BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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| IN THE MATTER THE PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation Into Qualifying Facility Contracting and Pricing | CASE NO. UM 1610<br>PHASE II<br><br>PREHEARING LEGAL BRIEF OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION |

TABLE OF CONTENTS



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# I. INTRODUCTION

Pursuant to the Administrative Law Judges' ("ALJ") procedural ruling issued on March 26, 2015 ("March 26th Ruling"), the Community Renewable Energy Association ("CREA") hereby respectfully submits this prehearing legal brief to the Public Utility Commission of Oregon ("Commission" or "OPUC"). This brief addresses each of the issues set forth in the March 26th Ruling, which relate to contract terms and rates available to qualifying facilities ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA").

CREA is comprised of several Oregon counties which provide active participation through their county commissioners, including the counties of Sherman, Wasco, Gilliam, Harney, Hood River, Morrow, Polk, Union, Wheeler, Curry, and Wallowa. CREA/500, Skeahan/2. In addition to these counties, CREA's current membership includes the Mid-Columbia Council of Governments, Columbia Gorge Community College, and 25 irrigation districts, businesses, individuals and non-profit organizations who have interests in a viable community renewable energy sector for Oregon. *Id.*

Although initially enacted in 1978, PURPA remains highly relevant in Oregon because there is no other significant opportunity to develop cost-effective renewable energy projects in Oregon's monopoly utility market place. *See* CREA/500, Skeahan/2-7. Thus, CREA strongly supports maintaining and strengthening the Commission's policies implementing PURPA, 16 U.S.C. § 824a-3 *et seq.*, and Oregon's mini-PURPA statute, ORS 758.505 -.555. As explained with regard to the specific issues discussed below, CREA urges the Commission to resolve the issues in Phase II of this docket in a manner that provides meaningful opportunities for cost-effective QF projects to sell their output to the utilities at the utilities' avoided costs.

## II. BACKGROUND

Section 210 of the PURPA "seeks to *encourage* the development of cogeneration and small power production facilities." *FERC v. Mississippi*, 456 U.S. 742, 750 (1982) (emphasis added); 16 U.S.C. § 824a-3(a). Congress found this to be necessary because "traditional electricity utilities were reluctant to purchase power from, and to sell power to, the nontraditional facilities." *Mississippi*, 456 U.S. at 750. Congress further determined these facilities need to be encouraged because "cogenerators and small power producers are different from electric utilities, not being guaranteed a rate of return on their activities generally or on the activities vis-a-vis the sale of power to the utility and whose risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable." *Amer. Paper Institute, Inc. v. Amer. Elect. Power Serv. Corp.*, 461 U.S. 402, 414 (1983) (internal quotation omitted). PURPA directs the Federal Energy Regulatory Commission ("FERC") to establish regulations to implement the requirement that electric utilities must purchase electric energy from QFs. 16 U.S.C. § 824a-3(a)(2). In turn, PURPA requires state regulatory authorities to implement FERC's regulations. *Mississippi*, 456 U.S. at 751; 16 U.S.C. § 824a-3(f); 18 C.F.R. §§ 292 *et seq*.

Oregon law itself declares that it is "the policy of the State of Oregon to . . . [i]ncrease the marketability of electric energy produced by qualifying facilities located throughout the state for the benefit of Oregon's citizens" and to "[c]reate a settled and uniform institutional climate for qualifying facilities in Oregon." ORS 758.515(3). More recently, Oregon enacted its renewable portfolio standard ("RPS"), which requires utilities to obtain a certain percentage of their load requirements with specified "renewable energy sources." ORS 469A.005-.300. The RPS further provides, "The Legislative Assembly finds that community-based renewable energy projects . . . are an essential element of Oregon's energy future." ORS 469A.210. The RPS therefore "declares that it is the goal of the State of Oregon that by 2025 at least eight percent of Oregon's retail electrical load comes from small-scale renewable energy projects with a generating capacity of 20 megawatts or less." *Id.* The law even mandates that all executive department agencies, including the OPUC, "*shall* establish policies and procedures promoting the [eight percent] goal declared in this section." *Id.* (emphasis added).

## III. ARGUMENT

Phase II of this docket will resolve several important details regarding the OPUC's implementation of PURPA's purchase obligation. As noted above, federal and state law direct that the OPUC should do everything within its power to *encourage* QFs through its implementation of rates, contract terms, and contracting policies for QFs. The remainder of this brief is organized in the order of the issues as listed in the March 26th Ruling.

### A. Issue 1: *Who owns the Green Tags during the last five years of a 20-year fixed price PPA during which prices paid to the QF are at market?*

This issue arises because PacifiCorp insisted during workshops that it should receive the green tags, or renewable energy certificates ("RECs"), associated with QF generation at a time when the utility pays the QF for "brown power." More recently, Portland General Electric Company ("PGE") has also asserted it would like to receive a renewable QF's RECs without paying for renewable energy. As explained below, the Commission should clarify that during all periods that the renewable QF is paid a rate other than the full renewable proxy rate, the QF retains ownership of the RECs.

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### 1. Background on Ownership of RECs In Renewable Rate Contracts.

Under the Commission's renewable avoided cost rate option, the utility pays the QF a renewable rate for electricity bundled with RECs. CREA/500, Skeahan/8 (quoting Order No. 11-505 at 9). The Commission's order establishing the renewable rate expressly states that the QF should retain ownership of the RECs during the renewable resource sufficiency period when the QF is paid a market price. *Id.* PacifiCorp and PGE currently offer the renewable avoided costs for a maximum period of 15 years after QF's online date.[1] CREA/500, Skeahan/9. QFs have the option to enter into a contract with a length of up to 20 years, but are only paid a market price for output delivered in the last five years (years 16 through 20). *Id.* The rationale and statements of Order No. 11-505 indicate that the QF retains ownership of the RECs when it is paid a market price. *Id.* But the order does not expressly state who owns the RECs in years 16 through 20 of a 20-year contract. *Id.*

### 2. The QF Should Own the RECs Anytime It Is Not Paid the Renewable Proxy Rate.

The Commission should confirm that the QF will retain ownership of the RECs during years 16 to 20 of a renewable-rate contract when it is paid a market-based price. The QF is not paid a renewable rate in years 16 through 20. The market-based price is not a price for green power; it is a price for undifferentiated brown power. CREA/500, Skeahan/9-10. PacifiCorp and PGE propose that the utility should obtain ownership of the QF's RECs without paying a renewable-based price in years 16 through 20. PAC/1000, Griswold/4-7; PGE/500, Macfarlane-Morton/4-6. But the utilities should not obtain a product for which they do not pay the QF. As Staff's witness, Ms. Brittany Andrus, explains, under Order No. 11-505, the "Commission's

[1] The renewable rate option does not currently apply to Idaho Power.

rationale links the QF's obligation to transfer RECs to the receipt of prices designed to compensate for the value of the RECs." Staff/600, Andrus/4. Alternatively, based on this logical reasoning, if the Commission believes that PacifiCorp and PGE should be allowed to obtain the RECs in years 16 through 20, the Commission should require that the utility pay the renewable proxy rate to the QF during that period of time. CREA/500, Skeahan/10.

## B. Issue 2: *Should avoided transmission costs for non-renewable and renewable proxy resources be included in the calculation of avoided cost prices?*

The Commission should clarify its policy on inclusion of transmission costs in the avoided cost rates calculated for on-system proxy resources. Otherwise, the utilities will be offering less than the full avoided costs at times when the proxy resource is an on-system resource that would require significant transmission investments.

### 1. Background on Transmission Costs of Proxy Resources.

Federal and state law require that the avoided cost rates must reflect the full avoided costs. *Amer. Paper Institute, Inc.*, 461 U.S. at 412-17; ORS 758.525(2). A state commission should include the costs of avoided transmission in calculation of the avoided cost rates if the QF will allow the utility to avoid those transmission costs. *Calif. Pub. Util. Commn.*, 133 FERC ¶ 61,059, P 31 (2010). Accordingly, in Phase I, the Commission confirmed that "if the proxy resource used to calculate a utility's avoided costs is an off-system resource, the costs of third-party transmission are avoided, and are therefore included in the calculation of avoided cost prices." Order No. 14-058 at 17. The Commission assumed that, "[i]f the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs . . . ." *Id.* Thus, the Phase I order does not address the situation where the proxy resource is on-system and will require transmission upgrades to deliver the output to load. Yet an on-system proxy resource can impose transmission costs on a utility and its customers, such as when a proxy resource will clearly require the utility to incur costs for upgrades to network transmission on the utility's own system. *See* CREA/500, Skeahan/12; Staff/600, Andrus/6-7.

### 2. The Commission Should Clarify that Transmission Costs of On-System Proxy Resources Will Be Included in the Avoided Cost Rates.

Excluding transmission costs required to bring generation output from a utility proxy to load undermines the very concept of *avoided* cost. CREA/500, Skeahan/12. Doing so is also contradictory to the policy that on-system QFs must pay (or receive reduced avoided cost rates) for third-party transmission costs associated with moving their output between PacifiCorp's load pockets. CREA/500, Skeahan/20-21. Assigning transmission costs to on-system QFs but failing to assign transmission costs to on-system proxy resources would result in discriminatory avoided cost rates in violation of PURPA. *See* 16 U.S.C. § 824a-3(b)(2) (avoided cost rates "shall not discriminate against qualifying cogenerators or qualifying small power producers"); ORS 758.525(4) (same).

Pursuant to ORS 756.568, the Commission should therefore amend Order No. 14-058 at page 17, by clarifying, as follows:

> If the on-system proxy resource cannot be designated a Network Resource at its full capacity without transmission upgrades and without a de-rating or curtailing other Network Resources, then the cost of transmission upgrades necessary to make it a Network Resource should be included in the avoided cost prices.

OneEnergy/400, Eddie/2-3.[2] Although Staff would not mandate this test in every case, Staff agrees that this test could inform the case-by-case determination of whether any particular proxy will require on-system transmission costs. Staff/600, Andrus/7. The Commission should clarify

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[2] Although CREA proposed a slightly different formulation of this proposed clarification in its testimony, it is adopting OneEnergy's test to limit confusion.

Order No. 14-058 and ensure that transmission costs associated with on-system proxy resources are included in the avoided cost rates.

**C. Issue 3:** ***Should the Commission revise the methodology approved in Order No. 14-058 for determining the capacity contribution adder for solar QFs selecting standard renewable avoided cost prices? If so, how?***

**Issue 4:** ***Should the capacity contribution calculation for standard non-renewable avoided cost prices be modified to mirror any change to the solar capacity contribution calculation used to calculate the standard renewable avoided cost price?***

The new capacity contribution calculation for both solar renewable and standard (non-renewable) wind and solar rates results in a double discount that under-compensates QFs. Failure to correct this defect in the rate calculation methodology results in a violation of the requirement that QFs be paid a reasonable estimate of the full avoided costs. *Amer. Paper Institute, Inc.*, 461 U.S. at 412-17; ORS 758.525(2).

**1. The Commission Should Correct the Double Discount for Solar Renewable Rates.**

The double discount for solar renewable rates was thoroughly described in the testimony of OPUC Staff, Oregon Department of Energy ("ODOE"), Obsidian Renewables, LLC ("Obsidian"), and OneEnergy, filed during the solar capacity credit portion of this proceeding held in the time between Phase I and Phase II.[3] In response to the Commission's request for additional testimony on this topic in this Phase II, these parties have now thoroughly demonstrated the flaw in the calculation methodology. *See* Staff/500, Andrus/11-20. The Commission should adopt Staff's revised proposal as set forth in painstaking detail in Staff's Phase II testimony. *Id*.

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[3] Additionally, CREA provided briefing at that time, to which we direct the Commission for further explanation.

### 2. The Commission Should Correct the Double Discount for Non-Renewable Rates.

Although double discount was first identified as a defect in calculation of the solar renewable rates, the same mathematical correction must be made with regard to standard (non-renewable) wind and solar avoided cost rates under the new capacity contribution to peak methodology. Staff/500, Andrus/21. In short, "[a]n adjustment to the payment methodology must be made for any resource that does not have an on-peak capacity factor equivalent to that assumed for the thermal resource." *Id.*

The utilities' arguments to the contrary do not withstand scrutiny. *See* Staff/600, Andrus/11-13; Staff/700, Andrus/3-4. Failing to correct the error in the new capacity contribution calculation adopted in Order No. 14-058 would systematically underestimate the actual avoided costs and thereby fail to implement the full avoided cost rule. *Amer. Paper Institute, Inc.*, 461 U.S. at 412-17; ORS 758.525(2).

### D. Issue 5: *What is the appropriate forum to resolve litigated issues and assumptions?*

Oregon law requires the Commission to review and approve avoided cost rate filings to ensure that the rates equal the full avoided costs. The Commission has determined that "avoided cost filings are already subject to suspension and the same investigatory process that any tariff filing may undergo." CREA/600, Skeahan/9 (quoting Order No. 05-584 at 36-37). However, recent disputes necessitate clarification from the Commission on the proper forum to review and approve the rates and clarification as to the proper filing requirements applicable to a utility's avoided cost rate updates.

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### 1. Oregon Law Requires the Commission to Review and Approve the Utilities' Avoided Cost Rates.

The Commission may not simply rubber stamp the utility's calculation of its avoided costs. Rather, Oregon law states "each electric utility shall prepare, publish and file with the Public Utility Commission a schedule of avoided costs . . . . Prices contained in the schedules filed by public utilities shall be *reviewed and approved* by the commission." ORS 758.525(1) (emphasis added). This statute is clear and unambiguous. The Commission must specifically review and approve the proposed inputs and assumptions that result in the avoided cost rates.

### 2. The Commission Should Clarify the Forum and Filing Requirements for Setting Avoided Cost Rates.

CREA submits that there are two reasonable procedural options to review and approve avoided cost rates. First, the Commission could expand the IRP process to allow for a complete review of the avoided costs that will be approved by a Commission order at the time of IRP approval. REC/400, Lowe/13-17. Second, the Commission could implement an expanded contested case that occurs after the approval of the IRP. *Id.* ODOE advocates strongly for the first approach; Staff advocates strongly for the second approach. ODOE/700, Carver/5-7; Staff/500, Andrus/25-26. CREA agrees either approach is reasonable, but also believes that ODOE's proposal will result in more timely approval of the new rates. In either case, however, the utility must have the burden of proof that the avoided cost rates are reasonable because the utility unilaterally selects the inputs and assumptions. *See* REC/400, Lowe/15-16.

Despite the clear legal requirements, PacifiCorp and Idaho Power appear to propose that avoided cost rates should not be "reviewed and approved by the commission," but should instead be unilaterally developed by utilities during an IRP process without meaningful review. *See,* *e.g.*, PAC/900, Drennan/11-12; Idaho Power/900, Allphin/4-6. According to this misguided proposal, utilities could rely on un-reviewed and unapproved inputs in the IRP as the basis to set avoided costs, and no party could challenge those assumptions prior to the time the rates go into effect.[4] Aside from the legal infirmity with this proposal, it is also bad policy. The focus of the IRP is not to set avoided cost rates. CREA/600, Skeahan/8. The Commission should clarify that stakeholders will have the opportunity to challenge the utility's rate calculations.

Additionally, the Commission should require the utilities to include minimum filing requirements ("MFRs") with their avoided cost rate update filings. This will streamline the process of reviewing and approving the new avoided cost rates by reducing the need for discovery in order to understand the basic assumptions included in the rate filing. CREA/600, Skeahan/9. MFRs will allow the rates to go into effect more quickly if they are reasonable as filed. *Id.* However, the Commission still must provide a contested case process to challenge the inputs and assumptions in the rates that appear to be unreasonable from a review of the MFRs. CREA/600, Skeahan/10.

**E. Issue 6: *Do the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?***

CREA recommends that the Commission should adopt the proposal of Mr. Kevin C. Higgins to ensure that QFs receive the full avoided cost rates during the resource sufficiency period. *See* Joint QF Parties/100, Higgins/1-18. As Mr. Higgins recommends, the Commission should compensate renewable and zero-emitting QFs for the avoided costs of planned capital costs to retain existing thermal resources and should correct assumptions in the IRP related to

[4] Notably, PGE appears to acknowledge that basic due process should afford stakeholders the opportunity to challenge the IRP assumptions in some forum. PGE/500, Macfarlane-Morton/8.

existing QFs that are renewing their contracts. *Id.* CREA directs the Commission to the Joint QF Parties' prehearing legal brief, which discusses this issue in detail.

### F. Issue 7: *What is the most appropriate methodology for calculating non-standard avoided cost prices? Should the methodology be the same for all three electric utilities operating in Oregon?*

The Commission should retain its current method of calculating non-standard avoided cost rates because no party has identified any flaws that are resulting from that methodology.

#### 1. The Existing Policy for Calculation of Non-Standard Rates.

For PGE and PacifiCorp, the Commission's current methodology for calculating non-standard avoided cost rates uses the standard rates as the starting point for negotiations and allows for project-specific adjustments in accordance with FERC's avoided cost rate factors, contained in 18 C.F.R. § 292.304(e). Order No. 07-360 at 13. Additionally, in 2007, the Commission authorized Idaho Power to use the modeling methodology then-approved by the Idaho Public Utilities Commission ("IPUC") for deriving avoided costs that serve as the starting point for negotiations with large QFs. *Id.* PacifiCorp now proposes to use its own unique computer methodology with its GRID model, and Idaho Power seeks confirmation that it may utilize a more recently approved IPUC methodology. PGE appears to seek the right to use a computer model to calculate non-standard rates, or some aspect of the rates, on a case-by-case basis in its discretion. PGE/700, Macfarlane-Morton/9-10; PGE/800, Macfarlane-Morton/6. No party, however, has identified any problems that have arisen with the use of the Commission's current policy.

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### 2. The Commission Should Not Adopt a Computer Modeling Methodology for PacifiCorp and PGE.

The OPUC should reject proposals to adopt a computer modeling methodology for calculating non-standard avoided cost rates for PacifiCorp and PGE. To use a computer model, a QF developer must retain outside technical expertise and may need to purchase expensive licensing rights. *See* CREA/500, Skeahan/17.[5] Without such outside expertise, the model becomes a "black box" to the QF developer. Thus, meaningful use of a model would require the QF developer to incur significant costs very early on in the development process when it is most likely attempting to initially determine basic project feasibility. CREA/500, Skeahan/18. Mandatory use of this type of model will likely become a tool that obstructs QF development by preventing parties from even being able to evaluate basic project viability. *Id*.

While Staff has changed its position on this issue in Phase II and now supports use of a computer model so long as the eligibility for standard rates remains at 10 MW, Staff also agrees with CREA that models introduce transparency problems. Staff/600, Andrus/22. In Phase I of this proceeding, Staff explained that "model-based approaches are not transparent to the QF developers and their lenders[,]" and "the results remain only as accurate as the forecasts and other inputs." Staff/100, Bless/9. These transparency and cost issues are particularly a concern for small QFs, and therefore any change to the 10-MW eligibility cap significantly impacts the resolution of this issue. Staff/600, Andrus/22.

If the Commission determines to permit use of computer models to calculate avoided cost rates, the Commission should adopt rules requiring the utility to cooperate with the developer.

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[5] PacifiCorp asserts that no licensing rights are necessary to access its GRID model, but that does not limit the need for expertise in use of the model.

Without such requirements, the computer modeling approach will provide unfair bargaining power to the utility. Specifically, the Commission should require the utilities to run scenario and sensitivity analyses at the QF's request. CREA/500, Skeahan/18. Staff agrees with these general conditions. Staff/600, Andrus/22. Additionally, as both ODOE and Staff recommend, wholesale market prices should serve as a floor to the avoided cost rates under any modeling methodology. ODOE/900, Carver/10; Staff/700, Andrus/11.

**3. Idaho Power's Single-Run Methodology Should Be Rejected.**

The Commission should not allow use of Idaho Power's "single run" computer methodology.[6] Although the Commission has never authorized Idaho Power's use of the single-run methodology, Idaho Power asks that it "continue to be authorized to utilize this methodology." Idaho Power/1300, Allphin/12. CREA opposes approval of the newly created single-run methodology for Idaho Power or any other Oregon utility. CREA submitted substantial technical evidence in Phase I describing the flaws inherent in Idaho Power's single-run methodology. *See* CREA/200, Reading/4-7.[7]

When the OPUC allowed Idaho Power to utilize the IPUC-approved computer methodology in docket UM 1129, the IPUC-approved methodology was a traditional differential revenue requirement methodology. *See* Idaho Power/200, Stokes/23, 34. The old IPUC methodology was also referred to as a "double-run" methodology because it calculates the utility's revenue requirement once with the QF in the resource stack and a second time without the QF in the resource stack, with the difference being the avoided energy costs. *Id.* While

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6 Idaho Power also refers to this new methodology as the "incremental cost IRP Methodology" or the "ICIRP Methodology." Idaho Power/200, Stokes/33-34.

7 The testimony of Dr. Don C. Reading was admitted into the record in this proceeding on this point and may be relied upon during Phase II.

CREA does not support computer modeling methodologies, the double-run methodology is a well-established method to calculate avoided cost rates. *See Small Power Prod. and Cogeneration Facilities; Regulations Implementing Sec. 210 of the Pub. Util. Reg. Pol. Act of 1978,* Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980) (under this method, "the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal expansion plan, *excluding* the qualifying facility, over the total capacity and energy cost of the system (before payment to qualifying facility) developed in accordance with the utility's optimal expansion plan *including* the qualifying facility"). Despite the transparency limitations inherent in models, the double-run methodology could produce a reasonable approximation of the avoided costs, if conducted properly. *See* CREA/200, Reading/4-7. Now, however, Idaho Power proposes to use the single-run methodology approved by the IPUC in 2012.

Idaho Power insists that the Commission already authorized Idaho Power's use the single-run methodology in Oregon. Idaho Power/1100, Allphin/5-6. Yet Idaho Power identifies no OPUC order finding that the single-run methodology accurately calculates avoided costs. Testimony was presented on the topic in Phase I, but the Commission did not approve Idaho Power's use of the single-run methodology. *See* Order No. 14-058 at 11 ("For negotiated QF contracts, Idaho Power argues that it should use the incremental cost IRP methodology, as it does before the IPUC."); *id.* at 12 ("We defer review of any proposed changes to the calculation of rates for non-standard contracts to the Phase II proceeding."). Although the single-run methodology was not even approved by the IPUC until 2012,[8] Idaho Power appears to suggest that the OPUC approved its use in docket UM 1129. But in Order No. 07-360, the Commission

[8] *See* IPUC Case No. GNR-E-11-03, Order No. 32697 at 21, 2012 Westlaw 6641652 (Dec 18, 2012).

merely approved the "the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro and unplanned outages." Order No. 07-360 at App. A at 1. While not explicitly stated, the only permissible reading of Order No. 07-360 is that the OPUC approved the IPUC's *then-effective* modeling methodology. Otherwise, the order would approve whatever methodology the IPUC might adopt at any point in the future, effectively ceding the OPUC's regulatory authority over Idaho Power's Oregon PURPA purchases to the IPUC. That would be contrary to Oregon law, which requires the OPUC to set avoided cost rates for Oregon QF sales. ORS 758.525(1).

In any event, the issue is now squarely before the Commission, and CREA submits that Idaho Power's new methodology is flawed. The flaw with the single-run methodology is that it pretends that, unlike the output of utility-owned plants, QF output cannot support profitable market sales. The method therefore "ignores the full value QFs contribute." CREA/200, Reading/5. Thus QFs ineligible for standard rates "would not only need to negotiate rates with the utility, but they would also be guaranteed a rate that does not pay the full avoided costs." CREA/200, Reading/7.

Idaho Power has argued that PURPA's avoided cost definition does not provide for the value associated with off-system sales of QF generation. This argument misunderstands the avoided cost rule. FERC directly endorsed the double-run methodology that Idaho Power now argues is inconsistent with FERC's avoided cost rule. *See* Order No. 69, 45 Fed. Reg. at 12,216. A utility cannot calculate the total costs associated with a change in its resource portfolio without considering the impact of the new resource on the utility's off-system sales. *See* CREA/200, Reading/4-7. This is particularly true for Idaho Power because it relies heavily on off-system sales. *See id.* at 5. The single-run methodology will under-compensate any QF subjected to it, and it should not be adopted for any utility in Oregon.

### G. Issue 8: *When is there a legally enforceable obligation?*

The OPUC should amend its administrative rule, OAR 860-029-0010(29), and adopt a policy that allows QFs to obligate themselves to long-term avoided cost rates under a non-contractual legally enforceable obligation. CREA proposes a reasonable policy that is based on FERC's own interconnection and transmission tariffs, which would protect the rights of QFs and utilities in the event of a dispute that may occur during contract negotiations.[9]

#### 1. Legal Background on a QF's Right to a Legally Enforceable Obligation.

FERC's rules provide that each QF shall be provided the option to sell energy and capacity pursuant to a "legally enforceable obligation" (or "LEO") with rates calculated on the date the obligation is incurred. 18 C.F.R. § 292.304(d)(2)(ii); *see also* ORS 758.525(2)(b) (providing that at the option of the QF, prices may be based on "projected avoided costs calculated at the time the legal obligation to purchase the energy or energy and capacity is incurred"). The preamble to FERC's LEO rule explained that this option "enables a qualifying facility to establish a fixed contract price for its energy and capacity at the outset of its obligation . . . ." Order No. 69, 45 Fed. Reg. at 12,224.

FERC has recently provided detailed guidance on the intent and meaning of its LEO rule. FERC has emphasized that "the phrase legally enforceable obligation is broader than simply a contract between an electric utility and a QF and that the phrase is used to prevent an electric

[9] As noted in CREA's Phase II testimony, CREA's position on this issue has not changed from Phase I, where CREA presented testimony on this issue. CREA/500, Skeahan/18.

utility from avoiding its PURPA obligations by refusing to sign a contract, or . . . delaying the signing of a contract, so that a later and lower avoided cost is applicable." *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006, at P 36 (2011). FERC has explained that "a legally enforceable obligation may be incurred before the formal memorialization of a contract to writing." *Grouse Creek Wind Park, LLC*, 142 FERC ¶ 61,187, at P 36 (2013) (internal quotation omitted). Indeed, "a legally enforceable obligation between a QF and a utility may exist regardless of the existence of a contract." *Id.* at P 38. "[I]f the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a noncontractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA." *Id.* at P 40 (internal quotation omitted).

FERC has elaborated further on the purpose of its LEO rule:

> In order to protect the rights of a QF, once a QF makes itself available to sell to a utility, a legally enforceable obligation may exist prior to the formation of a contract. A contract serves to limit and/or define bilaterally the specifics of the relationship between the QF and the utility. A contract may also limit and/or define bilaterally the specifics of the legally enforceable obligation at the heart of that relationship. But the obligation can pre-date the signing of the contract. Moreover, the tool of seeking state regulatory authority assistance to enforce the PURPA-imposed obligation does not mean that seeking such assistance is a necessary condition precedent to the existence of a legally enforceable obligation.

*Id*. (internal quotation and alteration omitted).

While it is up to the states to implement FERC's PURPA regulations, including its LEO rule, a state may not implement PURPA in a manner that is inconsistent with FERC's PURPA regulations. *See* 16 U.S.C. § 824a-3(f). Moreover, FERC's recent declaratory orders interpreting its own LEO rule are entitled to substantial deference. *Decker v. N.W. Envtl. Def.*

*Ctr.*, 133 S. Ct. 1326, 1337 (2013) ("When an agency interprets its own regulation, the Court, as a general rule, defers to it unless that interpretation is plainly erroneous or inconsistent with the regulation." (internal quotation omitted)); *Talk Am., Inc. v. Mich. Bell Tel. Co.,* 131 S.Ct. 2254, 2265 (2011) ("The [Federal Communications Commission] as *amicus curiae* has advanced a reasonable interpretation of its regulations, and we defer to its views."); *Williamson v. Mazda Motor of Am., Inc.,* 131 S.Ct. 1131, 1137 (2011) (relying, in part, on the Solicitor General's amicus brief to interpret a Department of Transportation regulation); *Chase Bank v. McCoy*, 131 S.Ct. 871, 880 (2011) ("Because the interpretation the [Federal Reserve] Board presents in its brief is consistent with the regulatory text, we need look no further in deciding this case.").

### 2. *Exelon Wind I, LLC v. Nelson* Is Inapplicable.

PacifiCorp appears to argue that a recent Fifth Circuit decision undermines FERC's LEO rule. *See Exelon Wind I, LLC v. Nelson*, 766 F.3d 380 (5th Cir. 2014). In *Exelon Wind I, LLC*, the Fifth Circuit affirmed the Texas commission's rule that a QF may only obtain a non-contractual LEO if that QF is able to make "firm" power deliveries. *Id.* at 396. The court did so even though FERC had determined that Texas's firm power requirement was inconsistent with FERC's LEO rule. *See id.* at 387 n.5 (citing *J.D. Wind 1, LLC,* 129 FERC ¶ 61,148 (Nov. 19, 2009)). According to PacifiCorp, the *Exelon Wind I, LLC* decision provides the OPUC with wide discretion in implementing FERC's LEO rule. *See* PAC/1000, Griswold/14-15. But the *Exelon Wind I, LLC* decision has no applicability here for multiple reasons.

First, although the *Exelon Wind I, LLC* majority opinion essentially ignored a FERC declaratory ruling interpreting FERC's own LEO rule, the decision has no applicability here because Oregon is not located in the Fifth Circuit. We are located in the Ninth Circuit, where the federal courts accord great deference to a federal agency's interpretation of its own regulations. *See, e.g.*, *Public Lands for the People, Inc. v. U.S. Dept. of Agric.*, 697 F.3d 1192, 1199 (9th Cir.2012) (according "wide deference" to the Forest Service Manual's interpretation of a regulation); *Barboza v. Cal. Ass'n of Prof'l Firefighters*, 651 F.3d 1073, 1076, 1079 (9th Cir. 2011) (deferring to the interpretation of a regulation advanced in an *amicus* brief by the Department of Labor); *Siskiyou Reg'l Educ. Project v. U.S. Forest Serv.*, 565 F.3d 545, 548, 554–57 (9th Cir. 2009) (deferring to the interpretation of a "mining-related directive" set forth in a "Memorandum to Regional Foresters" issued by the Forest Service); *Silvas v. E*Trade Mortg. Corp.*, 514 F.3d 1001, 1005 n. 1 (9th Cir. 2008) (deferring to an Office of Thrift Supervision legal opinion interpreting a regulation); *L.A. Closeout, Inc. v. Dep't of Homeland Sec.*, 513 F.3d 940, 941–42 (9th Cir.2008) (deferring to an internal memorandum used by the Department of Homeland Security in interpreting a regulation).

Second, the *Exelon Wind I, LLC* majority opinion ignored FERC's interpretation of its regulation (which it referred to as "FERC's letter") only after concluding that the QFs' attorney "conceded at oral argument that FERC's Letter is not entitled to deference." *Exelon Wind 1, LLC*, 766 F.3d at 397.[10] No such concession exists in this case.

In any event, even if *Exelon Wind 1, LLC* created a heightened level of deference to a state's interpretation of FERC's LEO rule, Oregon's courts have already interpreted FERC's LEO rule consistent with FERC's recent interpretations. *See Snow Mt. Pine Co. v. Maudlin*, 84

[10] Indeed, deference to an agency's interpretation of its own regulation is so strong that the concurring and dissenting opinion in *Exelon Wind I, LLC* would have deferred to FERC's interpretation even in spite of this concession by counsel. *Exelon Wind 1, LLC*, 766 F.3d at 404-13 (Prado, J., concurring and dissenting) (explaining, "if 18 C.F.R. § 292.304(d) really were ambiguous, FERC's interpretation of that regulation in its 2009 Declaratory Order would ordinarily control our court's interpretation 'unless it is plainly erroneous or inconsistent with the regulation.'"). This concurring and dissenting opinion also persuasively points out a number of other flaws in the majority opinion.

Or. App. 590, 598-600, 734 P.2d 1366 (1987). Indeed, over two decades prior to the recent declaratory rulings by FERC, the Oregon Court of Appeals provided the same interpretation of FERC's LEO rule as FERC itself recently provided. In *Snow Mt. Pine Co.*, the utility insisted that the LEO could be created "*only* when the utility and a qualifying facility execute a written contract for the purchase of power or when the commissioner issues an order determining the contract terms for the parties in a case brought before him . . . ." 84 Or. App. at 598 (emphasis added). The Commission's order apparently endorsed this view, and determined that rates would be calculated as of the date of the Commission's final order instead of the earlier date on which the QF tendered an agreement. *Id.*

The Oregon Court of Appeals rejected the arguments of the utility and the Commission. The court explained: "the obligation to purchase power is imposed by law on a utility; it is not voluntarily assumed." 84 Or. App. at 599. "To permit a utility to delay the date to be used to calculate the purchase price simply by refusing to purchase energy would expose qualifying facilities to risks that we believe Congress and the Oregon Legislature intended to prevent." *Id*. The court further relied upon FERC's preamble to its LEO rule, where FERC "suggests that a utility cannot merely by refusing to enter into a contract, deprive a qualifying facility of its right to commit to sell power in the future at prices which are determined at the time the qualifying facility makes its decision to provide power." *Id.* at 600 (internal quotation omitted). The court held that the QF obligates the utility "by tendering an agreement that obligates it to provide power" – thus rejecting the view that the QF must wait for a final Commission order to create a LEO. *Id.*

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### 3. The OPUC Should Amend OAR 860-029-0010(29) and Clarify Its LEO Policy.

In contradiction to FERC's orders and the *Snow Mountain Pine* decision, the OPUC's existing administrative rule requires the utility's written agreement to create a LEO. *See* OAR 860-029-0010(29) (defining "time the obligation is incurred" as the earlier of the date on which a binding written obligation is entered into, or the "the date agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate"); *see also* OAR 860-029-0040(3) (providing the QF the option to elect to have avoided costs calculated "at the time the obligation is incurred"). Because the current OPUC rule requires a written agreement from the utility, it unlawfully implements both FERC's LEO rule and the *Snow Mountain Pine* decision. The OPUC must amend this administrative rule, and no party appears to argue otherwise.

The OPUC should replace OAR 860-029-0010(29) with a policy that allows QFs to create a LEO after attempting to negotiate and reaching an impasse with a utility. CREA recommends adoption of a policy whereby QFs create a LEO by negotiating to a point of disagreement and then requesting that a utility file a disputed contract unexecuted with the OPUC for resolution. *See* CREA/100, Hilderbrand/18-19. The QF may not simply sign a form contract at the first point of contact under CREA's proposal; instead, the QF must attempt to proceed through the Commission-approved contracting process to the point where the utility refuses to provide a contract acceptable to the QF, or otherwise fails to timely process the contract request in accordance with the tariff. *See id.* This is the FERC policy for interconnection agreements that appropriately recognizes the parties may reach an impasse, and allows for preservation of the queue position by filing the utility's proposed agreement unexecuted for resolution of disputed issues. *Standardization of Generator Interconnection Agreements and Proc.*, Order No. 2003,104 FERC ¶ 61,103, P 240 (2003). By requesting that the disputed PURPA contract be filed unexecuted, the QF would formally agree to be bound by the terms ultimately deemed reasonable by the OPUC, and thereby create a LEO.

The utilities propose a process where a LEO could not be formed until the QF agrees to all of the utility's final terms and conditions. PAC/1000, Griswold/19-20. This requirement fails for the same reason that a fully executed contract requirement fails – it requires the QF to agree to all terms and conditions imposed by the utility. It also ignores that disputes can arise outside of the terms of the contract. For example, utilities sometimes dispute the QF's entitlement to the contract in the first place, which precludes the QF from obtaining a final draft contract from the utility. *See, e.g.*, *Surprise Valley Electrification Corp. v. PacifiCorp*, OPUC Docket No. UM 1742 (dispute over entitlement to sell power to PacifiCorp and related LEO issue). In contrast to the utility proposals, an unexecuted filing requirement is universally adaptable to all situations and properly allows the QF to create a LEO by binding itself to the terms to be set by the OPUC.

### H. Issue 9: ***How should third-party transmission costs to move QF output in a load pocket to load be calculated and accounted for in the standard contract?***

The Commission should adopt CREA's reasonable proposal to provide QFs with alternative options to account for third-party transmission costs, including a fixed-price option. CREA's proposal complies with PURPA while still providing flexibility in accounting for these costs.

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### 1. The Phase II Load Pocket Issue.

In Phase I, the Commission determined that any third-party transmission costs incurred by a utility to move QF output from the point of delivery to load should be the responsibility of the QF under the avoided cost principles. Order No. 14-058 at 22. However, the Commission deferred to Phase II the question of how to calculate and assign the third-party transmission costs that are attributable to the QF. *Id.* The Commission directed the parties to recommend how third-party transmission costs to transport QF output from receipt in a load pocket to load should be accounted for in standard contracts – "for example, by lowering standard avoided cost rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means." *Id*. at 23.

### 2. PURPA's Requirements Govern the OPUC's Resolution.

PURPA provides three guiding principles that the Commission must follow in resolving this issue.

First, PURPA entitles the QF to compel the purchasing utility to accept and purchase the QF's entire net output made available to the purchasing utility. 16 U.S.C. § 824a-3(a)(2); 18 C.F.R. § 292.303(a). FERC has stated: (1) the QF's obligation to the purchasing utility is limited to delivering energy to the point of interconnection by the QF with that purchasing utility; (2) the QF is not required to obtain transmission service, either for itself or on behalf of the purchasing utility, in order to deliver its energy from the point of interconnection with the purchasing utility to the purchasing utility's load; and (3) the purchasing utility cannot curtail the QF's energy as if the QF were taking non-firm transmission service on the purchasing utility's system. *Pioneer Wind Park I, LLC,* 145 FERC ¶ 61,215, P 38 (2013). In *Pioneer Wind Park I, LLC*, however, FERC explained that PURPA allows for an adjustment to the avoided cost rates to account for transmission limitations on the purchasing utility's side of the QF delivery. *Id.* at P 41 n.79 (stating, "parties could, for example, agree to prices that reflect the new transmission project entering service, and also to alternative prices should the new transmission project not enter service").

Second, PURPA entitles the QF to compel the purchasing utility to pay fixed avoided cost rates calculated at the time the QF incurs the obligation to deliver energy and capacity. *See* 18 C.F.R. § 292.304(b)(5), (d)(2)(ii). The purpose of fixed rates is to provide the QF with "certainty with regard to return on investment." Order No. 69, 45 Fed. Reg. at 12,224. Thus, any adjustment to the avoided cost rates to account for the purchasing utility's transmission costs must still provide the QF with the option to sell at fixed avoided cost rates – not a rate that will vary through time.

Third, a QF may agree to terms and conditions that differ from those to which it is otherwise entitled to compel through the mandatory purchase obligation. 18 C.F.R. § 292.301(b). FERC has explained: "Section 292.301(b)(1) permits a QF and an electric utility to enter into a contract containing agreed-to rates, terms, or conditions that may differ from those that would otherwise be required by [FERC's] regulations concerning the determination of avoided-cost rates." *Cedar Creek Wind LLC*, 137 FERC ¶ 61,006, at P 39 n.73. Thus, although a state must provide QFs with contracting options that comply with the minimum requirements of FERC's PURPA regulations, a state commission may also provide additional options that the QF may elect to choose instead. *See Winding Creek Solar LLC*, 151 FERC ¶ 61,103, P 6 (2015) ("as long as a state provides QFs the opportunity to enter into long-term legally enforceable obligations at avoided cost rates, a state may also have alternative programs that QFs and electric utilities may agree to participate in . . . ."); *Otter Creek Solar, LLC*, 143 FERC ¶ 61,282, at P 4 (2013), *reconsid. denied*, 146 FERC ¶ 61,192 (2014) ("Nothing in [FERC's] regulations limits the authority of either an electric utility or a QF to agree to rates for any purchases or terms or conditions relating to any purchases which differ from the rates or terms or conditions which would otherwise be required by the [FERC's] regulations.").

**3. The Commission Should Adopt CREA's Proposed Alternatives.**

Given the limitations imposed by PURPA, the Commission must offer one backstop option that provides the QF with a fixed-price avoided cost rate, and CREA recommends that the Commission should also provide two additional options that could result in a more reasonable outcome for all parties. These three options include:

(1) A reasonable long-term fixed price option;

(2) An alternative option whereby the QF voluntarily waives its right to fixed prices and enters into a new standard contract addendum that will account for the purchasing utility's actual costs of third-party transmission; and

(3) Another alternative option whereby the QF voluntarily waives its rights to deliver and sell all of its output and enters into a new standard contract addendum that provides PacifiCorp with a narrowly tailored curtailment right to address the load pocket problem.

CREA/500, Skeahan/26.

**a. PURPA Requires a Fixed-Price Option.**

The first option – a fixed reduction to the fixed prices otherwise available in the standard contract – must be offered to all "load pocket" QFs in order to meet PURPA's requirement that QFs be entitled to sell all of their output at a fixed avoided cost rate. 18 C.F.R § 292.304(b)(5), (d)(2); ORS 758.525(2)(b) Aside from PURPA's legal requirements, this option is important because many QFs will require the certainty of a fixed price in order to obtain construction financing. CREA/500, Skeahan/24. PacifiCorp has exhibited the ability to offer this option because it entered into a contract with TMF Biofuels with a fixed-price reduction to the standard avoided costs, which was based on a reasonably escalated cost for Bonneville Power Administration ("BPA") transmission. CREA/502, Skeahan/4; CREA/700, Skeahan/4; PAC/1300, Griswold/16.

PacifiCorp ignores PURPA's requirements and proposes that QFs be responsible for the unfixed transmission costs that PacifiCorp incurs in delivering QF output to load. Third-party transmission costs are not fixed. PAC/1300, Griswold/16. Instead, transmission providers often implement significant transmission rate increases. *See* 77 Fed. Reg. 66,966 (Nov. 8, 2012) (announcing BPA's transmission rate case). PacifiCorp would assign these unfixed transmission cost to QFs. PAC/1300, Griswold/15-16. This violates QFs' rights to fixed rates. PacifiCorp incorrectly analogizes to the situation where an off-system QF is subject to unknown transmission costs to deliver its output to the purchasing utility's system. PAC/1300, Griswold/19-20. An *indirectly* connected QF (or "off-system" QF) must incur such costs under FERC's regulations in order to deliver its output to the purchasing utility's system. 18 C.F.R. § 292.303(d). But PacifiCorp may not compel the QF to do more than deliver its output to the point of interconnection with PacifiCorp. *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61215, at P 38. Once the QF delivers its output to the purchasing utility's system, PURPA entitles the QF to sell its output at a fixed-price avoided cost rate. 18 C.F.R. § 292.304(d)(2)(ii).[11]

[11] Furthermore, while PacifiCorp complains that the load pocket costs could increase above what is estimated in a fixed-price PURPA contract, PacifiCorp's argument overlooks that the circumstances could (*continued onto next page*)

**b. The Commission Should Also Provide Alternatives to a Fixed-Price Rate that May Prove More Economically Efficient.**

As noted above, PURPA allows QFs to agree to alternatives other than the fixed-price rate the QF could compel through PURPA's purchase obligation. In most instances, simply paying for the limited amount of transmission needed (CREA's second option) or agreeing to limited curtailment of output (CREA's third option) will be the most economically efficient option for the QF. *See* CREA/500, Skeahan/23-24. The record demonstrates that, in many instances, the load pocket problem will present itself in only very limited circumstances. *Id.* Furthermore, the record demonstrates that PacifiCorp has the legal right to re-direct the points of receipt and delivery in its existing transmission rights to deliver QF output to load. *Id.* PacifiCorp has in fact re-directed under-utilized third-party transmission to deliver the output of the Three Mile Canyon Wind QF. CREA/502, Skeahan/1-2. Thus, the Company already possesses excess third-party transmission to address the problem at least some of the time. Additionally, PacifiCorp itself acknowledges that a large new load that comes online after the QF could completely eliminate the load pocket problem for the remainder of that QF's PURPA contract. *See* PAC/1300, Griswold/14.

Thus, it is reasonable for the Commission to allow a QF to agree to a limited waiver of its PURPA rights in order to more accurately account for the actual economic circumstances. Assessing actual transmission costs to the QF (CREA's second option) or implementing a

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also change to PacifiCorp's benefit. If a new large load arrives in the QF's load pocket, the long-term fixed-price rates could eventually prove to be *lower* than the actual avoided costs. PAC/1300, Griswold/14. In addition to providing the QF with price certainty, a fixed-price rate also serves to secure the benefit of the bargain for the purchasing utility and its customers. *See* Order No. 69, 45 Fed. Reg. at 12,224 ("should the actual avoided costs be higher than those contracted for, the electric utility is nevertheless entitled to retain the benefit of its contracted for, or otherwise legally enforceable, lower price for purchases from the qualifying facility").

limited curtailment of QF output (CREA's third option) would require a new standard contract addendum to ensure that the accounting or curtailment is reasonable. CREA/500, Skeahan/25; CREA/700, Skeahan/4-5. Staff agrees that CREA's proposed alternatives are reasonable and recommends that the Commission direct PacifiCorp to implement these proposals. Staff/600, Andrus/29-30. PacifiCorp's objections, however, are unreasonable.

CREA's second proposed option for QFs is essentially a more complete description of PacifiCorp's own proposal that QFs be assigned the actual costs associated with delivering their output to load. Yet PacifiCorp objects to CREA's position on the ground PacifiCorp should not be bound by reasonable contract terms defining its rights to assign actual (instead of forecasted) transmission costs to the QF. PAC/1300, Griswold/18 (criticizing CREA's proposal for contract terms delineating the parties' rights because it "could lead to disputes on decisions and possible litigation"). Although PacifiCorp objects to being legally bound by any reasonable limitations on its rights, PURPA entitles the QF to a legally enforceable obligation or other contractual arrangement to sell its output to PacifiCorp. 18 C.F.R. 292.304(d). If PacifiCorp is not willing to be legally bound to act reasonably in assigning to QFs the costs of load pocket transmission, then PacifiCorp should not be allowed to assign these costs to QFs or to its retail customers. CREA/700, Skeahan/5.

Finally, PacifiCorp is incorrect to assert that CREA's third proposed option violates PURPA's prohibition against curtailing QF output. *See* PAC/1300, Griswold/18; PAC/1600, Griswold/7. CREA agrees that PacifiCorp may not unilaterally impose a curtailment term in a PURPA contract, or provide that as the only option to the QF. As explained above, however, so long as the Commission provides an option that meets PURPA's requirements, QFs are entitled to agree to terms and conditions that differ from PURPA's requirements. 18 C.F.R. § 292.301(b); *Otter Creek Solar*, *LLC*, 143 FERC ¶ 61,282, at P 4. Under CREA's proposal, the QF will only be subjected to curtailment on account of load pocket limitations if the QF elects not to exercise its right to the fixed-price reduction to the standard rates available under CREA's first option. CREA/700, Skeahan/5. CREA's proposal would be a lawful and reasonable implementation of PURPA.

## IV. CONCLUSION

CREA respectfully requests that the OPUC adopt the policies recommended herein.

RESPECTFULLY SUBMITTED this 2nd day of September 2015.

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