating solely for the purpose of accommodating hourly scheduling in whole megawatts by a third party transmission provider do not constitute 'excess energy.'"[28] That policy makes good sense because an off-system QF will often need to schedule a whole MW delivery in excess of nameplate capacity in some hours in order to balance out to a monthly netting of their average net output.[29] For example, Staff in Docket No. UM 1129 used the example of a QF that has a nameplate capacity of 3.5 MW and generates at capacity all hours of the monthly billing period.[30] Such a QF would need to schedule 3 MW half of the hours and 4

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27 (Alterations proposed by PGE in underline and strikethrough).

28 *In re Public Utility Comm'n of Oregon, Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities, Docket No. UM 1129*, Order No. 07-360 at 4 (Aug. 20, 2007).

29 *See* UM 1129 Phase II Staff/2200, Brown/5-8.

30 *See id.* (using this same example).

MW the other half of the hours (ignoring on-peak and off-peak hours for this example) to deliver its entire net output to PGE in the month, and if it does so, the QF should be paid full avoided cost rate for on-peak and off-peak hours for such scheduled and delivered energy. However, PGE's Schedule 201 has incorrectly suggested that PGE will pay the lower off-peak fixed prices for the increment of power in each hour in excess of nameplate capacity. Despite committing in 2007 to correct this issue and implement the tariff properly,[31] PGE has never corrected the issue and now proposes to exacerbate the confusion with its proposed revisions in this case.

Specifically, the new revisions exacerbate the problem by suggesting PGE will "[e]xclude" from payment at the Off-Peak rates in the applicable fixed-price rate table any Of-Peak "deliveries above the nameplate capacity *in any hour*" even if such deliveries are made to accommodate scheduling in whole MW increments.[32] That is unacceptable. PGE's Schedule 201 should unambiguously state that deliveries above the QF's nameplate rating solely for the purpose of accommodating scheduling in whole megawatts by a third-party transmission provider will be paid the applicable On-Peak or Off-Peak rates in applicable fixed price rate tables. PGE itself agreed in a discovery response that such treatment is appropriate under Commission policy,[33] and therefore its Schedule 201 should unambiguously state as such.

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31 *See id.* (discussing PGE's commitment to properly implement this policy).

32 PGE Schedule 201, supra 23, at Sheet 201-4 (emphasis added).

33 Attachment A, PGE's Response to CREA Information Request No. 06(a) states, in relevant part: "PGE agrees that deliveries above the QF's nameplate rating that are solely for the purpose of accommodating hourly scheduling in whole megawatts by a third-party transmission provider should not be included in the amount that is paid either the off-peak rates (PGE's current schedule) or the "as available" rate (PGE's proposed schedule)."

CONCLUSION

For the reasons explained above, the Industry Associations recommend that the Commission require PGE to calculate as-available/non-firm rates using a quarterly forward market price, as approved repeatedly in Docket No. UM 1561. Alternatively, the Commission should require PGE to calculate as-available/non-firm rates based on a discount to the ICE day-ahead firm Mid-C price. Finally, the Commission should require PGE to correct confusing language in its Schedule 201 that suggests PGE will not pay off-system QFs the full, long-term avoided costs for energy delivered in excess of nameplate capacity due to whole-megawatt scheduling conventions.

RESPECTFULLY SUBMITTED this 26th day of May 2020.

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