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June 17, 2013

Via Electronic and U.S. Mail

Public Utility Commission of Oregon
Attn: Filing Center
P.O. Box 2148
Salem, OR 97308-2148
puc.filingcenter@state.or.us

Re: OPUC Docket No. UM 1610

Attention Filing Center:

Enclosed for filing in the above-captioned docket are an original and five copies of *OneEnergy, Inc.'s Post-hearing Brief (Phase I).*

An extra copy of this letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann
Ken Kaufmann
Attorney for OneEnergy, Inc.

cc: UM 1610 Service List

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1610

In the Matter of **PUBLIC UTILITY COMMISSION OF OREGON,** **Investigation Into Qualifying Facility Contracting and Pricing.**	**ONEENERGY, INC.'S POST-HEARING BRIEF (Phase I)**

Pursuant to ALJ post-hearing order issued May 30, 2013, OneEnergy, Inc.[1] hereby submits this post-hearing brief on the issues in Phase I of this docket.

I. INTRODUCTION

The Commission convened this investigation to address seven separate dockets concerning Oregon's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[2] ALJ Ruling, Docket No. UM 1610, at p. 2 (December 21, 2012). These dockets implicate broad policy issues that together will chart the future of PURPA in Oregon for the next decade. Portland General Electric ("PGE") and Idaho Power Company assert that the current PURPA framework adopted by the Commission in Docket No. UM 1129 incorrectly implements PURPA and threatens significant harm to utility customers. However the recent history of development of qualifying facilities ("QFs") in Oregon does not support these assertions. The end of the Business Energy Tax Credit, coupled with a severe correction of natural gas market prices starting in 2009, have reduced the development of new small QFs in Oregon to a trickle. Utilities increasingly rely upon natural gas-fired generation to meet load, increasing customers' exposure to gas price volatility, future carbon emissions-related costs, and reliability risks due to a regional shortage of firm gas supply capacity during peak demand periods. The utilities'

[1] OneEnergy Inc. is a Washington corporation headquartered in Seattle with an office in Portland, that develops renewable energy projects and plans to develop solar photovoltaic projects under 5 MW in Oregon.

[2] Pub. L. No. 95-617, 92 Stat. 3117 (codified in scattered sections of 15, 16, and 30 U.S.C.).

proposed changes would exacerbate these risks. Rather than implementing foundational changes to the UM 1129 framework, what is needed now is improved implementation of the existing framework and incremental changes necessary to facilitate development of community-scale renewable generation without increasing customer rates. OneEnergy's positions on UM 1610 issues, in the order established by the Commission, are provided in Section III, below.

II. APPLICABLE LAW

A. PURPA

PURPA is one of five pieces of major legislation comprising the National Energy Act—which Congress enacted in 1978 in response to the Arab oil embargo of 1973. Two of PURPA's purposes are: (1) to reduce demand on fossil fuels; and (2) to overcome traditional reluctance of utilities to buy power from, and sell power to, non-utility generators.[3]

In October 2010, the Federal Energy Regulatory Commission ("FERC") published a decision that changed our collective understanding of PURPA.[4] The FERC FiT Order held for the first time that, where a state requires utilities to acquire resources from generators with certain characteristics (e.g. a renewable portfolio standard), the state can authorize an avoided cost based only on generators that meet the state's procurement requirements (e.g. renewables).[5] The FERC FiT Order led to the Commission's current efforts to implement a renewable avoided cost rate.[6]

B. Oregon law

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[3] *See FERC v. Mississippi*, 456 U.S. 742, 750 (1982).

[4] *California Public Utilities Commission*, 133 FERC ¶ 61,059 (2010) ("FERC FiT Order").

[5] Previously, FERC held that avoided cost must be the lowest cost alternative available from any source. *So. Cal. Edison*. 70 FERC ¶ 61,215 (1995) ("*SoCal Edison*"), *order on recon.*, 71 FERC ¶ 61,269 (1995). FERC's holding became known as the "all-source rule" because it requires utilities to consider all available sources when determining avoided cost.

[6] Order No. 11-505 at 5.

Oregon's statutes implementing PURPA are codified at ORS 758.505 to ORS 758.555. ORS 758.515(2) provides that "[i]t is the goal of Oregon to:"

> (a) Promote the development of a diverse array of permanently sustainable energy resources using the public and private sectors to the highest degree possible; and
>
> (b) Insure that rates for purchases by an electric utility from, and rates for sales to, a qualifying facility shall over the term of the contract be just and reasonable to the electric consumers of the electric utility, the qualifying facility and in the public interest.

In 2005, the Commission undertook a comprehensive investigation of its rules and policies implementing PURPA, in Docket No. UM 1129. The orders from that investigation, including Order No. 05-584, Order No. 06-538, and Order No. 07-360, established the current framework for QF contracting with investor owned utilities in Oregon.

In 2007, Oregon enacted Senate Bill 838, which established a renewable portfolio standard ("RPS") requiring large utilities to provide 25 percent of their retail electric sales from new renewable energy sources by 2025. ORS 469A.052 (2011). SB 838 also contains a goal that small-scale renewable energy projects with a generating capacity of 20 megawatts or less comprise at least eight percent of Oregon's retail electrical supply by 2025. It directs all executive agencies of the state to establish policies and procedures promoting the eight percent goal. ORS 469A.210 (2011).

In 2011, the Commission adopted a policy framework for a renewable-based avoided cost price option based on FERC's FiT Order, and directed PacifiCorp and PGE to file applications with supporting testimony setting forth proposed rates and tariffs for a renewable avoided cost available only to those QFs whose output counted towards compliance with the RPS in SB 838. Order No. 11-505. The utilities complied with this request. However, the renewable avoided cost is unimplemented and is pending the outcome of the Commission's investigation in this docket.

C. Applicable Legal Standard

PURPA avoided cost rates must be just and reasonable and shall not discriminate against QFs. 18 C.F.R. § 292.304(a)(1); ORS 758.515(2)(b). Existing approved Commission tariffs are *prima facie* just and reasonable. *State v. Southern Pacific Co*., 23 Or 424, 433, 31 P. 960, 962 (1893). Neither the Commission nor an Oregon court have decided which party bears the burden of proof in the context of changing avoided cost rates pursuant to PURPA. Under the Federal Power Act, Section 205 (16 U.S.C. § 824d (2012)), the party seeking to change the *status quo* has the burden to demonstrate that its proposed change is just and reasonable, and not unduly discriminatory or preferential. *Idaho Power Co.*, 137 FERC ¶ 61,235, P 21 (2011). At least one state has embraced this approach when investigating state regulated PURPA avoided cost rates.[7] However if this investigation is a ratemaking subject to ORS 757.210, then the utility bears the burden of showing that a rate proposed to be established, increased, or changed is fair, just and reasonable based on the record from the hearing. *Id*. To reach a determination on whether proposed rates are just and reasonable**,** the Commission looks at the record as a whole and makes a determination based on the preponderance of the evidence.[8]

D. "Full Avoided Cost" Under PURPA

With exceptions not relevant to this docket, PURPA requires that utilities purchase QF

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[7] *See Petition of Inquiry into the Rates Paid by Houston Lighting & Power Co. to Qualifying Facilities for the Purchase of Non-firm Energy,* Texas PUC Docket No. 5994, 12 Texas P.U.C. Bulletin 795, 28-31, 1986 Tex. PUC LEXIS 48, (1986) ("Section 40 of the Act clearly places the burden of proof on a utility in a rate proceeding. However, this proceeding is not a rate proceeding within the definition of rate as used by the Act * * * In this case the "rates" are those being paid by the utility to its vendor. * * * Should [the utility] solely be assigned the burden of proof and fail to meet it, the issues would still be un-resolved. As a practical matter, a dispute would still exist, absent a stipulation, * * * therefore some party must be allocated a burden of proof. Consequently, the ALJ is of the opinion that each party seeking specific relief must carry a burden as regards that relief.").

[8] *In the Matter of PGE Co. 2012 Annual Power Cost Update Tariff (Schedule 125),* OPUC Docket No. UE 228, Order No. 11-432, 3 (2011).

net output at the utility's full avoided cost.[9] Within this constraint, PURPA delegates to state public utility commissions (PUCs) wide latitude in setting avoided cost rates for investor owned utilities.[10] Setting purchase rates above or below avoided cost violates PURPA.[11] PUCs necessarily can and must make approximations in the interest of administrative efficiency.[12] Approximations to avoided cost that provide certainty with respect to the QF developer's return on investment are consistent with PURPA if the overestimations and underestimations of avoided cost balance out.[13]

The governing definition of "avoided cost" appears in 18 C.F.R. § 101(a)(6):

> *Avoided costs* means 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.

FERC Order No. 69 explains that "avoided cost" includes "both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities." *Id*. at 12,216. As used in the definition, "incremental" refers to the principle of economic dispatch, wherein the "utility can avoid operating its highest-cost units." *Id*. The utility's average system costs are not the same as incremental costs. *Id*. Avoided cost of

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[9] *Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 417 (1983) (upholding FERC's rule in 18 C.F.R. § 292.304(b)(2) that utilities purchase QF net output at the utilities' *full* avoided cost); *see also Indep. Energy Producers Ass'n v. California Pub. Utils. Comm'n*, 36 F.3d 848, 851 (9th Cir. 1994) ("[FERC rules] require that utilities purchase electric energy from and sell electric energy to QFs at the Utility's full "avoided cost" rate. 18 C.F.R. § 292.304(d).").

[10] *Indep. Energy Producers Ass'n*, 36 F.3d at 856 (quoting *Administrative Determination of Full Avoided Costs Sales of Power to Qualifying Facilities, and Interconnection Facilities*, IV Federal Energy Reg. Comm'n Rep. (CCH) Par. 32,457, at 32,173 (Mar. 16, 1988)).

[11] *Connecticut Light & Power Co.*, 70 FERC ¶ 61,012, 61,029-030 (1995).

[12] 18 C.F.R. § 292.304(b)(5) (2012) ("In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract…, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.").

[13] *See* FERC Statutes and Regulations, Regulations Preambles 1977-1981, P30,128, at p. 30,881. 45 Fed. Reg. 12,214 (Feb. 25, 1980) ("FERC Order No. 69") ("The Commission does not believe that the reference in the statute to the incremental cost of alternative energy was intended to require a minute-by-minute evaluation of costs which would be checked against rates established in long term contracts between qualifying facilities and electric utilities. Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these latter arguments, and believes that, in the long run, "overestimations" and "underestimations" of avoided costs will balance out.").

new capacity should be included when a QF allows a utility to avoid the addition of new capacity. *Id*. Avoided cost includes the cost of generation *and transmission* that the utility would have incurred under its "optimal capacity expansion plan" but for the addition of a qualifying facility. *Id*. "An optimal capacity expansion plan [avoided by the addition of QFs] is the schedule for the addition of new generating *and transmission facilities* which, based on an examination of capital, fuel, operating and maintenance costs, will meet a utility's projected load requirements at the lowest total cost." *Id*. at n.6 (emphasis added).

III. SUMMARY OF POSITIONS

1. <u>Avoided Cost Price Calculation</u>

1.A.i. Should the Commission retain the current method based on the cost of the next avoidable resource identified in the company's current IRP, allow an "IRP" method-based on computerized grid modeling, or allow some other method?

The current framework adopted in UM 1129 should be retained because the record does not demonstrate foundational changes are warranted. *See* Issue 5.A, *infra*. Resolution of the implementation issues below, however, will improve the current system without the large risk associated with changes in the base methodology.

<u>Reaffirm that Current Methodology Requires Full Avoided Cost</u>.[14] Although costs of CCCTs have evolved since UM 1129, avoided cost methodologies have not kept up. Utilities argue that higher rates for QFs result in higher rates for retail customers. However, if resource decisions are made based on underestimates of the true cost of utility self-built resources, customers suffer. In several respects, current methodologies either omit major CCCT expenses or make stakeholder vetting of cost inputs impossible. These costs include firm gas transportation, transmission capacity, water rights, taxes, and operating efficiency (due to elevation and wet/dry

[14] PURPA's mandate that QF avoided cost rates equal the utility's full avoided cost is discussed on pages 5-6, *supra*.

cooling). When these costs are properly accounted the Commission may find that the full cost of the utilities' resource additions *exceeds* the cost of QF alternatives.

Properly account for cost of firm CCCT fuel supply. Commission guidance is needed to reaffirm that the cost to procure firm fuel capacity rights on gas pipelines is part of the full avoided cost of the proxy CCCT.[15] The record shows substantial gas firming costs for CCCTs. But these costs are not included in avoided cost rates. Under PURPA, these costs must be included in avoided cost rates because they are direct costs of building and operating a CCCT.[16] The Commission recently recognized the importance of gas supply in Order No. 12-398 by requiring RFP participants to demonstrate access to adequate gas. *In the Matter of Portland General Electric Co. Request for Proposals for Capacity and Baseload Resources*, OPUC Docket No. UM 1535, Order No. 12-398, 2 (2012) (requiring bidders in an RFP for flexible capacity product to provide one of three specified solutions to ensure reliable gas service). Avoided cost rates must recognize that the addition of a CCCT to the gas transportation system requires costly laterals and local upgrades to insure the needed firm gas. Fixed price demand charges arise from long-term contracts wherein the pipeline company builds out its system and commits to providing firm gas transport capacity to the CCCT. OneEnergy/200, Eddie/12. The record demonstrates that these charges are significant. The fixed price demand charges for incremental firm service to PacifiCorp's recent Lake Side 2 CCCT totals [**BEGIN**

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[15] Staff, ODOE, CREA, and RNP concur that gas firming costs should be included in avoided cost rates. Staff/200, Bless/5-6; ODOE/100, Carver/8; CREA Memorandum at 11; RNP Memorandum at 2-3 (if capacity adjustment is made).

[16] *See, e.g., Investigation into CL&P and UI Third Annual Filing of the Status of Cogeneration and Small Power Production Projects,* Conn. Dept. of Pub. Util. Control Docket No. 88-04-02, 99 P.U.R.4th 61, 1988 Conn. PUC LEXIS 133, *4 (1988) ("The fuel costs for the combined cycle proxy unit in this analysis are the product of three components: the forecasted price of the fuel supply, the average annual heat rate, and the estimated energy production per year. The fuel supply for the combined cycle is *firm* natural gas at a proxy cost equal to DRI's forecasted price for #6, 1.0 percent sulfur oil.") (emphasis added).

CONFIDENTIAL][redacted]**END CONFIDENTIAL**] per month, or [**BEGIN CONFIDENTIAL]**[redacted][**END CONFIDENTIAL**] annually, for 30 years. OneEnergy/200, Eddie/12. According to public records, the annual cost to PGE for the lateral to provide firm gas transportation to its Carty CCCT will be $10,880,000, $10,516,000, and $10,105,000 in the first three years of a 30-year contract. *Id*. PGE alone of the three utilities accounts for any gas firming costs in its avoided cost rates.[17] PacifiCorp's and Idaho Power's avoided cost rates do not include fixed price demand charges for gas transportation.[18]

Although PGE does include fixed price demand charges for gas transportation, it appears to use its system-average price. OneEnergy/100, Eddie/28, lines/3-12. This is contrary to PURPA, which requires the use of incremental, not average, avoided costs. FERC Order No. 69, 45 Fed. Reg. at 12,216 ("The utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs."). The omissions of gas transportation charges discussed above show significant differences between avoided cost rates and actual costs to construct and operate CCCTs. As discussed below, the unaccounted for costs are expected to grow.

The utilities fail to account for significant pipeline trunk upgrades anticipated by Bonneville Power Administration and Northwest Gas Association. OneEnergy/100, Eddie/23-25[19]; OneEnergy/200, Eddie/10-15. Each of the utilities acknowledges future pipeline constraints

[17] OneEnergy/204, Eddie/2-4 (table showing which categories of gas transportation costs PGE includes in its avoided cost rates).

[18] OneEnergy/205, Eddie/4-5 (table showing which categories of gas transportation costs PacifiCorp includes in its avoided cost rates); OneEnergy/203, Eddie/4-5 (table showing which categories of gas transportation costs Idaho Power includes in its avoided cost rates).

[19] The needed trunk upgrades may be similar in scale to the $3,712,000,000 Ruby Pipeline expansion discussed in OneEnergy/100, Eddie/24.

to some degree.[20] Yet, none of the utilities have studied the potential cost of trunk upgrades. OneEnergy/200, Eddie/11. In response to a data request from OneEnergy, PGE asserted that GTN's website shows available pipeline capacity. OneEnergy/204, Eddie/1. However, PGE has not provided evidence to demonstrate that long-term firm transportation capacity will be available in sufficient volume to fuel future CCCTs.

In sum, determining the full avoided cost rate requires accounting for firm gas supply to the proxy CCCT. With the exception of PGE, current avoided cost methodologies do not include *any* adjustment for fixed price demand charges. Full avoided cost, consistent with PURPA, would include direct costs and fixed price demand charges of providing firm fuel to the next avoidable CCCT proxy, including costs of any necessary gas storage, lateral, and upgrades to local and trunk pipelines. OneEnergy asks the Commission to confirm that the utilities must include these costs in the CCCT proxy.

Reaffirm that Full Avoided Cost includes state and local taxes. OneEnergy asks that the Commission reaffirm that state and local taxes are a component of the full avoided cost of the CCCT proxy. See Issue 2.A, *infra*.

Specify location of Proxy CCCT. In Docket No. UM 1129, the proxy resource used by the utilities to calculate avoided cost had a presumed location. The location of the CCCT proxy is necessary so the utility can follow guidelines 13 and 14 for negotiating non-standard power purchase agreements, which were adopted by the Commission in Order No. 07-360:

> 13. The utility should adjust avoided cost rates for QF line losses *relative to the utility proxy plant based on a proximity-based approach*.

[20] Idaho Power assumes pipelines costs for additional CCCT units will "approximately double". OneEnergy/200, Eddie/11, lines/3-5. PacifiCorp has acknowledged that new natural gas plants may require construction of additional pipeline capacity at additional cost. OneEnergy/100, Eddie/24, lines/7-8. In 2011, PGE stated that it had no more gas storage available for purposes of its RFP. OneEnergy/100, Eddie/24, lines/5-6.

> 14. The utility should evaluate whether there are potential savings due to transmission and distribution system upgrades that can be avoided or deferred *as a result of the QF's location relative to the utility proxy* plant and adjust avoided cost rates accordingly.

Order No. 07-360, Appendix A (Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs 10 MW or Larger) (emphasis added). However, PacifiCorp assumes that its proxy plant will always reside at an "optimum" location relative to load. PacifiCorp's Prehearing Memorandum at 3, 10. But PacifiCorp's assumption, if correct, would render meaningless guidelines 13 and 14, because a QF will never have location related savings compared to an optimally located proxy plant. OneEnergy could find no basis in Commission rules or orders for PacifiCorp's assumption. Specifying location is necessary for determining other aspects of avoided cost, including: applicable state taxes, altitude impacts on efficiency, cost of firm gas supply, incremental transmission upgrade costs, and regional construction costs. Specifying the location of a proxy is particularly important with regard to PacifiCorp and Idaho Power, whose systems span multiple states. OneEnergy asks the Commission to reaffirm that utilities must specify the location of the CCCT proxy so that all elements of avoided cost can be ascertained.

Negotiated Rates. PacifiCorp's proposal to use its own proprietary models and its "PDDRR" methodology for QFs over 3 MW should be rejected because it is unsupported by substantial evidence in the record. "Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling… It is not theory but the impact of the rate order which counts."[21] PacifiCorp has provided no evidence of what avoided cost rates will result if the Commission grants its request. It is impossible to know from the record whether PDDRR derived rates are higher or lower than the Oregon methodology, how they differ by

[21] *Fed. Power Comm'n. v. Hope Natural Gas Co.,* 320 U.S. 591, 602 (1943) (J. Douglas) (internal citations omitted).

resource, and how they differ over time. A request to change a rate, without evidence demonstrating what the resulting rate will be, is not just and reasonable.[22]

Idaho Power's proposal to use its "incremental IRP methodology" based upon its AURORA model for Non-Standard agreements also lacks sufficient evidence that it is just and reasonable. The Commission previously found that Idaho Power's AURORA model failed to accurately forecast gas prices under normalized hydro-year conditions. Order No. 05-871, p. 8. The Commission ordered: "[i]f the company chooses to again rely on the AURORA model in a future rate case, we direct the company to hold workshops to allow intervenors and Staff to examine the model more thoroughly." *Id.* Idaho Power did not hold a workshop to answer questions about its AURORA model—nor did Staff itself investigate the methodology.[23] Although Idaho Power gave some predictions about the resulting rates, the data are insufficient to show that the resulting prices over the expected range of sizes and types of QF applicants are just and reasonable.

1.A.ii. Should the methodology be the same for all three electric utilities?

QFs delivering to PacifiCorp in southern Oregon should receive California-Oregon Border ("COB") forward prices during the sufficiency period. Price differences in trading hubs exist because of transmission constraints. ODOE/400, Carver/8. OneEnergy agrees with ODOE that Mid-Columbia ("Mid-C") should be used unless a QF is delivering to PacifiCorp "south of either the Alvey transmission substation near Eugene or the Grizzly substation near Redmond

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[22] *See In the Matter of Idaho Power Co. Application for general rate increase*, OPUC Docket No. UE 167, Order No. 05-871, 12 n.9, 243 P.U.R. 4th 185 (2005) ("At oral argument, the company was asked about the impact this rate design may have on different groups of residential customers. The company had no response or supporting data. *Without more evidence in the record regarding the impact of higher summer rates on Oregon customers, we conclude that the proposed block rate design is not just and reasonable and should not be approved*.") (emphasis added).

[23] Staff/100, Bless/9, lines/5-12. (recommending that Oregon retain the standard methodology because the changes proposed by the utilities would increase opacity and complexity without necessarily providing more accurate results).

receive prices based on the COB hub price." ODOE/400, Carver/9. In 2012, On-Peak prices at Mid-C averaged $4.25/MWh less than On-Peak prices at COB. OneEnergy/200, Eddie/6-7. The evidence in the record demonstrates that the COB index more closely approximates PacifiCorp's avoided cost in its southern Oregon territory and may be implemented with inconsequential administrative burden.

1.B. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?

OneEnergy proposes allowing QFs to elect tilted rates, meaning rates escalating 2% annually over the term of the PPA.[24] Tilted rates (or levelized rates) make QF projects more financeable while maintaining a price-signal for the utility's sufficiency period. The Commission's stated purpose of the sufficiency period is to make avoided cost rates reflect actual capacity avoided by the utility. Order No. 05-584 at 27. Tilted rates would not upset that purpose because they inversely correlate to the number of years of sufficiency in a PPA: the higher the number of sufficiency years, the lower the rates. OneEnergy/200, Eddie/20-21. Tilted rates, however, would dull the crippling effect sufficiency periods have on QFs' ability to obtain construction financing. OneEnergy/200, Eddie/19. A critical metric for such financing is minimum debt service coverage ratio. OneEnergy/200, Eddie/19; *see* ODOE/200, Elliott/5 (loan qualification depends on PPA prices). Minimum debt service coverage ratio means the lowest ratio of net revenue to debt service during all re-payment periods of a loan's term. OneEnergy/200, Eddie/19. For example, OneEnergy understands that ODOE is prohibited from granting loans to a project with a minimum debt service coverage ratio of less than 1.25. OneEnergy/200, Eddie/19.

[24] In UM 1610, the parties have used "levelized rates" to refer to equal rates for each year of a contract and "partially levelized rates" to refer to rates that escalate at a constant rate each year, although that term was used differently in past Commission proceedings. OneEnergy adopts the term "tilted rates", to mean rates that escalate at a constant rate each year. A "2% tilted rate" means rates that escalate 2% per year.

Disproportionately low revenue in early years restricts the financing potential of a project. OneEnergy/200, Eddie/19. Since Order No. 05-584, a pattern of long sufficiency periods in published avoided cost rates has become a significant obstacle to project financing. PacifiCorp and PGE have maintained average sufficiency periods of close to three years, and never less than one year, in their published rates. OneEnergy/212-13. Annual updates to avoided costs, as proposed by the utilities, will exacerbate the effect of the sufficiency period by increasing the average duration of the sufficiency period.

The opponents of tilted rates and levelization raise three main objections. First, they argue that levelized rates are inconsistent with FERC's implementation of PURPA. PGE's Prehearing Memorandum at 4; Staff Prehearing Memorandum at 5. This claim is demonstrably false. FERC expressly endorsed levelized rates for the purpose of matching payments to debt service obligations.[25]

Second, opponents argue that the Commission previously decided against levelized rates in Order No. 05-584. Staff Prehearing Memorandum at 5 (citing Staff/100, Bless/12 ("The Commission considered proposals for levelized prices in Docket No. UM 1129 and decided against them."). This argument misreads the order. The Commission expressly did not address levelized rates in Docket No. UM 1129. Order No. 05-584, at 28 n.46 ("[W]e need not address the issue of levelization in this Order"). Even if the Commission had decided against

[25] FERC explained that levelization of QF rates is a permissible means of aligning payments with QF debt service obligations:

> *[A] level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility.* So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or non-regulated electric utility from approving such an arrangement.

American REF-FUEL Company of Lehigh Valley, 47 FERC ¶ 61,208, 61,718 (1989) (quoting FERC Statutes and Regulations, Regulations Preambles 1977-1981, P30,128, at p. 30,881. 45 Fed. Reg. 12,224 (Feb. 25, 1980)) (emphasis added in *American REF-FUEL*).

levelization, the persistently long sufficiency periods since Order No. 05-584 are grounds for revisiting levelization.

Third, opponents argue that levelized rates would place too much risk on the utilities. However, opponents have not adequately demonstrated risk, and the small risk that is apparent can be mitigated. Compared to fully levelized rates, tilted rates have significantly less "overpayment" in early contract years. Regarding risk mitigation, PacifiCorp requests that, if levelization is allowed, security requirements be imposed. PacifiCorp's Pre-Hearing Brief at 4. OneEnergy supports a creditworthiness requirement for QFs seeking tilted rates. OneEnergy/200, Eddie/23-24; OneEnergy/100, Eddie/39-40. Tilted rates are typical for renewable contracts. [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]. Denying tilted rates to similarly situated QFs would be discriminatory against QFs. ORS 758.525(4). Levelized rates have been approved for QFs in several other states, including Idaho, Utah, Vermont, South Dakota, and Georgia.[26]

[26] Idaho: *In The Matter of the Petition Filed by Idaho Power Company for Approval of Modifications to the Security Provisions Required to be Included in Power Purchase Agreements between Electric Utilities ... and PURPA Qualifying Facilities (QFS)*, Idaho PUC Case Nos. IPC-O3-16, AVU-O3-9, PAC-O3-13, Order No. 29587 (2004) (modifying rules for levelized contracts). Utah: *Update of Electric Service Schedule No. 37 Rates for Power Purchases from Qualifying Facilities*, Utah PSC Docket No. 11-035-T06, 2011 Utah PUC LEXIS 396, *8 (Dec. 14, 2011) (updating 20-year levelized price) Vermont: "A qualifying facility which is eligible for firm rates may elect non-levelized rates or, with the permission of the Board, fully levelized rates, or a levelized capacity component and non-levelized energy components." 30-000-015 Vt. Code R. § 4.104(E)(5) (2013). South Dakota: The South Dakota Public Service Commission recently ordered Northwestern Energy to enter into a 20-year PPA with a 19.5-MW wind QF at levelized avoided cost rates "because they will produce a stable price that will better enable [the QF] to finance the Project" *In the Matter of the Complaint by Oak Tree Energy LLC against Northwestern Energy for Refusing to Enter into a Purchase Power Agreement*, S.D. PSC Docket No. EL11-006, 2013 S.D. PUC LEXIS 84 (May 17, 2013). The order did not discuss or directly impose performance security on the QF. Georgia: Levelized rates are available for solar QFs of 1 MW or less. Collateral is required only for QFs over 100 kW. QFs have an option to elect escalated rates and post not security. *In Re: Georgia Power Co.'s Advanced Solar Initiative*, Ga. PUC Docket No. 36325, 2012 Ga. PUC LEXIS 165 (Nov. 20, 2012).

Tilted rates would help Oregon achieve its 8% community renewable energy goal and policy to enable QF development. ORS 469A.210[27]; ORS 758.515(3). Low prices in one or more early years of a power purchase agreement sharply reduces the debt service coverage ratio—and hence the amount a developer may borrow to finance a project. OneEnergy/200, Eddie/19, lines 5-17. Tilted rates will make small QF projects more financeable by increasing project revenue during the sufficiency period. OneEnergy/200, Eddie/19, lines 5-17. Tilted rates do not increase the net present value of a contract and do not put ratepayers at risk if they are adequately securitized. OneEnergy/100, Eddie/39-40; OneEnergy/200, Eddie/19-21. OneEnergy proposes that creditworthy QFs have the option to receive 2% tilted (escalating) payments, with a net present value equal to the present value of the published rates over the same term.

2. __Renewable Avoided Cost Price Calculation__

2.A. Should there be different avoided cost prices for different generation sources?

The renewable avoided cost should not be decremented for integration during the sufficiency period. The Commission already determined, in Order No. 11-505, that QFs should be paid the market price during the sufficiency period.[28]

Commission guidance is needed to remind the utilities that "full avoided cost" must account for *all* costs the utility avoids by purchasing QF output instead of building the avoided renewable resource. This includes expected lost generation due to Balancing Authority curtailments of the renewable resource; expected lost generation due to degradation in performance of the renewable resource over its lifetime; and state and local taxes paid by the renewable resource over its lifetime. OneEnergy/200, Eddie/9-10.

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[27] The 8% goal is discussed on page 3, *supra*. Under the assumptions made in OneEnergy's analysis, Oregon as a whole currently gets about 3.5% of its energy from projects under 20 MW. OneEnergy/100, Eddie/17-18.

[28] *Investigation into Resource Sufficiency Pursuant to Order No. 06-538*, OPUC Docket No. 1396, Order No. 11-505, 9 (2011).

<u>PacifiCorp's Wyoming wind generation bubble transmission costs</u>. PacifiCorp's renewable avoided cost, filed February 13, 2012 in its Docket No. UM 1396 compliance filing, incorrectly excluded the incremental transmission cost to move output from its renewable resource to load. OneEnergy/200, Eddie/7-9. The wind project that PacifiCorp uses as its renewable proxy has incremental transmission costs due to its location in a "wind-generation only bubble." PacifiCorp 2011 IRP, Vol. 1 pp. 128-130 (OneEnergy/202). According to the IRP, those transmission costs "could have been added directly to the wind capital costs." *Id*. However, PacifiCorp did not factor those incremental transmission costs into its proposed renewable avoided cost rates. OneEnergy/200, Eddie/8, lines 2-16; the only transmission costs included in the PacifiCorp wind proxy avoided cost are the "the costs necessary to connect a project to a nearby transmission line or substation." OneEnergy/405. Unless the cost of transmission upgrades needed to export energy out of the Wyoming wind bubble is included, the resultant rates will not be "full avoided cost" as required under PURPA.

At the hearing PacifiCorp elaborated on which transmission costs are included in the Renewable Avoided Cost:

> PacifiCorp did identify that the proxy resources in its integrated resource plan include transmission costs, the cost to interconnect and the costs of system upgrades that are directly attributed to the project.
>
> There are other system upgrades that must be made across PacifiCorp's system. In the case of the 2011 IRP, the Company identified system upgrades that would be required for a large block of resources if a large block of resources were added in the Wyoming transmission area.
>
> Those upgrades are across the—*they are general in nature*. They are at multiple points across the system and would perhaps be necessary with or without the resources at some point in time. The point is, they provide a system benefit. They are not directly attributable to a particular project.

May 23, 2013, Cross Examination Hearing UM 1610, p. 28 (Dickman)(emphasis added). Mr. Dickman's statement that the transmission upgrades are "general in nature", is correct, if he is referring to PacifiCorp's IRP methodology. In the IRP, PacifiCorp segregated incremental transmission costs from the other capital costs of its wind resources. OneEnergy/200, Eddie/8. In the case of the Wyoming wind generation bubble, PacifiCorp calculated that development of 1,500 MW of Wyoming wind would require transmission upgrades at an average cost of $71/kW ($106,500,000.00). This cost is "general in nature" in the sense that it applies undivided to the entire 1,500 MW wind resource.

"General in nature" has a different definition when determining whether the Wyoming wind generation bubble transmission costs should be assigned to a project under PURPA. One cannot shift the allocation of incremental transmission costs from the utility to the QF merely by combining the costs of multiple planned wind projects into a single upgrade. And yet that is what PacifiCorp has done, according to its 2011 IRP:

> Incremental transmission costs also could have been added directly to the wind capital costs. However, assigning a cost to a wind generation bubble avoids the need to individually adjust costs for many wind resources.

PacifiCorp 2011 IRP Vol. 1, p. 128, n.40 (OneEnergy/202). Even the name "Wyoming *wind-generation only* bubble" PacifiCorp uses in the 2011 IRP strongly implies that the transmission to be constructed is for the benefit of moving wind generation out of the bubble. The Commission should order PacifiCorp to assign a portion of the $106,500,000 transmission upgrade costs associated with development of 1,500 MW of Wyoming wind to its wind proxy resource and to include those costs in the renewable avoided cost. [29] Correct assignment of

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[29] PacifiCorp apparently agrees with this principle when determining who should pay for incremental transmission costs associated with load pockets (but not wind-generation only load bubbles). In its Prehearing Memorandum, pp. 9-10, PacifiCorp explains:

> Under PURPA and the Commission's rules implementing PURPA, customer indifference is ensured by relying on a "but-for" causation principle when determining the avoided cost rate and accompanying charges, such as interconnection costs. This requires that costs that would not otherwise be incurred but for the purchase of the QF's energy and capacity must be recovered from the QF.

incremental transmission costs has ramifications beyond the renewable avoided cost—excluding incremental transmission costs in the cost of Wyoming wind projects can change the company's selection of its next preferred resource, and cause regulators to underestimate the cost of such resources.

Treatment of State and Local taxes paid by the renewable proxy. PacifiCorp's renewable avoided cost also incorrectly accounts for state taxes. Wyoming taxes include a 5% state sales tax and a $1/MWh excise tax which apply to wind generation facilities constructed after 2012. At the hearing, PacifiCorp's witness could not explain why PacifiCorp did not include those costs in the renewable avoided cost. May 23, 2013, Cross-Examination Hearing Transcript, pp. 50-53. Clarification that state and local taxes are part of the full avoided cost will facilitate implementation of the renewable avoided cost.

2.B. How should environmental attributes be defined in PURPA transactions?

"Green Tags", as defined in the standard renewable avoided cost power purchase agreement, should not include (1) 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, and (2) any other environmental attributes that are not required in order to provide the purchasing utility with a renewable energy certificate for "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, ORS 469A.010 *et seq.*, in effect at the time of execution of the PPA. OneEnergy/200, Eddie/7, lines/4-15.

3. Schedule for Avoided Cost Price Updates

3.A. Should the Commission revise the current schedule of updates at least every two years and within 30 days of each IRP acknowledgment?

Annual ministerial updates at the same time each year would result in more accurate avoided costs than the current, two-year update frequency. "Ministerial updates" are those updates that can be accomplished transparently without the exercise of independent judgment. OneEnergy/200, Eddie/5.[30] Ministerial updates include updates to gas price and electricity price forecasts, and changes to the Production Tax Credit (which translate dollar-for-dollar to changes in the renewable avoided cost). Changes to the sufficiency period, which depend on subjective estimates of load growth and contracted resources, are not ministerial and should not be part of the annual update.

3.C. Should the Commission specify what factors can be updated in mid-cycle?

See Issue 3(A), above.

3.D. To what extent (if any) can data from IRPs in late stages of review and whose acknowledgement is pending be factored into the calculation of avoided cost prices?

Utilities should not be permitted to make non-ministerial updates to avoided costs without notice and opportunity for examination of the proposed changes by interested parties. All avoided cost data submitted to the Commission is subject to review by the Commission and the utilities have the burden of justifying such data. 18 C.F.R. § 292.302(e). Use of data from unexamined reports does not satisfy PURPA.

3.E. Are there circumstances under which the Renewable Portfolio Implementation Plan should be used in lieu of the acknowledged IRP for purposes of determining renewable resource sufficiency?

[30] *See also* ORS 757.210(a) (providing that the Commission shall conduct a hearing upon a complaint challenging a proposed rate, with the exception that "no hearing need be held if the particular rate change is the result of an automatic adjustment clause.")

The Commission already decided this matter on page 8 of Order No. 10-488: "The IRP process [is] the appropriate venue for determining when a utility is resource sufficient or deficient."[31] OneEnergy recommends the Commission sustain its decision in Order No. 10-488.

4. ***Price Adjustments for Specific QF Characteristics***

4.A. Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology?

Integration charges should only apply to wind until utilities quantify non-wind integration costs and such costs are vetted through a public process. Solar integration costs are unstudied and likely insignificant due to the very low level of solar penetration. Utilities have the burden to justify their avoided costs and have, to date, provided no evidence of integration costs from solar generation. OneEnergy/100, Eddie/32-33.

PGE recommends using a utility-developed solar integration study in its IRP, which PGE acknowledges has not yet been conducted. PGE/300, Macfarlane-Morton/7-8. Idaho Power has not requested a solar integration charge. PacifiCorp proposes to impose the wind integration charge from its 2012 Wind Integration Study. PacifiCorp's Pre-Hearing Memorandum at 8. PacifiCorp argued that the cost to integrate solar "could be equal to or greater than wind integration" because solar is subject to rapid fluctuations during peak ours, thus requiring the utility to retain reserve and ramping reserve during peak hours. PAC/300, Dickman/33. In response to a data request for explanation of the basis for these factors, PacifiCorp explained that it "did not perform any studies to quantify the impact of these factors on integration costs." OneEnergy/407. Mr. Dickman's speculation does not carry PacifiCorp's burden of proof. Order No. 05-871 at 12 n.9 (A "a bald assertion made in testimony" is of "limited use and should be

[31] *Investigation into determination of resource sufficiency, pursuant to Order No. 06-538*, Docket No. UM 1396, Order No. 10-488 (2010).

better supported with evidence…”). The cost of solar integration has not been through the IRP process. RNP/100, Lindsay/9-10. Furthermore, an integration charge would be premature because PacifiCorp has only 2 MW of interconnected solar PV in Oregon. OneEnergy/407. RNP witness Mr. Lindsay notes four differences between wind and solar integration requirements: (1) solar’s more accurate forecasting, (2) greater smoothing of solar’s variability from geographic diversity, (3) lower correlation of solar with existing variable generation, and (4) generation only during daylight hours. RNP/100, Lindsay/8. In short, wind integration is a poor proxy for solar integration. Until studies are conducted and subject to public review, no integration charge should be imposed on solar.

PacifiCorp contends that an integration charge is consistent with Order No. 11-505. Idaho Power similarly contends that a capacity adjustment is consistent with Order No. 11-505. However, it is a stretch of Order No. 11-505 to conclude that the Commission intended to upset the simplicity of published rates established in UM 1129 with adjustments for specific resources. In fact, in Order No. 11-505, the Commission declined “Idaho Power’s and ICNU’s recommendation to derive avoided costs for each type of renewable resources.” In other words, the Commission rejected in Order No. 11-505 just the types of adjustments the utilities and Staff are now proposing.

4.C. How should the seven factors of 18 C.F.R. § 292.304(e)(2) be taken into account?

In UM 1129 the Commission strived to balance the benefits of standard agreements against the risk of inaccuracy (when viewed on a case-by-case, as opposed to system-wide, basis). The Commission approved a Standard Contract and a Non-Standard Contract. QFs electing the Standard Contract are permitted to elect from four available pricing options; no other changes are permitted by either the QF or the utility. Order 05-584, at 39. QFs electing the Non-

Standard Contract receive a standard form of contract with up to seven pricing adjustments tailored to the specific QF. The adjustments are the only adjustments allowed[32], and they are balanced in the sense that some tend to increase the avoided cost price while others tend to decrease it. Adjustments for fossil fuel price risk, smaller capacity increments and shorter lead times (a/k/a "lumpiness"), and avoided transmission and distribution upgrades, if any, always increase the avoided cost.[33] Adjustments for line loss and reliability could be positive or negative depending on the characteristics of the QF compared to the proxy resource.[34] Adjustments for dispatchability and for integration always reduce the avoided cost:

Adjustments to the Standard Avoided Cost (and their net effect on rates "+/-")		
Standard Contract (Order No. 05-584)	Non-Standard Contract (Order No. 07-360)	Standard Contract as proposed by Staff[35]
Pricing Option (fixed price, deadband, gas market, index)	Reliability (+/-) Dispatchability (-) Fossil fuel price risk (+) Lumpiness (+) Integration (wind only) (-) Line losses (+/-) Avoided T&D upgrades (+)	Capacity Contribution (-) Integration (wind) (-)

Staff has proposed to reduce the price in the Standard Contract to account for dispatchability[36] and integration costs in order to "address an existing mismatch between the value of purchase from QFs and avoided cost payments made to QFs".[37] Staff gives no clear explanation why it thinks only downward adjustments are warranted. It would be equally logical

[32] Order No. 07-360 at 16.

[33] *See* Order No. 07-360 at 22 (lumpiness), 23 (fossil fuel risk), 27 (avoided T&D upgrades).

[34] *Id*. at 18 (reliability), 26 (line losses).

[35] Staff/100, Bless/2.

[36] In Order No. 07-360, the Commission defined "dispatchability" as "the flexibility to adjust the output of a generating resource or contract to changing market conditions." *Id*. at 19. Under this adjustment factor, the utility may presumably adjust QF prices downward if the QF's peak hour capacity contribution is lower than the peak hour capacity contribution of the proxy resource. In this proceeding, parties refer to this adjustment as a "capacity contribution" adjustment.

[37] Staff/100, Bless/2.

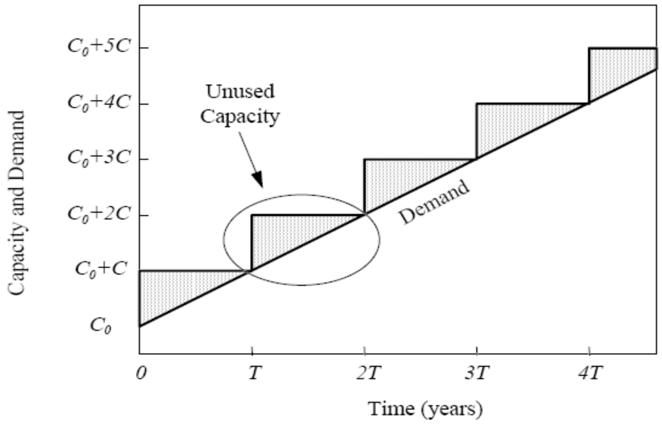
(and equally unfair) to *increase* the Standard Contract rates by adjusting only for fossil fuel price risk, lumpiness, and avoided T&D upgrades. Staff's proposal poses a practical problem as well: it would make the Standard Contract so unattractive that intermittent QFs are likely not to use it. Most QFs would fare better with the Non-Standard Contract, under which the QF may receive upward price adjustment for reduced fossil fuel price risk,[38] lumpiness benefits, and avoided transmission and distribution upgrades.

Benefits of QF generation that offset capacity and integration costs include:

- **Smaller capacity increments and shorter lead times, a/k/a "lumpiness"**. In Order No. 07-360 at 22, the Commission directed parties to account for lumpiness in non-standard agreements if they can establish a practical and reasonable way to do so. Smaller capacity increments and shorter lead-times of QFs smooth the "lumpy" addition of capacity in relatively large increments that utilities tend to make. CREA/200, Reading 25-28; OneEnergy/100, Eddie/10-15. The United States Department of Energy, in a 2007 study mandated by the Energy Policy Act of 2005, concluded that "there can be economic benefits related to generation investment deferral that are directly attributable to distributed generation." OneEnergy/100, Eddie/10-11.

[38] In its 2011 IRP, PacifiCorp assigned a risk reduction benefit of non-fossil fueled resources of $14.98/MWh, a lumpiness benefit of $16.69/MWh, and deferred transmission and distribution benefits ranging from $1.75 to $16.63/MWh. CREA/200, Reading/27.

Distributed Generation Can Reduce Unused Capacity[39]



OneEnergy and CREA submitted evidence in this proceeding documenting several published, peer-reviewed methodologies for calculating such savings. OneEnergy/100, Eddie/10-11; CREA/200, Reading/25-26. They also submitted evidence that PacifiCorp calculates, in its IRP, the lumpiness savings associated with its purchases of non-dispatchable energy efficiency. Eddie/12-15; CREA/200, Reading/27-28.

- **Dispatchability (curtailability).** OneEnergy proposed that QF projects curtailable on demand should receive a higher Standard Avoided Cost Rate. OneEnergy/200, Eddie/4. Utilities often lament that being forced to purchase QF output poses operational constraints and yet none of the utilities in this proceeding have responded to OneEnergy's proposal. *See, e.g.,* May 23, 2013 Cross-Examination Hearing—UM 1610, pp. 108-09 (Griswold).

- **Avoided line losses for distribution-interconnected QFs under 3 MW**. OneEnergy and others presented evidence that generators connected directly to the distribution system avoid transmission line losses above and beyond transmission-interconnected generators because their output is typically used locally before reaching the transmission system. OneEnergy/100,

[39] *The Potential Benefits of Distributed Generation and Rate-Related Issues that may Impede Their Expansion, United States Department of Energy*, p. 3-16 (February 2007) (http://www ferc.gov/legal/fed-sta/exp-study.pdf) (excerpted from Hoff, T. E., Wenger, H. J. and B. K. Farmer, 1996, "Distributed Generation: An Alternative to Electric Utility Investments in System Capacity" Energy Policy 24(2): 137-147), appears in OneEnergy/100, Eddie/11.

Eddie/3-37; ODOE/400, Carver/5-6. Southern California Edison has estimated losses on its transmission system of 4.4%; the Northwest Power and Conservation Council estimated WECC-wide transmission system losses of 3.9%. OneEnergy/200, Eddie/18. Each of the utilities admits that it has the present capability to model avoided system losses associated with distribution-interconnected generators but has not yet done so. OneEnergy/200, Eddie/17. A 3.9% upward adjustment to Avoided Cost prices of QFs of 3 MW or less interconnected to the distribution system of the utility purchasing its net output is just and reasonable and better represents reality than the current 0% adjustment. OneEnergy/100, Eddie/35.

● Reduced fossil fuel risk of QF renewables and avoided CO_2 costs compared to the fossil-fueled proxy resource. In page 5 of Order No. 12-396, the Commission found that avoided CO_2 costs, avoided fuel price volatility, and avoided line losses are legitimate components of the value associated with QFs in the context of the Solar PV Pilot Program; the utilities do not collaterally attack the Commission's finding in this proceeding.

Burden of persuasion. The record provides substantial evidence that the above benefits that QFs provide are real and that they are not accounted for in the Standard Contract. OneEnergy has proposed a definite adjustment with a specified value in only one instance—avoided line losses—because quantifying the remaining QF benefits requires the cooperation of the utilities. While the utilities have studied wind integration costs and differences in capacity contributions from different resources, none of the utilities has studied line loss savings from distributed generation, lumpiness related QF savings, or savings related to having the right to curtail a QF. Nor do they apply to QF avoided costs the benefits of avoided fuel volatility price risk and avoided CO_2 regulatory price risk. The QFs should not be harmed by the utilities' choice to not study benefits of QFs. If the Commission is inclined to include capacity and integration adjustments to the Standard Contract, it should do so only if and when the utilities study and quantify the affects of lumpiness, avoided line losses, fuel price volatility, etc. on their avoided costs. Where, as here, the utilities are the only parties that can adequately quantify these effects and have chosen to quantify only the effects that would boost their own profit, the Commission may find that the utilities' have not met their burden to prove their proposed changes are just and reasonable.[40] The only barrier to establishment of a practical and reasonable methodology for valuing all of the QF benefits above is an order from the Commission directing the utilities to do so. Either all seven of the adjustment factors should be evaluated and adjusted (if warranted) at the same time, or else the framework established in Docket No. UM 1129 should be retained without Staff's proposed changes.

5. <u>Eligibility Issues</u>

5.A. Should the Commission change the 10-MW cap for the standard contract?

No. The Idaho Public Utilities Commission ("Idaho PUC") recently reduced the capacity limit for standard rates from 10 average-MW to 100 kW for wind and solar.[41] PGE and Idaho Power ask the Commission to follow suit.[42] PacifiCorp asks for the limit to be lowered to 3 MW.[43] Idaho state's circumstances that led to the reduction are in no way comparable to Oregon's circumstances. In Idaho, wind QFs of over 25 MW and sited one mile apart were

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[40] *See Midland Cogeneration Venture Ltd. Partnership v. Pub. Serv. Comm'n*, 199 Mich. App. 286, 325 (1993) ("Any corporation interested in making a profit will be only too glad to provide better, more detailed information to the PSC, including information obtained from an affiliate, in an effort to justify the highest supportable rate of return for its investors. If an affiliate, joint venture, or subsidiary such as MCV is not cooperative, the PSC may draw an adverse inference or, equivalently, find that the parent utility has thereby failed to carry its burden of proof that a higher rate of return should be allowed.").

[41] *In the matter of the Commission's Investigation into Disaggregation…*, Idaho PUC Case No. GNR-E-11-01, Order No. 32262, 9 (2011).

[42] PGE's Prehearing Memorandum at 9 (or 1 MW if Staff's adjustments are not implemented); Idaho Power's Pre-Hearing Memorandum at 12.

[43] PacifiCorp's Pre-Hearing Memorandum at 11.

eligible for published rates.[44] In Oregon, published rates are limited to QFs of 10 MW or less separated by at least five miles. In Idaho, the Idaho PUC decided not to attempt to prevent disaggregation prior to 2011.[45] Oregon has a safeguard against disaggregation that Idaho does not. Oregon's Partial Stipulation provides a dispute resolution process in the event a utility believes a QF is attempting to disaggregate that allows for the dispute to be referred to the Commission long before the QF may incur a legally enforceable obligation.[46] The record does not substantiate a need to reduce the eligibility limit. Even if one takes into account the QFs PacifiCorp claims belong to large disaggregated projects, PacifiCorp has averaged less than 30 MWs per year of new QF capacity since Order No. 05-584. *See* PAC/200, Griswold/32. QF activity in Oregon does not compare to the activity in Idaho that led to the capacity limit reduction. In sum, lowering the eligibility limit in Oregon is not warranted.

Two minor refinements to the cap are justified based on the record. First, a subclass of QFs (those 3 MW or less directly interconnected to the purchasing utility's distribution system) should have additional options in the standard contract (tilted prices, 25-year fixed term, 3.9% line loss adder) in recognition of special benefits they provide. OneEnergy/100, Eddie/4-6, 18, 33-41; OneEnergy/200, Eddie/3, 16. Second, the Commission should clarify that the eligibility cap applies to alternating current AC (as opposed to DC) capacity of PV solar QFs. In recognition of the energy lost by converting direct current photovoltaic output to alternating

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[44] *See, e.g., In the Matter of the Application of PacifiCorp dba Rocky Mountain Power for a Determination Regarding a Firm Energy Sales Agreement between Rocky Mountain Power and Cedar Creek Wind, LLC…*, Idaho PUC Docket Nos. PAC-E-11-01, PAC-E-11-02, PAC-E-11-03, PAC-E-11-04, and PAC-E-11-05, Order No. 32419 (2011).

[45] *In the Matter of Idaho Power Co.'s Petition… to Clarify the Rules Governing Entitlement to Published Avoided Cost Rates*, Idaho PUC Docket No. IPC-E-07-04, Order No. 30415 (2007).

[46] *Partial Stipulation*, Docket No. UM 1129, Order No. 06-586; *see also* Order No. 06-538 (approving Partial Stipulation). To the best of OneEnergy's knowledge, no utility has exercised its right to refer alleged disaggregation to the Commission. As discussed *infra* in Issue 5.B, OneEnergy supports PacifiCorp, PGE, and Staff's proposal to eliminate the passive investor exception to the Partial Stipulation.

current, for purposes of eligibility, the "nameplate capacity" of photovoltaic QFs should be 0.85 times the maximum DC output (kWdc) from the project. OneEnergy/200, Eddie/3. This ratio is consistent with the ratio set by the Commission in Oregon's Solar PV Pilot Program. OAR 860-084-0040(2).

5.B. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract?

OneEnergy supports strong rules preventing disaggregation and believes modifications to, and clarification of, the passive investor exception could eliminate any perceived loophole in the current rules. OneEnergy/100, Eddie/7-8. OneEnergy also notes that the utilities have the right, under the Partial Stipulation adopted in Docket No. UM 1129, to refer a dispute regarding disaggregation to the Commission rather than offer contracts to disaggregated QFs. *Id*. OneEnergy disagrees with Staff's position that the Commission should not recognize the benefits of QFs 3 MW or less due to risks of disaggregation. Staff/200, Bless/25. Disaggregation can be prevented more accurately and appropriately through changes to the Partial Stipulation. OneEnergy supports PacifiCorp's proposal to eliminate the passive investor exception to the Partial Stipulation. OneEnergy/100, Eddie/8; PAC/200, Griswold/25).

5.C. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?

No. This is an overly broad approach to preventing abuse of standard rates by disaggregators. The Partial Stipulation, with PacifiCorp's proposed modification to the passive investor exception, can prevent disaggregation without discriminating against solar and wind projects. OneEnergy/100, Eddie/7-8.

6. Contracting Issues

6.B. When is there a legally enforceable obligation?

PGE's proposal (PGE/100, MacFarlane-Morton/23) that QFs be online within one year of executing a power purchase agreement should be rejected. As discussed in the "applicable legal standard" section on pages 4 and 5 of this brief, the party seeking to change the *status quo* generally has the burden to demonstrate that its proposed change is just and reasonable, and not unduly discriminatory or preferential.[47] To reach a determination on whether PGE's proposal is just and reasonable**,** the Commission should look to the record as a whole and make a determination based on the preponderance of the evidence.[48]

PGE has failed to provide any evidence in support of its proposed one-year rule. PGE has merely speculated that without the proposed one-year rule, QFs can "game the system" and secure rates years ahead of a commercial online date which will prove to be higher rates than will prevail when the QF project becomes operational. PGE/100, MacFarlane-Morton/23. PGE also theorizes that the one-year rule will not adversely impact a developer's ability to obtain financing for a proposed QF development. PGE/300, MacFarlane-Morton/21-22. But it is just as easy for developers to assert that allowing QFs to secure PPAs more than one year before commercial operation is essential to securing project financing, is beneficial to purchasing utilities because it allows them better forecasting of future generation resources that will be under contract, and that it does not unfairly advantage QFs because after a QF enters into a fixed-rate contract, the purchasing utility's avoided cost rates might just as well increase as decrease.

[47] *Idaho Power Co.*, 137 FERC ¶ 61,235, 62,512 (2011); *Petition of Inquiry into the Rates Paid by Houston Lighting And Power Co.*, 12 Texas P.U.C. Bulletin 795.

[48] *In the Matter of PGE Co. 2012 Annual Power Cost Update Tariff (Schedule 125),* OPUC Docket No. UE 228 Order No. 11-432 (2011).

PGE has the burden of proof to provide evidence to support its contention that the one-year rule will not frustrate QFs' ability to obtain project financing. PGE has provided no evidence at all in support of its proposed one-year rule. See Order No. 05-871 at 12 n.9 ("[A] bald assertion made in testimony" is of "limited use and should be better supported with evidence…"). The Commission should therefore reject PGE's proposal.

6.I. What is the appropriate contract term? What is the appropriate duration for fixed prices?

QFs 3 MW or less directly connected to the purchasing utility's distribution system should have the option to elect up to a 25-year fixed-price term provided that the QF has site control for a term equal to or greater than the term of the PPA. OneEnergy/200, Eddie/3, lines/5-11; OneEnergy/200, Eddie/16, 18. Consistent with the 8% small-scale renewable goal in ORS 469A.210, limiting this option to QFs interconnected to the purchasing utility limits its availability to QFs located within Oregon.[49] Limiting this option to distribution level QFs 3 MW or less further encourages small-scale, distributed generation.

On page 19 of Order No. 05-584, the Commission found that "our fundamental objective is to establish a maximum standard contract term that enables eligible QFs to obtain adequate financing, but limits the possible divergence of standard contract rates from actual avoided costs." Staff recommends no change because the discussion "has not really changed" since the Commission set the fixed-rate term at 15 years. Staff Prehearing Memorandum at 14. OneEnergy disagrees. Even during the tenure of the Oregon Business Energy Tax Credit (BETC) QF development in Oregon was modest. For example, PacifiCorp averaged less than 30 MW of new QF capacity a year since Order No. 05-584. *See* PAC/200, Griswold/32 ("Since Order No. 05-

[49] *Tumbleweed Energy II, LLC v. Idaho Power Co.*, Docket No. UM 1552, *Western Desert Energy, LLC v. Idaho Power Co.*, Docket No. UM 1553, Order No. 12-083 (2012) (holding QF may interconnect with purchasing utility in one state and compel utility to purchase generation in another state).

084 [sic], the Company has executed standard PPAs with 38 new construction QF projects totaling 195.5 MWs.").

OneEnergy's analysis of fixed-rate terms of 15 years and 25 years for a hypothetical 1-MW solar QF in Oregon shows that such QFs will have difficulty financing their projects with only a 15-year PPA. OneEnergy/200, Eddie/21-23. The analysis shows an increased internal rate of return (from 7.72% to 11.01%) and net present value (-$99,704 to $4,775) with a 25-year PPA. *Id*. Increasing the term of the PPA would not increase the PPA purchase prices above avoided costs but *would* further the Commission's objectives, above, as well as the state's policy of promoting community renewable generation in ORS 469A.210.

Idaho Power and PacifiCorp propose to lower the fixed-rate term to 10 years. The utilities offer two justifications: (1) that QFs would not be harmed; and (2) that 10 years more fairly balances price risk. Idaho Power's Prehearing Memorandum at 15; PacifiCorp's Prehearing Memorandum at 15. PacifiCorp asserts that its "experience shows that a shorter term for the fixed-price would not adversely affect the QFs [sic] ability to secure financing." PacifiCorp's Prehearing Memorandum at 15. In footnote 85 accompanying the quoted text, PacifiCorp claims that in its experience "most [new QF projects] elected for shorter-term contracts". *Id*. (citing PAC/200, Griswold/32-33). In fact, PacifiCorp's own testimony proves the opposite. According to PacifiCorp's testimony, 57% of new QFs elected contracts terms longer than 15 years, and a full 78% elected terms of longer than 10 years. PAC/200, Griswold/33. QFs prefer longer fixed-rates terms in part because loan terms are limited to the fixed-rate term of the PPA. ODOE/200, Elliot/10-11. Shorter loan terms make for higher monthly loan payments for the QF and would result in QF developers not going forwards with projects. *Id*.

Idaho power also asserts that a 10-year term would "[n]ot necessarily" harm QFs. *Id*. at 39. Idaho Power contends that QFs could still contract for their full economic life "as long as PURPA still exists". *Id*. However, the *possibility* of renewing a contract *at unknowable rates* and "as long as PURPA still exists" does not provide adequate certainty for obtaining project financing. ODOE's Pre-Hearing Memorandum at 10 ("Shorter contract terms could result in small QF projects becoming non-financeable."). Idaho Power and PacifiCorp have not provided substantial evidence showing that reducing the fixed-rate term would not harm QFs. In fact, PacifiCorp's testimony shows that a 10-year fixed rate would preclude 78% of the new QF contracts PacifiCorp has entered into since Order No. 05-584.

Idaho Power argues that a 10-year term would more equitably share market price risk. Idaho Power/400, Stokes/38-39; *see also* PAC/200, Griswold/33. First, 25-year terms are common with renewable projects. OneEnergy/200, Eddie 18-19 (identifying five recent 25-year PPAs between PGE or Idaho Power and renewable projects, including three solar projects). A shorter term for QFs would be discriminatory. Second, the utilities fail to acknowledge the benefits to the utility of long-term fixed rates, which do not fluctuate with gas prices or during crisis such as the 2001 energy crisis. The Commission recognizes the principle that long-term fixed contracts are a tool for mitigating price risk. *PGE 2012 Annual Power Cost Update Tariff (Schedule 125),* Order No. 11-432, 10 (2011) ("[W]e agree with PGE's expert witness that a *long-term risk such as PGE's [2012 net open position] can be managed through long-term contracts* and shaped as the prompt year approaches and shorter-term products become more liquid." (emphasis added)). As discussed above in Issue 4.C, avoided cost rates do not include a fuel price risk adjustment to account for the risk-management benefit to the purchasing utility of fixed rates divorced from gas price fluctuations.

The utilities' conclusion that a shorter fixed-rate term would not harm QFs is simply not credible. The utilities' arguments ignore the long-term commitments utilities negotiate for renewable projects and ignore the fuel price risk mitigation of fixed rates. With gas prices at a historic low, now is the time to *increase* the fixed-rate term. OneEnergy's Pre-Hearing Brief at 12-13 (proposing fixed rates for 25 years for projects 3 MW or less directly connected to distribution system); ODOE's Pre-Hearing Memorandum at 10-11 (proposing fixed rates for 20 years for projects 3 MW or less directly connected to distribution system); CREA's Prehearing Legal Brief at 15 (proposing fixed rates for 20 years or longer, especially for "very small QFs"); RNP's Prehearing Memorandum at 5 (proposing fixed rates for at least 20 years, "particularly at a time like this when the upside risk associated with gas and market forecasts is greater than the downside risks."). OneEnergy proposes fixed-rate terms of up to 25 years for QFs of 3 MW or less directly connected at the distribution level.

IV. CONCLUSION

Taken together, the number of issues raised by the parties is daunting. One group of issues regards implementation of the Renewable Avoided Cost. Another group of issues would make incremental changes to existing rules. These issues either fill in a gap in the original UM 1129 framework or adapt the UM 1129 framework to function as intended in light of conditions that have evolved since the Commission implemented the framework. A third group of issues implicates significant policy changes by the Commission. Changes in the third group are foundational because they add a level of particularity that the Commission already considered and rejected in UM 1129. OneEnergy believes that all of these issues are important but not all issues are ripe for resolution at this time.

A. Issues regarding implementation of the Renewable Avoided Cost. In Order No. 11-505 the Commission found that implementation of the renewable avoided cost required an evidentiary record to derive utility-specific avoided cost rates for renewable resources. UM 1610 has provided parties such an opportunity to conduct discovery and propose changes to PGE's and PacifiCorp's compliance filings. Renewable Avoided Cost issues ripe for decision include: (a) the scope of costs comprising the "full avoided cost" of the renewable resource (e.g., incremental transmission costs of PacifiCorp's Wyoming wind resource); (b) applicability of capacity adjustment factors; (c) applicability of integration charges; (d) the definition of which environmental attributes transferred to the utility during the deficiency period; and (e) whether OAR 860-022-0075 needs revision. OneEnergy urges the Commission to implement the renewable avoided cost rates for PacifiCorp and PGE as soon as possible.

B. Issues re the Existing UM 1129 Framework. OneEnergy also supports resolution of issues that update or fill gaps in the existing framework. Gap filling issues include: (f) the scope of costs comprising the "full avoided cost" of the CCCT resource (e.g., gas firming costs); (g) the definition of "nameplate capacity" as applied to solar QFs; (h) crediting small QFs connected to the distribution system with avoided line losses; (i) clarification of when a QF may unilaterally create a legally enforceable obligation; and (j) the availability of tilted or levelized prices. Changes proposed due to evolving conditions include: (k) changes to the frequency of updates to the avoided cost in light of experienced volatility in market prices; (l) changes to the "passive investor exception" rule in order to close a perceived loophole; (m) and changes to the maximum length of standard contract for QFs 3 MW and under in light of changed economic realities. These policy decisions can be based on the evidence in the record and can be implemented with minimal process within the existing framework. These changes are timely right now while small developers can use the federal business energy investment tax credit, which is scheduled to shrink from 30% to 10% in 2017 (with respect to solar PV).

C. <u>Foundational changes to the UM 1129 Framework</u>. OneEnergy opposes foundational changes proposed by the utilities because the need for such changes has not been established. Alternatively, foundational changes should be implemented, if at all, after the utilities' and the QFs' proposals are more fully developed and can be considered simultaneously. Foundational issues include the utilities' proposals to: (n) abandon the Oregon avoided cost method; (o) adopt resource-specific capacity values; (p) deduct resource specific integration charges from the standard offer; and (q) lower the standard rate cap; and the QFs' counterproposals to: (r) add avoided transmission and distribution costs; (s) add avoided integration costs (t) add avoided fuel price volatility; (u) add avoided CO_2 costs; and (v) add lumpiness benefits. The utilities have not met their burden of justifying why the Commission should abandon the Oregon avoided cost method, adopt resource specific capacity values, add integration charges, or reduce the eligibility cap. Likewise, the cost impacts of the foundational changes the QFs propose have not been adequately studied (in part because they require cooperation between the QFs and the utilities). Rather than risk breaking a system that has worked well by making piecemeal changes, it would be safer to set over these issues until they have been studied together and then implemented, if at all, in a balanced fashion.

Dated this 17th day of June 2013.

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I HEREBY CERTIFY that, on the 17th day of June 2013, I served a true and correct copy of the foregoing *OneEnergy, Inc.'s Post-hearing Brief (Phase I)* in OPUC Docket No. UM 1610 on the following named persons/entities by electronic mail.

DATED this 17th day of June 2013.

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