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June 12, 2018

Via Electronic Mail

Mr. Mark L. Johnson
Executive Director and Secretary
Washington Utilities and Transportation Commission
1300 South Evergreen Park Drive S.W.
P. O. Box 47250
Olympia, WA 98504-7250

Attn: Filing Center

RE: In the Matter of Public Utilities Regulatory Policies Act, Obligations of the Utility to Qualifying Facilities, WAC 480-107-105
Docket No. U-161024

Dear Mr. Johnson:

Please find attached Excerpts on QF Financing from the Northwest and Intermountain Power Producers Coalition and the Renewable Energy Coalition, which were requested at the May 14, 2018 workshop in the above-referenced docket.

Thank you for your assistance. Please do not hesitate to contact me with any questions.

Sincerely,

Irion Sanger

Irion A. Sanger

Testimony on QF Financing

North Carolina Utilities Commission Excerpts

1. Docket No. E-100 Sub 148, Direct Testimony of Patrick McConnell at 5-7 (Mar. 28, 2017) (describing how important the credit quality and tenor of a [power purchase agreement ("PPA")] is in the capital raising process and concluding that "[l]imiting contacts to 10 years … would make it significantly more difficult if not impossible to attract the required level of equity investment").

2. *See also id.* at 4 (noting that most solar developers require "a combination of sponsor equity (internal capital), construction loans, permanent loans, and tax equity to finance the construction and operation" of projects).

Michigan Public Service Commission Excerpts

1. Case No. U-18090, Direct Testimony of Adam Schumaker at 4 (Oct. 27, 2016) (explaining why the "PPA is the centerpiece of project financing").

2. *Id.* at Exhibit A-7 (demonstrating the impact of PPA terms and resulting shorter amortization periods on project financing).

Public Service Commission of Utah Excerpts

1. Docket No. 15-035-53, Final Order at 19-20 (Jan. 7, 2016) (lamenting that "[n]o party presented information in this docket attempting to quantify the impact a change in contract term would have on financing terms, and by extension, on the viability of future [qualifying facility ("QF")] projects" while nevertheless finding evidence in the record to support a 15-year contract term).

Public Service Commission of Wyoming Excerpts

1. Docket No. 20000-481-EA-15, Final Order at 11-12 (June 23, 2016) (addressing potential effects of a three-year PPA term and primary reasons that commercial banker QF investors will not finance short-term PPAs).

2. *Id.* at 21 (declining to make any changes to its PURPA policy requested by PacifiCorp, dba Rocky Mountain Power ("RMP") and noting "[a]dopting RMP's proposal also risks discouraging QF development in Wyoming in contravention of [the Public Utility Regulatory Policies Act ("PURPA")] and maintaining 20-year contract term).

Public Service Commission of Montana Excerpts

1. Docket No. D2014.4.43, Testimony of Greenfield Wind, LLC at MHW-4- 9 (July 28, 2014) (describing the development of the Greenfield Project, including financing and other issues specific to community renewable energy projects).

Oregon Public Utility Commission Excerpts

1. Docket No. UM 1610, Direct Testimony of Ormand Hilderbrand at CREA/100, Hilderbrand/4 (Mar. 18, 2013) (explaining challenges unique to developing smaller scale QF projects and noting "trying to finance a $20 million community renewable project is almost impossible" because "financing institutions much prefer larger loan amounts where the risk can be syndicated amongst several institutions").

2. *Id.* at 9-20 (describing financing problems specific to the PaTu project and concluding "[t]he current term of 15 years with fixed rate is the absolute minimum that can be financed by a 10 MW project … I cannot see a possibility of obtaining financing for major turbine upgrades with only a 5-year fixed-rate tariff").

3. Docket No. UM 1129, Order No. 05-584 at 19-20 (May 13, 2005) (relying upon Oregon Department of Energy ("ODOE") testimony that 20 years is the minimum term needed to establish financing, given ODOE's role as a QF facilitator and financier).

4. Docket No. UM 1129, ODOE Rebuttal Testimony of Jeff Keto at ODOE/Exhibit No. 9, Keto/2 (Jan. 20, 2006) (explaining ODOE's role as a QF financier and its experience that most projects need a PPA with limited risk to finance their project).

5. Docket No. UM 1129, ODOE Testimony of Jeff Keto at ODOE/Exhibit No. 3, Keto/1-2 (Aug. 3, 2004) ("The loan program has financed 16 projects for between 20 and 25 years, three for shorter terms and two for up to 30 years … While developers might prefer longer terms, 20 years should allow for adequate financing of the majority of QF projects our program has reviewed … For many projects, terms less than 20 years will make it difficult to cover loan payments from the power sales revenue.").

6. *Id.* at 3 ("I believe a 20-year maximum contract length is necessary for successful financing for many projects. The proposed 20 years is 10 to 20 years shorter than utility ownership of natural gas and coal fired power plants, respectively, which lock utility customers in for 30 to 40 years, respectively. In addition, information obtained from the Commission's Staff Settlement Proposal showed several examples of utilities' plans or RFPs that call for contracts up to 20 years. If

utilities are allowed to expose the ratepayers to long-term commitments with fossil fuel power plants or RFP contracts, the same should be true with QF contracts.”).

7. *Id.* (“For a project to make timely loan payments, adequate power sales revenue must be received each year. A QF facility should have the choice of levelized capacity payments if early year payments are significantly lower. This would ensure adequate revenues if there are years with low capacity payments.”).

8. Docket No. UM 1129, ODOE Direct Testimony of Jeff Keto at ODOE/Exbibit No. 6/, Keto/9 (Dec. 9, 2005) (“Termination for late start up or under-delivery of power will make many QF project unfinanceable”).

9. Docket No. UM 1129, ODOE Surrebutal Testimony of Jeff Keto at ODOE/Exhibit No. 4, Keto/1 (Oct. 14, 2004) (addressing “significant disadvantage” if QFs are not able to contract in the 20 to 30 year range available in wholesale market).

10. Docket No. UM 1734, Response Testimony of John Lowe at Coalition/100, Lowe/6 (Oct. 15, 2015) (“In my experience, not all of the QFs that request contracts, or that even those that enter into contracts, ever come on line … [due to] project financing, ordinary risks of development, resource or project location and interconnection costs, utility process and interests, and many other factors that ultimately reduce the number of proposed projects that are eventually constructed.”).

11. *Id*. at Coalition/100, Lowe/11-12 (“Existing projects have financing and planning needs very similar to those of proposed projects … [because] the expiration of a power purchase agreement is often the appropriate time to revise and update a project … [and] could include additions and improvements as well as updating of equipment to then-current standards [that are] often significant in terms of financial, process and timing considerations that must align with the contracting process and contract terms, including contract length and prices of a power purchase contract renewal.”).

12. Docket No. UM 1734, Response Testimony of Jeremiah Camarata and Edson Pugh at Coalition/200, Camarata-Pugh/8-10 (Oct. 15, 2015) (supporting 20-year contract terms with 15 years of fixed prices as adequate to facilitate “financing needed to make system improvements, repairs, and meet or exceed environmental requirements” and discussing need for long-term financing to make capital improvements).

13. Docket No. UM 1725, Response Testimony of John Lowe at Coalition/100, Lowe/9-10 (July 31, 2015) (illustrating how “short contract terms means that there will always be a period of resource sufficiency, which may prevent QFs from being paid for capacity”).

Federal Energy Regulatory Commission Excerpts

1. *Windham Solar LLC*, 157 FERC ¶ 61,134 at P.8 (2016) ("the Commission … has explicitly agreed with previous commenters that stressed the need for certainty with regard to return on investment in new technologies. Given this need for certainty with regard to return on investment, coupled with Congress' directive that the Commission encourage QFs, a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors.") (quotation and citations omitted).

2. *JD Wind 1, LLC*, 130 FERC ¶ 61,127 at P.23 (2010) ("The Commission has, since [issuing Order No. 69], consistently affirmed the right of QFs to long-term avoided cost contracts").

3. *Order No. 69*, FERC Stats & Regs ¶ 30,129 at 30,880 (Feb. 25, 1980) ("in order to be able to evaluate the financial feasibility of a [QF] facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility. This return will be determined in part by the price at which the qualifying facility can sell its electric output."), *available at* https://www.ferc.gov/industries/electric/gen-info/qual-fac/orders.asp.

4. *Id.* at 30,881 (declining to protect the "financing ability" of generation and transmission cooperatives by noting that if FERC allowed requirements contracts to override the mandatory purchase obligation, it "might be used to hinder the development of cogeneration and small power production.").

5. *See also* FERC Docket No. AD16-16-000, Technical Conference on Implementation Issues Under PURPA (June 29, 2016) (addressing financeable contract term), *available at* https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8242&CalType=%20&CalendarID=116&Date=&View=Listview.

North Carolina Utilities Commission

Docket No. E-100 Sub 148, Direct Testimony of Patrick McConnell

Mar. 28, 2017

KEYES&FOX LLP

March 28, 2017

Via Electronic Filing

Ms. Martha Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street
Raleigh, North Carolina 27603-5918

RE: In the Matter of the Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2016
Docket No. E-100 Sub 148

Dear Ms. Jarvis,

Please find enclosed for filing in the above-referenced docket the *Direct Testimony of Patrick McConnell* on behalf of Cypress Creek Renewables. Please do not hesitate to contact me if you have any questions.

Thank you for your assistance with this matter.

With best regards,

/s/ Thadeus B. Culley

Thadeus B. Culley
KEYES & FOX, LLP
401 Harrison Oaks Boulevard, Suite 100
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Attorney for Cypress Creek Renewables

Enclosure

cc: Service List for Docket No. E-100 Sub 148

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:

Biennial Determination of Avoided Cost
Rates for Electric Utility Purchases from
Qualifying Facilities – 2016

DIRECT TESTIMONY

OF

PATRICK MCCONNELL

ON BEHALF OF
CYPRESS CREEK RENEWABLES

Q. Please state your name, occupation, and employer.

A. My name is Patrick McConnell. I am a Managing Director and part owner of Cypress Creek Renewables ("CCR"), a utility scale solar developer with a primary focus on the development, construction, and operation of qualifying facilities ("QFs") nationwide. My primary role at CCR is managing the project finance team.

Q. On whose behalf are you providing this testimony?

A. I am providing this testimony on behalf of Cypress Creek Renewables.

Q. What is the purpose of your testimony?

A. I have been asked to provide testimony regarding the impact of some of the changes proposed by Duke Energy Progress, Duke Energy Carolinas (collectively, "Duke"), and Virginia Electric Power Company (collectively, "the Utilities") in their avoided cost filings on Cypress Creek's project development, and more broadly on the development of QFs in North Carolina. Specifically, I discuss the following proposals made by the Utilities: (1) the proposal to eliminate the 5- and 15-year options for standard offer fixed contracts in favor of a single 10-year option; (2) the proposal to readjust energy prices under standard offer contracts every two years; and (3) the proposal to reduce the standard offer threshold to 1 MW.

Q. Have you testified before this Commission or any other utilities commission?

A. I have not previously testified before this Commission. I have testified before another utilities commission on one occasion. In late 2016 and early 2017, I testified before the Montana Public Service Commission, on behalf of Cypress

Creek Renewables and FLS Energy, in the currently-pending avoided cost proceeding for NorthWestern Energy (Docket No. D2016.5.30). My testimony addressed two issues on which the Montana Commission had requested additional testimony from the parties: standard-offer contract length and performance measures with respect to QF contracts.

Q. Please describe your experience in project finance and more specifically solar finance.

A. After graduating from the University of Virginia with a B.A. in Economics and a Concentration in Finance, I began my professional career in the Structured Finance Group of Legg Mason Capital Markets. As the lead analyst of the Structured Finance group, I focused on the modeling, underwriting, and financing of long-term credit tenant leases and corporate asset monetization programs. Our group, as part of Legg Mason and then later RBS Greenwich Capital, originated and structured over $2 billion worth of securities backed by long-term, investment grade leases, very similar to the credit profiles found in long-term utility power purchase agreements.

After obtaining my MBA at the University of North Carolina but prior to joining Cypress Creek, I spent four years within the structured finance team of Stonehenge Capital Company, a boutique investment bank focused on tax incentivized investments for institutional and corporate clients. These investments ranged from film productions, brownfield remediations, historic rehabilitations, low-income housing developments, and of the most relevance, renewable energy installations.

After participating in the financing of over $300 million of renewable project financings at Stonehenge, including landfill gas-to-energy, solar thermal, and solar PV projects, I co-founded Heelstone Energy, LLC, a privately owned solar developer and independent power producer. Heelstone now operates a solar PV portfolio in excess of 200 MW.

Q. Please elaborate on your day-to-day role at Cypress Creek.

A. At CCR, my primary responsibilities include sourcing construction and permanent capital for all of our solar project portfolios, then leading the transaction executions with our capital partners. Outside of outright project sales and sale leaseback transactions, every financing transaction we close involves permanent debt and tax equity investors. Typical investors of both debt and tax equity include large banks, insurance companies, and public corporations.

Q. What are the sources of funding that Cypress Creek generally uses to finance the construction and operation of its solar projects in North Carolina?

A. Like most other solar developers, Cypress Creek uses a combination of sponsor equity (internal capital), construction loans, permanent loans, and tax equity to finance the construction and operation of all of its projects in North Carolina. "Tax equity" refers to equity investments where the investor's primary return can be attributed to its right and ability to utilize investment tax credits and other tax benefits generated by the project. The biggest players in the tax equity market are large banks, corporations, and other institutional investors. Each piece of the external capital stack (construction debt, permanent debt, and tax equity) is sourced from different partners on a deal by deal basis, but to date CCR has used over 25 different capital providers in those roles.

Q. In the capital raising process, can you speak to the importance of the credit quality and tenor of the PPA?

A. Those two pieces of information, along with the actual pricing of the power purchase agreement ("PPA"), are the most critical components of the entire financing. Similar to financings I was involved with in the real estate world, where investors were focused on the credit quality of the tenants above all other things (as opposed to the underlying value of the real estate), investors in renewable energy are primarily focused on the strength of the off-taker and the details of the off-take contract signed. Technological risk has become less of a concern as the industry has matured, but the utility's balance sheet (or FICO scores in the residential world) is of the utmost importance.

Similarly, the term of the contract is equally significant. Without reasonable certainty as to contracted cash flows based on a defined term at a defined price, the institutional marketplace is generally unwilling to take pricing risk. Said a different way, project lenders are unwilling to bet on a utility's avoided cost in QF markets, unless set forth in a fixed contract. In the absence of some sort of third-party credit enhancement (like a government guaranty), I've yet to see a loan maturity or amortization for a project under 75 MW extend beyond the term of a fixed-price PPA. This means that substantially more sponsor equity would be required to generate sufficient funding for the construction and operation of the project. As a result, the cash flow profiles of investments with PPAs of less than at least 15 years, and in most cases 20 years, simply do not make economic sense for smaller projects.

Q. How would the utilities' proposal to limit the length of standard-offer contracts to 10 years impact the development of QFs in North Carolina?

A. As mentioned in the previous answer, for smaller projects (and even for the majority of larger projects), lenders are generally unwilling to lend against uncontracted cash flows. This is especially true for smaller transactions projects (below about 50 MW), that are not of sufficient scale to attract larger, more sophisticated investors who may be willing to accept a few years of merchant or avoided cost exposure if certain underwriting protections are in place. Many in the industry actually consider the original standard offer contract length of 15 years to be insufficiently long compared to average utility contract tenors of 20 or 25 years. 10-year PPA tenors will lead to 10-year amortization periods, which will mean less debt and greater sponsor equity requirements at lower returns and greater risk. This in turn will result in many fewer projects getting financed and constructed.

Q. How would the proposal to limit standard-offer contracts to 10 years impact equity financing for QF projects?

A. Limiting contracts to 10 years would have a two-fold impact. First, by reducing the amount of debt available to finance the project, it would increase the amount of equity required and thereby reduce the rate of return on that equity investment. Second, due to a larger percentage of the project's cash flows being uncontracted and inherently riskier, the projected rate of return required to attract equity investments would be significantly higher. These two dynamics in conjunction would make it significantly more difficult if not impossible to attract the required level of equity investment.

Q. Can you also speak to the importance of having fixed energy prices under a long-term PPA?

A. I view energy prices as one in the same with contract tenor for QFs subject to PURPA in regulated markets. Technically speaking, any QF is entitled to the avoided cost rate at any time per PURPA. What creates value in the contract is having a set avoided cost rate for a set period of time. Without set rates, lenders are unwilling to bet on what the avoided cost rates will be going forward. Fixed rates for a fixed period of time create financeable contracts.

Q. How would Duke's proposal to readjust energy prices under standard offer contracts every two years impact the development of QFs in North Carolina?

A. As I mentioned earlier, QF status entitles a project to sell to the utility at an avoided cost rate even without a PPA, so in a regulated market a ten-year contract with a two-year reset for energy prices would be viewed as more or less equivalent to a two-year contract. Having fixed capacity pricing for the duration of the contract would not make a significant difference, especially given the relatively low price of capacity under the proposed rate schedules. Financing parties would view a ten-year contract with a two year readjustment no more favorably than they would a two-year contract, which (as I have said previously) would not be financeable in the current environment.

Q. How would the Utilities' proposal to reduce the standard-offer threshold to 1 MW impact the development of QFs in North Carolina?

A. Given the complicated nature of these financings, scale is critical in project financing. Reducing the standard offer contract threshold to 1 MW would make financing projects in North Carolina much more challenging. The only way to make most financings work with a 5 MW threshold was to group them into portfolios to create critical mass for debt and tax equity investors. With a 1 MW limitation, the portfolio size would quickly become unwieldy due to the amount of diligence required for that number of projects. It would largely shut out the institutional market from financing standard offer contracts.

Q. Given CCR's focus on QF Markets, can you explain why investors cannot simply rely on the regulatory framework in place in these markets to ensure projects will have viable offtake agreements beyond the PPA terms?

A. While QF markets are certainly a key piece of the CCR strategy of investing in long-lived assets that will have considerable value long after the initial PPA has expired, institutional lenders are generally unwilling to take pricing risk beyond the PPA term. So while the QF designation affords CCR greater economies of scale for our development efforts and improves the long-term viability of each project we develop, it does not typically provide for enhanced upfront financing.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I certify that on this date a copy of the **Direct Testimony of Patrick McConnell** on behalf of Cypress Creek Renewables has been served to all parties of record in Docket No. E-100, Sub 148 by electronic mail or U.S. mail, postage prepaid and properly addressed.

This the 28th day of March, 2017.

*/s/ Blake Elder*___

Blake Elder
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Michigan Public Service Commission

Case No. U-18090, Direct Testimony of Adam Schumaker and Exhibit

Oct. 27, 2016

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, establishing the method and avoided cost calculation for **CONSUMERS ENERGY COMPANY** to fully comply with the Public Utilities Regulatory Policy Act of 1978, 16 USC 2601 *et seq.*	))))))	Case No. U-18090

DIRECT TESTIMONY OF

ADAM SCHUMAKER

ON BEHALF OF

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, AND VOTE SOLAR

October 27, 2016

Q. What is your name, address, and occupation?

A. My name is Adam Schumaker, and I am the Director of Business Development for Sustainable Power Group LLC ("sPower"). My address is 2180 South 1300 East, Salt Lake City, Utah 84106.

Q. What is sPower?

A. sPower is a renewable energy developer and independent power producer that will have an operating portfolio of over 1.2 GW by the end of 2016, most of which is solar. Roughly 15 percent of our contracts are QF contracts.

Q. On whose behalf are you appearing in this case?

A. I am testifying on behalf of the Ecology Center, the Environmental Law & Policy Center, the Solar Energy Industries Association, and Vote Solar.

Q. Have you testified before this Commission or before any other public service commission?

A. No.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibits A-7 (AS-1) and A-8 (AS-2).

Q. Can you briefly describe your experience in the solar industry?

A. I have been involved in some aspect of the solar industry for over 9 years. After I graduated from the University of Wisconsin, Madison in 2003, I started working as a solar installer. I later went back to graduate school and earned a Masters of Science in Environmental Science with a focus on Energy Technology and Policy from Humboldt State University in Arcata, California. From 2010 through 2012 I worked for the Renewable Northwest Project, which is an organization that advocates for the expansion of environmentally responsible renewable energy resources in the Northwest through collaboration with government, industry, utilities, customers, and advocacy groups. In that position, I studied and evaluated the implementation of PURPA in Oregon, Washington and Idaho with respect to solar QF development. I then spent a year working for a solar engineering procurement and construction group, and in 2013 started at sPower as a Project Manager. In 2015 I was promoted to Director of Business Development at sPower.

Q. What were your responsibilities as a Project Manager at sPower?

A. I was responsible for overseeing solar projects from conception through construction. One important aspect of that responsibility was obtaining successful financing for projects, and I worked directly with lenders and third party tax equity providers to underwrite projects. In underwriting a project, lenders pay particular attention to the provisions of the Power Purchase Agreement, or PPA, with the energy off-taker. I therefore worked closely with the team that was negotiating the PPA to ensure that the PPA they negotiated was financeable. During my time at sPower, I have been responsible for the financing of 100 MW of solar projects. I was also responsible for the acquisition of an additional 65 MW of projects that were already financed.

Q. What are your responsibilities now as Director of Business Development at sPower?

A. I work closely with our power marketing and financing teams to ensure that the projects we are developing and associated PPAs are financeable. I am currently overseeing a development portfolio of 5 GW (5000 MW).

Q. In your experience, what is the role of the PPA in obtaining financing for development of a solar project?

A. The PPA is the centerpiece of project financing. PPAs provide the developer with the cash flows necessary to make debt payments, cover operating expenses, and provide a reasonable return for investors. Lenders look to the PPA in their underwriting process to determine whether a project is financeable, and both the length of the PPA and the certainty of the cash flows are of paramount importance in this process.

Q. In your experience, how does the term of a PPA affect whether it can be financed?

A. One important consideration in obtaining financing is the term of the PPA. Although I have not undertaken an exhaustive survey, based on my experience in the industry I am not aware of any solar project that has been financed and built with a term shorter than 15 years. I consider 15 years to be the shortest PPA term required to make a solar project financeable, although it is not ideal and requires a higher PPA rate than would be required if a 20-year PPA term were offered, thereby burdening ratepayers with additional cost.

Q. Why do longer contract terms make projects more financeable and require lower PPA rates?

A. Generally, debt providers will only lend to a project for the contracted PPA period, and typically subtract an additional two years from the PPA term for amortization purposes. For example, if a project has a 20-year PPA, project debt will be amortized over 18 years, but if a project has a 10-year PPA, project debt will only be amortized over eight years. With that short of an amortization period, annual debt service payments are substantially higher than would be required over an 18-year amortization period, and the project cash flows (i.e. PPA rate) therefore need to be much higher in order to cover debt service.

Q. Have you prepared an analysis of the impact of the PPA term on financing?

A. Yes. Exhibit A-7 (AS-1) contains three tables and one chart to help demonstrate the impact of PPA terms and resulting shorter amortization periods on project financing.

Q. Was Exhibit A-7 (AS-1) prepared by you or at your direction?

A. Yes.

Q. Please explain Exhibit A-7 (AS-1).

A. The analysis is based on a simple financial pro forma for a 20MWAC project using basic assumptions representative of Michigan solar production, capital expenditures (CapEx) and operating expenditures (OpEx). Table 1 identifies all of the assumptions used in the pro forma. The pro forma uses market rate assumptions for the debt interest rate (4.5%), debt service coverage ratio (1.3x EBITDA), and amortization period (PPA length less two years), which are representative of the terms sPower has encountered in securing over $1B of debt on solar projects over the last two years. In order to maintain a simplified analysis, the pro forma assumes that the thirty percent federal Investment Tax Credit (ITC) is fully monetized by the project, as opposed to including third-party tax equity financing. Of particular importance is the amortization period; sPower's experience has been that lenders will only amortize out to two years prior to end of the PPA in order to protect themselves from any shortfall in production or other project shortcomings.

Q. What do Tables 2 and 3 show?

A. Tables 2 and 3 demonstrate the impact of shorter PPA terms on project financing, particularly in regards to the amount of debt that can be secured for a project and how that affects the required equity contribution for a project. Table 2 shows that, when maintaining the same PPA rate ($73.27/MWh), the example 20MW project with a 10-yr PPA will only be able to secure 58% of the amount of debt that can be secured by a project with a 20-yr PPA. This is because project debt with a 10-yr PPA is amortized over 8 years, while project debt with a 20-yr PPA is amortized over 18 years. In both cases the projects have the same Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) profile, so the amount of debt secured by the 10-yr PPA is reduced substantially in order to maintain the 1.3 Debt Service Coverage Ratio (DSCR) required by lenders. With the 20-yr PPA, the 1.3 DSCR requirement is much lower since the debt is amortized over 18 years. Securing less debt on a project increases the required equity contribution and effectively lowers equity returns, thereby hindering the ability of the project to obtain necessary funding.

Q. How do the different contract terms impact solar developers?

A. As indicated in Table 2, financing a 10-yr PPA vs a 20-yr PPA on the example 20MW project would require the developer to contribute roughly $7M of additional equity when compared to the 20-yr PPA, and financing a 15-yr PPA would require an additional $3M when compared to the 20-yr PPA.

Q. Does Table 3 illustrate this impact as well?

A. An alternative way to analyze the same issue is by evaluating the PPA rate required to secure the same amount of debt on a project when assuming a 20, 15 and 10-yr PPA. As seen in Table 3, in order to secure the same amount of debt on the example project with a 20-yr PPA ($16.8M), the 10-yr PPA rate would need to be $113.5/MWh compared to $73.27/MWh on the 20-yr PPA, or 55% greater. This demonstrates the increased EBITDA requirement of shorter term PPAs in order to cover the 1.3 DSCR over a shorter amortization period.

Q. What does Chart 1 show?

A. Chart 1 provides a visual representation of Table 3. The horizontal axis is the operational year of the project. The vertical axis represents dollars per year of EBITDA received under varying PPA terms and debt service payments according to varying amortization periods (designated in the key as "Amort" periods). The EBITDA and Amort amounts decrease over time because the PPA rate does not have an annual escalator, but there is an inflation escalator on the OpEx cost as well as annual solar panel degradation, which result in decreasing ETBIDA over time. The 10-yr PPA EBITDA line corresponds to the 8-year Amort bar, as does the 15-yr PPA EBITDA line with the 13-yr Amort bar and the 20-yr PPA EBITDA line with the 18-yr Amort bar. The 8-yr Amort bar starts at roughly \$2.6M and decreases to \$2.4M over 8 years, compared to the 18-yr Amort which starts at roughly \$1.5M under and decreases to \$1.2M. These amounts represent the debt service payments that need to be made by the project in those years. The EBITDA amounts represent the amount of EBITDA necessary to cover the debt service payments at a 1.3 debt service coverage ratio, as is required by lenders. The chart shows how drastically different the EBITDA requirements are between the varying PPA terms, and therefore how drastically different the PPA rates would need to be to result in the respective EBTIDA amounts. As shown in Table 2, in order to secure the same amount of debt on the project, the PPA rate under a 15-yr PPA would need to be \$85/MWh and \$113.5/MWh under a 10-yr PPA, compared to \$73.27/MWh under the 20-yr PPA.

Q. Does a shorter contract term result in discrimination against QF projects as compared to utility-built generation?

A. In effect, shorter PPA terms result in a developer needing to contribute higher amounts of equity at lower returns or requiring a higher PPA rate in order to meet necessary equity contribution and return levels. Either of these alternatives significantly prejudices QF projects when competing at avoided cost rates which are based on conventional generators that are amortized over 20 years or longer.

Q. Would a shorter PPA with a renewal option make a solar project financeable?

A. Options for renewal are not helpful in obtaining financing, because if the rates under the renewal aren't known at the time of the initial contract, financiers will not underwrite the renewal period. For example, a 10-year PPA with an option for a 10-year renewal would be treated as a 10-year PPA for financing purposes, unless the renewal rates were set at the time of the initial contract and the renewal was at the discretion of the QF.

Q. In your experience, how does the availability of a standard offer impact solar projects?

A. A standard offer gives developers more certainty from the outset and creates an environment in which more developers are willing to take the up-front risks of getting a project started, such as putting down money to secure site control or investing resources in pre-PPA research and development. Negotiating a PPA is a very involved and resource-intensive process and adds on a significant transaction costs. These transaction costs make solar projects more difficult to finance for all QFs up to 20 MW. Reducing transaction costs tends to benefit local developers, who may not have the internal staffing to handle negotiations. Also, having a standard offer contract for up to 20 MW would allow projects to supply power at a lower cost because of the economies of scale that are achieved on larger projects through larger equipment orders and lower average interconnection costs.

Q. Do you have personal experience in how contract terms and availability of a standard offer can impact solar development?

A. Yes. Contract terms and standard offer availability have a real impact on low-cost solar development. For example, North Carolina makes standard offers available for up to 5 MW projects with a contract term of 15 years. The United States Energy Information Administration summarizes the impact of these policies in North Carolina, where there has been $4.4 Billion invested in solar PV projects from 2007 to 2015, the vast majority of which were 5 MW and below solar QFs with standard contracts built in rural areas. See Exhibit A-8 (AS-2). sPower has 65 MW of QF solar projects in North Carolina, all at 5 MW or less with 15 year contracts, but we have not seen similar development in other states with different PURPA implementation policies.

Q. In your experience, are contract terms and the availability of a standard offer important elements in the States' implementation of PURPA?

A. Yes. The availability of longer contract terms and a standard offer for projects up to 20 MW promotes alternative energy resources, diversifies the electric power industry, and serves the public interest. For example, the 15-year contract term and availability of a standard offer has achieved PURPA's goals by allowing solar QFs to provide low-cost renewable energy to ratepayers and by supporting a strong, competitive renewables market in North Carolina. If the standard offer would have been made available to projects up to 20MW and the term increased to 20 years, QF project economics would have been improved and more projects would have been financeable. By making a 20-year standard offer contract available to larger projects, Michigan ratepayers will gain the benefits of the economies of scale and lower transaction costs achieved through 20MW projects as opposed to 5MW projects.

Q. Does that conclude your testimony?

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, establishing the method and avoided cost calculation for **CONSUMERS ENERGY COMPANY** to fully comply with the Public Utilities Regulatory Policy Act of 1978, 16 USC 2601 *et seq.*	))))))	Case No. U-18090

EXHIBITS OF

ADAM SCHUMAKER

ON BEHALF OF

ENVIRONMENTAL LAW & POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, AND VOTE SOLAR

October 27, 2016

Table 1 Pro Forma Inputs	
Constant Assumptions	
Project Size (kWAC Nameplate)	20,000
Project Size (kWDC Nameplate)	25,000
Capacity Factor (based on AC nameplate)	20%
Production (MWh / year)	35040
Solar Panel Degredation (%/year)	0.50%
CapEx Cost Rate ($/kWDC)	$1,500
CapEx Total Cost ($)	$37,500,000
Opex Rate ($/kW-yr)	$30
OpEx Escalator (%/yr)	2%
Investment Tax Credit Rate (%)	30%
Investment Tax Credit Value ($)	$11,250,000
Debt Service Coverage Ratio (DSCR)	1.3
Debt Interest Rate (%)	4.5%
Variable Assumptions	
PPA Term (Years)	20
PPA Rate ($/MWh)	$73.27
PPA Rate Escalator (%/year)	0%
Debt Amortization Period (Years)	18

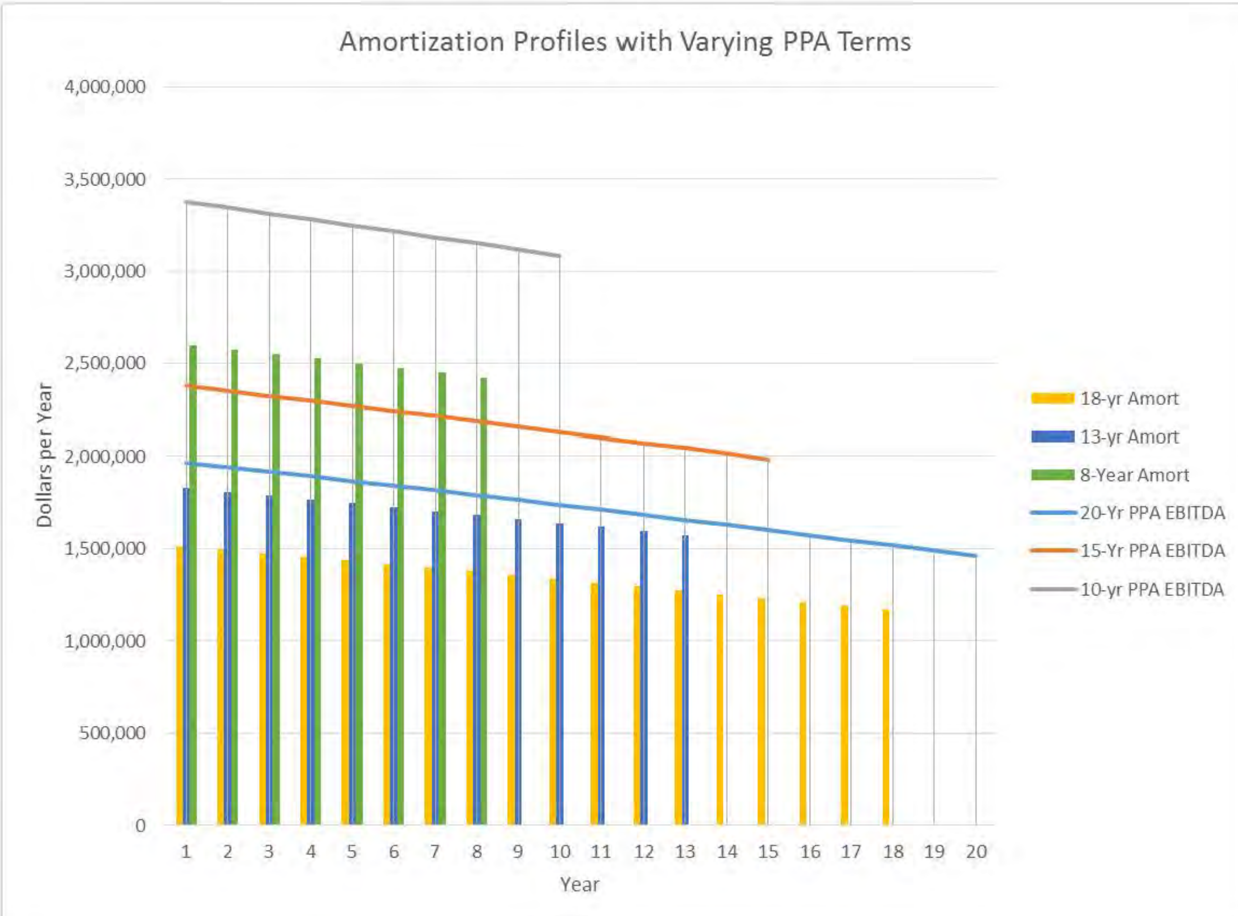
Table 2
Debt Proceeds % of CapEx at Varying PPA Terms

	20-yr PPA	15-yr PPA	10-yr PPA
PPA Rate ($/MWh), 0% Escalator	$73.27	$73.27	$73.27
Total CapEx	$37,500,000	$37,500,000	$37,500,000
Debt Proceeds	$16,756,736	$13,742,965	$9,652,130
Debt Proceeds % of CapEx	45%	37%	26%
ITC % of CapEx	30%	30%	30%
Equity % of CapEx	25%	33%	44%

Table 3
Necessary PPA Rates to Maintain Constant Debt % of CapEx at Varying PPA Terms

	20-yr PPA	15-yr PPA	10-yr PPA
PPA Rate ($/MWh), 0% Escalator	$73.27	$85.00	$113.50
Total CapEx	$37,500,000	$37,500,000	$37,500,000
Debt Proceeds	$16,756,736	$16,747,657	$16,753,161
Debt Proceeds % of CapEx	45%	45%	45%
ITC % of CapEx	30%	30%	30%
Equity % of CapEx	25%	25%	25%

Chart 1


Amortization Profiles with Varying PPA Terms
Dollars per Year
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Year
18-yr Amort
13-yr Amort
8-Year Amort
20-Yr PPA EBITDA
15-Yr PPA EBITDA
10-yr PPA EBITDA

Public Service Commission of Utah

Docket No. 15-035-53, Order

Jan. 7, 2016

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities	DOCKET NO. 15-035-53 ORDER

ISSUED: January 7, 2016

1. PROCEDURAL HISTORY

On May 11, 2015, PacifiCorp, doing business as Rocky Mountain Power ("PacifiCorp"), filed an application with the Commission, requesting approval to modify the maximum contract term for prospective power purchase agreements ("PPAs") with qualifying facilities ("QFs") as that term is used in the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The Application asks the Commission to reduce the maximum term of a QF's PPA ("QF PPA") from 20 to three years.

On May 19, 2015, the Commission held a scheduling conference and issued a Scheduling Order and Notice of Hearing that same date. The hearing was initially set for November 4, 2015 but was subsequently changed to November 12, 2015 by order of the Commission dated August 26, 2015. The following parties sought and were granted intervention in this docket: SunEdison; Sierra Club; Utah Clean Energy ("UCE"); the Renewable Energy Coalition ("REC"); the Rocky Mountain Coalition for Renewable Energy ("RMCRE"); Sustainable Power Group; Summit Wind Power, LLC; Sage Grouse Energy Project, LLC and Ellis-Hall Consultants, LLC.

The Commission received pre-hearing direct written testimony from PacifiCorp, the Division of Public Utilities ("Division"), the Office of Consumer Services ("Office"), REC, RMCRE, Sierra Club and UCE. PacifiCorp, the Division, the Office, RMCRE and REC filed pre-hearing written rebuttal testimony. Finally, PacifiCorp, the Division, the Office, RMCRE and UCE filed pre-hearing written surrebuttal testimony.

The Commission held a hearing on November 12, 2015 at which the following parties appeared: PacifiCorp, the Division, the Office, UCE, RMCRE, REC and Sierra Club. At the conclusion of the hearing, several parties expressed interest in filing post-hearing briefs, which the Commission allowed and required to be filed by December 9, 2015. The Commission subsequently received timely filed post-hearing briefs from PacifiCorp, the Office, the Division, UCE, Sierra Club, RMCRE and REC.

2. BACKGROUND

The Commission administers PURPA and a similar Utah statute that require PacifiCorp to purchase electricity from QFs. *See* Utah Code Ann. § 54-12-2 [hereafter we generally refer to Utah Code Ann. § 54-12-1, *et seq.* as "Chapter 12"]; 16 U.S.C. § 824a-3. Under these laws, PacifiCorp is required to purchase power from QFs at rates equivalent to PacifiCorp's avoided cost. *See* 16 U.S.C. § 824a-3 (using the term "incremental cost" synonymously with what is more commonly termed "avoided cost"); Utah Code Ann. 54-12-2(2). Additionally, federal regulations implementing PURPA offer QFs the option of providing power to PacifiCorp "over a specified term" at prices based on avoided costs calculated "at the time the obligation [to deliver the power] is incurred."[1] 18 C.F.R. § 292-304(d)(2)(ii).

Under existing Commission orders, QFs may require PacifiCorp to enter into 20-year contracts with fixed pricing based on avoided costs calculated at the time of contracting. (*See,*

[1] QFs also have the option of receiving a price based on avoided costs "at the time of delivery." 18 C.F.R. § 292-304(d)(2)(i).

e.g., Report and Order dated October 31, 2005 at 29, *In the Matter of the Application of PacifiCorp for Approval of an IRP-Based Avoided Cost Methodology for QF Projects Larger than One Megawatt*, Docket No. 03-035-14.) In its Application, PacifiCorp asks the Commission to shorten the maximum duration of a QF PPA to three years.

We do not attempt here to identify all of the arguments and evidence the parties have offered in this docket. For context, however, we briefly summarize the positions of those parties who support and oppose the Application.

2.1. PacifiCorp Maintains Its Liability under QF PPAs Has Increased Dramatically Since the Commission Approved 20-Year Contracts and that Continuing to Force PacifiCorp to Enter 20-Year QF PPAs is Inconsistent with its Resource Planning and Acquisition Policies and Practices and Will Subject Ratepayers to Undue Fixed-Price Risk.

PacifiCorp argues that continuing to require it to enter 20-year, fixed-price contracts with QFs unnecessarily subjects ratepayers to significant market risk. (*See, e.g.,* Application at 13.) PacifiCorp represents it "is seeking this modification [in the contract term] at this time as a result of a significant increase in PURPA contract requests received in 2014 and 2015[,] activity that [PacifiCorp] believes will harm customers unless" the maximum contract term is shortened. (*Id.*)

PacifiCorp's witness, Paul Clements, testified that PacifiCorp "had 1,041 megawatts of existing PURPA contracts in Utah and 2,253 megawatts of proposed QF contracts in Utah," totaling "3,294 megawatts of existing and potential Utah QF contracts." (Hr'g Tr. at 14:8-12.) Mr. Clements represented PacifiCorp's average Utah retail load in 2014 was 2,959 megawatts. (*Id.* at 14:13.) Mr. Clements further testified that, system-wide, PacifiCorp was obligated to make $2.9 billion in payments under QF PPAs and that Utah customers are projected to pay

$73.3 million under QF PPAs in 2015. (*Id.* at 14:23-15:2.) Mr. Clements emphasized that payments under QF PPAs are "a major factor in customers' rates." (*Id.* at 15:3-4.)

Mr. Clements further testified that, over the next 10 years, PacifiCorp is under contract to purchase 44.6 million megawatt hours ("MWhs") from QFs at an average price of $64.13 per MWh and that the average forward price curve for the Mid-Columbia wholesale power market trading hub over the same ten years is $26.02 per MWh lower, at $38.11. (*Id*. at 18:20-19:2.) The difference amounts to nearly $1.2 billion over the ten-year period. (*Id.* at 19:3.)

PacifiCorp acknowledges the market could move in the opposite direction, resulting in fixed QF PPA prices that are ultimately below market but contends this observation is irrelevant because, in either event, customers are being forced to bear fixed-price risk to which they would not otherwise be exposed. (*See id.* at 19:13.) PacifiCorp argues, by analogy, that a series of workshops in 2011 and 2012 led to the Commission's adoption of a hedging policy that generally precludes PacifiCorp from entering contracts to hedge natural gas and electricity costs out more than 36 months. (*Id.* at 15:8-25.)[2] PacifiCorp asserts that requiring it to enter into QF PPAs that "lock in" electricity prices for a period of 20 years is inconsistent with the hedging policy and with the rationale underlying the policy.

PacifiCorp also argues that 20-year QF PPA terms are inconsistent with its resource acquisition policies and practices and are not aligned with its Integrated Resource Plan ("IRP") and planning cycle. Mr. Clements explained PacifiCorp "does [not] enter into a long-term transaction unless there is a need identified in the IRP" and notes its "IRP action plan is focused

[2] Mr. Clements acknowledged the hedging policy did not preclude PacifiCorp from entering into long-term power purchases but explained that such contracts require additional stakeholder review. (Hr'g Tr. at 74:17-20.)

only on the next two to four years" because "planning uncertainties grow as you get further out in time." (*Id.* at 20:17-23.) Additionally, PacifiCorp emphasizes it "utilizes a rigorous request for proposal or RFP process whenever it acquires a long-term resource." (*Id.* at 19:21-24, 20:5-7.) By contrast, PacifiCorp does not enter long-term QF PPAs based on any projected need for the power nor are the contracts vetted through the process applicable to other long-term resource acquisitions because PacifiCorp is simply required to purchase the power. (*See id.* at 20:9-10.)

2.2. The Division Generally Shares PacifiCorp's Concerns Regarding 20-Year QF PPAs and Advocates Reducing the Maximum Contract Term to Five Years.

The Division shares PacifiCorp's concern about requiring the utility to purchase limitless quantities of intermittent QF power at prices fixed for 20 years. (*See* C. Peterson Direct Test. at 4:74-5:91.) The Division notes the large spike in existing and proposed QF PPAs and is concerned such a large volume of unplanned, potentially unnecessary QF power could require PacifiCorp "to idle much of its existing fleet during certain times of the day, keep some of it running as back-up and balancing reserves for the intermittent wind and solar resources, and sell excess power into the wholesale markets, possibly at unfavorable prices." (*Id.* at 5:85-90.) The Division concludes such a scenario would not likely "create an efficiently operating electric service system." (*Id.* at 5:90-91.) "The Division does not believe that federal and state policies contemplated the occurrence of unrestrained limitless development of renewable resources." (Hr'g Tr. at 118:25-119:3.)

The Division argues that of the parties opposed to the Application, "none have proposed an alternative solution to the potential problems faced by [PacifiCorp] other than to suggest that low avoided cost pricing would eventually discourage developers." (*Id.* at 118:3-6.) The Division observes that low avoided cost prices should ultimately create a ceiling on the amount of QF power offered to PacifiCorp but represents "it is unknown how much potential capacity might be realized before low prices completely discourage the creation of new supply." (C. Peterson Direct Test. at 5:93-96.) The Division explains that price is not the only variable driving supply: the existence of substantial government subsidies and the downward trending cost of new QF plants also affect supply. (*Id.* at 5:98-6:101.)

The Division disagrees with those parties who assert QF developer financing is a valid consideration in setting a minimum contract term. The Division asserts it is "unaware of any statute or regulation that requires that the Commission ensure that QF projects are economically viable." (*Id.* at 11:213-215.) However, the "Division does recognize that the 20-year term is a benefit to developers and that reducing that benefit will likely reduce development." (Hr'g Tr. at 119:23-25.)

The "Division recommends that the Commission adopt a five-year contract term limit for QFs" but allow parties to propose a longer term if they can show it "is in the public interest under the specific circumstances." (C. Peterson Direct Test. at 20:411-414.) The Division recommends that energy prices be calculated and fixed as they are presently but only for a five-year term. (*Id.* at 20:418-419.) The Division proposes capacity payments be based on "the assumption that the QF will renew its contract through twenty years of service." (*Id.* at 20:417-418.) The Division suggests "[t]his proposal could be viewed as a twenty-year contract with a price reopener every five years, but giving the QF the option every five years to seek higher prices elsewhere." (*Id.* at 20:421-422.) The Division notes that it has generally been opposed to long-term non-QF PPAs because it believes contracts longer than five years are not in the public interest. (C. Peterson Direct Test. at 16:331-17:342.)

2.3. Though the Office Shares Numerous Concerns Raised by PacifiCorp and the Division, the Office Recommends Denying the Application on Legal and Policy Grounds.

The Office shares PacifiCorp's concern about "[t]he risk to ratepayers associated with carrying long-term fixed-price contracts for power" and concedes "[i]t is uncertain whether a 20-year commitment to take all the power these QFs generate and to pay the currently calculated avoided cost prices will end up being a good outcome for ratepayers." (B. Vastag Direct Test. at 2:23-27.) The Office recognizes that "[r]atepayers, not [PacifiCorp], not the QF developer, not the QF financier, carry this risk." (*Id.* at 2:27-28.) The Office also shares PacifiCorp's concern relating to the "disconnect" between "PacifiCorp's system-wide resource planning" and the "significant amount of new long-term QF resources" which "are not being evaluated on a system basis through the [IRP] process." (*Id.* at 2:29-32.) Additionally, the Office acknowledges that "unlike a company-owned resource, QFs cannot be economically dispatched to take advantage of periods when low-priced market purchases of power are available." (Hr'g Tr. at 179:1-4.) The Office also concedes that "forecast error is an issue" with respect to the pricing in a 20-year contract but notes that other issues also exist that impact the accuracy of avoided cost calculations. (*Id.* at 182:22-25.)

Nevertheless, the Office opposes the Application on legal and policy grounds. In its Post-Hearing Brief, the Office argues that FERC regulations require that QF PPA terms be "long enough to insure investor certainty." (Office Post-Hearing Br. at 5.) Additionally, the Office challenges the notion that "ratepayers must be indifferent to any risks associated with the term of a contract," arguing no decision from the Commission or FERC supports the doctrine of ratepayer indifference outside the context of avoided cost pricing. (*Id.* at 2.) In his submitted testimony, the Office's witness Bela Vastag more generally represented the Office is "concerned that this extreme change [in contract duration] may discourage all new QF development," which he asserts "would be contrary to Federal and State laws [that] were enacted specifically to encourage the development of small power producers or QFs." (B. Vastag Direct Test. at 1:13-16 (emphasis removed).)

In light of its legal conclusion that the contract term cannot be shortened, the Office maintains the best remedy available to alleviate the problems associated with a 20-year contract term is to ensure avoided cost modeling is as accurate as possible. (*See, e.g.* B. Vastag Surrebuttal Test. at 2:30-33.)

2.4. Four Intervenors Presented Testimony and Opposed the Application.

2.4.1. RMCRE

RMCRE is an "unincorporated, informal trade group coalition that was formed for the limited purpose of opposing the efforts of [PacifiCorp] in Utah and Wyoming to limit the maximum term of QF power purchase agreements to three years." (*See, e.g.,* H. Isern Direct Test. at 1:14-18.) RMCRE presented three witnesses. First, Kevin Higgins, RMCRE's expert witness, agreed price risk exists with respect to long-term QF PPAs but asserts "there is price risk associated with the acquisition of any long-term resource, including utility resources." (K. Higgins Direct Test. at 8:165-9:167.) Mr. Higgins argues it is not surprising that the average price under existing QF PPAs is higher than the Mid-Columbia average 10-year forward price because "market prices are currently at low levels." (*Id.*at 9:175-179.) Mr. Higgins concedes that "[v]iewed in isolation, long-term fixed price QF contracts might appear to be inconsistent with [PacifiCorp's] financial hedging practices, which are generally limited to 36 months." (*Id.* at 7:130-132.) Mr. Higgins asserts, however, "the more apt comparison is not between [PacifiCorp's] hedging practices and long-term QF contracts, but between long-term QF contracts and [PacifiCorp's] recovery of its generation investments in rate base." (*Id.* at 7:140-143.) Mr. Higgins asserts that "the Company's own generation fleet would not fare well" when compared against the Mid-Columbia ten-year forward price. (*Id.* at 9:185-10:186.)

Next, Bryan Harris, senior development manager for SunEdison, testified "[i]n nearly all cases of which [he was] aware, project financing of QF projects has involved PPAs with much longer terms [than three years], typically twenty years." (B. Harris Direct Test. at 2:43-44.) Mr. Harris represented that "[i]n [his] opinion and experience, a three-year PPA term would almost certainly prevent project financing for almost any new renewable energy project" and "[a]lmost any term length of less than twenty years would make project financing of renewable energy projects very difficult." (*Id.* at 3:48-51.) Mr. Harris testified at hearing, however, that in an environment of higher avoided cost rates, a shorter contract length would be financeable but represented the rates "would need to be significantly higher in order to meet a three-year or a five-year contract term." (Hr'g Tr. at 241:21-242:4.)

Last, Hans Isern, a senior vice president of Sustainable Power Group ("sPower"), which is a developer, financier, owner and operator of QFs, testified that "[i]n virtually all cases of which [he was] aware, project financing of new [QF] projects requires PPAs with terms of twenty years." (H. Isern Direct Test. at 1:6-10; 3:50-51.) Mr. Isern testified sPower has successfully financed projects with 15-year PPAs and that these were in markets with either additional state tax incentives or higher avoided cost prices. (*Id.* at 3:50-55; Hr'g Tr. at 261:6-22.)

As for its legal argument, RMCRE emphasizes Chapter 12's "Legislative Policy," declaring "it is desirable and necessary to encourage independent energy producers to competitively develop sources of electric energy not otherwise available to Utah … and to remove unnecessary barriers to energy transactions involving independent energy producers and electrical corporations." (*See, e.g.,* RMCRE Post-Hr'g Br. at 2 (quoting Utah Code Ann. § 54-12-1).) RMCRE asserts Utah's Legislative Policy "cannot be reconciled" with PacifiCorp's Application (or with the Division's alternative proposal to shorten QF PPAs to five years). (*Id.* at 3.) On the federal side, RMCRE acknowledges "federal laws do not expressly require a 20-year PPA term" but points out "nor do they expressly allow a short-term PPA." (*Id.* at 5.) Recognizing that "FERC regulations allow [state commissions] some 'latitude' in determining how FERC regulations should be 'implemented' by a state," RMCRE asserts "the manner of implementation must be 'reasonably designed to give effect to FERC's rules.'" (*Id.* at 5 (quoting *FERC v. Mississippi*, 456 U.S. 742, 751 (1982).)

2.4.2. REC

REC's director, John Lowe, testified that REC is a coalition of thirty-two members who own and operate over fifty non-intermittent small QFs, generally less than 10 megawatts. (J. Lowe Direct Test. at 4:18-20; Hr'g Tr. at 163:16-19.) REC asks the Commission deny the Application or, alternatively, to except "baseload Schedule 37 eligible QFs" from any change. (J. Lowe Direct Test. at 6:61-64.)

Mr. Lowe "agree[s] that [PacifiCorp] is facing a large number of new contract requests and recently executed contracts" and that "[t]his is a legitimate issue that warrants consideration." (*Id.* at 7:79-81.) Mr. Lowe opines "[m]anaging this problem is a challenge, but does not warrant foreclosing opportunities for small baseload projects that for years have been the heart-and-soul of local PURPA project development." (*Id.* at 7:81-83.)

REC's second witness, Nathan Rich, who is executive director of REC member Wasatch Integrated Waste Management District ("WWMD"), agreed and testified: "I understand the concern that 2,000 megawatts of new QF power would cause a problem to [PacifiCorp.]." (Hr'g Tr. at 168:6-8.) Mr. Rich provided testimony relating to an existing QF project that WWMD operates and a second project it is considering. Mr. Rich testified its existing project operates under an 11-year contract because WWMD did not wish to execute a contract with PacifiCorp that was longer in duration than the contract WWMD has with its primary vendee. (*Id.* at 169:3-10.)

Echoing the Office's arguments, REC maintains a three-year contract term violates PURPA because the federal law and the regulations promulgated under it require QFs be allowed to enter long-term contracts at a fixed price. (REC Post-Hr'g Br. at 4-5.) REC also argues establishing a three-year contract term will deny QFs the opportunity to receive fair capacity value for the electricity they provide. (*Id.* at 6-7.) REC argues that if the Commission is inclined to grant the Application, the Commission should adopt a framework that the Idaho Public Utilities Commission recently implemented whereby QFs who renew their contracts, perhaps repeatedly, after the initial term expires, should be eligible to receive capacity payments based on the time of the original contract. (*Id.* at 8-10.) REC contends "[t]his is consistent with how utilities plan their operations and the benefits that existing QFs provide to the utilities." (*Id.* at 9.)

2.4.3. UCE

UCE offers testimony and arguments that largely parallel the arguments of other intervenors in this docket. In her written testimony, UCE witness Sarah Wright asserted that "[a] three year contract will end the development of renewable QFs in Utah because it will make it impossible for these projects to secure financing." (S. Wright Direct Test. at 5:66-67.) At hearing, Ms. Wright, who is executive director of UCE, suggested this conclusion stemmed from conversations she had with developers, and she deferred detailed questions about the subject to the developer witnesses. (*See* Hr'g Tr. at 194:17-18; 195:5-6.) Ms. Wright also asserts that natural gas prices are near all-time lows and suggests consumers are, therefore, more likely to benefit from long-term prices fixed at currently forecast avoided costs than to be injured by them. (*See, e.g.,* S. Wright Surrebuttal Test. at 10:167-172 (explaining risk associated with natural gas prices is "asymmetrical" in the existing low cost natural gas environment).)

Ms. Wright also asserts that in light of evolving environmental compliance obligations and concerns about climate change, maintaining a 20-year QF PPA contract term constitutes good public policy. (*See id.* at 11:183-12:205.)

2.4.4. Sierra Club

Sierra Club presented energy consultant Thomas Beach as its witness. Like other intervenors, Sierra Club maintains QF developers will be unable to obtain financing under a three-year PPA. (*See, e.g.*, Hr'g Tr. at 205:25-206:2.) Mr. Beach testified that avoided cost pricing leaves ratepayers indifferent "on a forecast basis." (*Id.* at 207:1-12.) Like other intervenors, Sierra Club argues fixed-price generation protects customers against increased prices. (*Id.* at 210:2-3.)

Mr. Beach conceded that a 20-year contract term "reduces the risk of the income stream upon which financing for [QF] projects is based" and that "value [exists] in that reduction in risk to the lenders on [QF] projects." (Hr'g Tr. at 211:19-212:6.) Mr. Beach further conceded such risk is "passed on to customers of the utility" but asserts the consequence is "no different than when the utility builds any kind of plant." (*Id.* at 212:19-23.) Mr. Beach asserts "[t]here's simply no present crisis with an oversupply of renewable QFs in Utah such that the Commission needs to shorten the contract term." (*Id.* at 208:3-6.) Mr. Beach testified the market for QF development will be "self-limiting" as a result of low indicative pricing and the "stepdown" of a federal investment tax credit. (*Id.* at 208:19-209:5.)

3. DISCUSSION, FINDINGS AND CONCLUSIONS

3.1. Federal and State Law are Silent on the Issue of Contract Term, and the Utah Legislature's Policy Statement Does Not Entitle QF Developers to an Unqualified 20-Year Guaranteed Revenue Stream.

Although we appreciate the parties' efforts to strengthen their arguments by reference to Chapter 12, PURPA and FERC orders and regulations, after careful review we are confident no statute or rule prescribes a minimum term for QF PPAs. Federal regulations require QFs have the option to sell electricity "over a specified term" for a price established at the time of contracting, but the rules are silent as to how long the "specified term" must be. *See* 18 C.F.R. § 292.304(d).

The Division argues that, in another context, FERC has determined "contracts of a year or more are sufficiently long-term to meet the statutory requirement that there be 'wholesale markets for long-term sales of capacity and energy.'" (Division Post-Hr'g Br. at 3-4 (quoting

Order No. 688, FERC Stats. & Regs. ¶ 31,233 at P 17).) At the other end of the spectrum, the Office and REC argue FERC regulations require the term be sufficiently long to provide "investor certainty."

We reject the notion federal regulations require QF developers to enjoy "investor certainty." The Office quotes FERC Order 69 out of context in asserting "[t]he purpose behind fixing the avoided cost at the time of the agreement is to provide 'an investor … [the ability] to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.'" (Office Post-Hr'g Br. at 5 (quoting Order 69, FERC Stats. & Regs. ¶ 30,128 at 30,868) (ellipses and brackets in original).) The quoted language falls under a subheading titled "Availability of Electric Utility System Cost Data" that explains FERC's basis for implementing 18 C.F.R. 292.302, which requires utilities to make data available to the public concerning their costs. The quoted language stands for the proposition that prospective QFs must have access to cost data for the purpose of assuring they have the information required to estimate the price (*i.e.*, the "avoided cost") they will receive for their power, not that QF developers have a right to risk-free returns on their investments. (*See* FERC Order No. 69, 45 Fed. Reg. 12,214, 12,218 (Feb. 25, 1980).)[3]

REC makes a similar argument, quoting Order 69 and asserting "[l]ong-term commitments are necessary because QFs have a 'need for certainty with regard to return on

[3] Indeed, this concept is embodied in PacifiCorp's Electric Service Schedule 38 for QF contracting procedures that provides: "[a]n indicative pricing proposal provided by the Company may be used by the QF Developer to make determinations regarding project planning, financing and feasibility. However, such prices are indicative only and may be subject to change by the Company as specified herein or by the Commission. Prices and other terms and conditions are only final and binding to the extent contained in a power purchase agreement executed by both parties and approved by the Commission." Rocky Mountain Power Electric Service Schedule No. 38, State of Utah, P.S.C.U. No. 50, Sheet 38.6.

investment in new technologies.'" (REC Post-Hr'g Br. at 5 (quoting FERC Order No. 69, 45 Fed. Reg. 12,214, 12,224 (Feb. 25,1980).) Here, the quoted language is more pertinent to the issue in this docket, falling under a subheading addressing "[l]egally enforceable obligations" under 18 C.F.R. 292.304. The quoted sentence reads in full: "Many commenters have stressed the need for certainty with regard to return on investment in new technologies." (*Id.*) These commenters were responding to others who argued that "if the avoided cost of energy at the time it is supplied is less than the price provided in the contract … the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers." (*Id.*) FERC goes on to explain that it "does not believe that … [PURPA] was intended to require a minute-by-minute evaluation of costs." (*Id.*) FERC's rejection of the need for "minute-by-minute evaluation of costs" is uncontroversial and logically follows from PURPA's requirement that QFs be allowed to sell their power at prices fixed for a "specified term." We do not read this language in Order 69 as amounting to a requirement, or even endorsement, that avoided cost pricing be fixed for multiple decades.

For its part, Sierra Club acknowledges "FERC does not provide an exact timeframe for the 'specified term,'" but argues FERC regulations require QFs to be compensated for capacity and that "a three or five year contract would not provide a QF compensation for capacity." (Sierra Club Post-Hr'g Br. at 4.) Essentially, Sierra Club argues that if QFs are not permitted to contract into what PacifiCorp calls its "resource deficiency period," *i.e.* the period of time when PacifiCorp's IRP anticipates a need to acquire a new thermal resource, they will be denied capacity value. While we certainly agree the avoided cost methodology must capture avoided capacity costs and ensure QFs are paid for them, we reject the premise that PacifiCorp's anticipated date of acquiring a new thermal resource is dispositive of the contract duration issue. In fact, in multiple recent dockets, the Commission has addressed the issue of capacity value in the so-called "resource sufficiency period" and found that displaced market transactions for firm power capture avoided capacity costs. (*See, e.g.,* Report and Order dated September 18, 2015 at 8-9, *In the Matter of Rocky Mountain Power's Proposed Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities*, Docket No. 15-035-T06.)

Other intervenors, particularly UCE and RMCRE, have strongly emphasized Utah's declared policy "to encourage independent energy producers to competitively develop sources of electric energy … and to remove unnecessary barriers to energy transactions involving independent energy producers and electrical corporations." Utah Code Ann. 54-12-1. We are cognizant of this policy and the policy interests underlying PURPA, but we must advance these policy interests without abdicating our primary duty to ensure the reliability of electric service and to do so "on the basis of reasonable costs." *See Garkane Power Ass'n v. Public Serv. Comm'n of Utah*, 681 P.2d 1196, 1207 (Utah 1984). Nothing in Chapter 12's policy statement suggests guaranteeing QF developers anything less than a 20-year fixed revenue stream will somehow subvert it. While we do not here attempt to draw parameters around how Chapter 12's declared policy ought to influence the Commission's implementation of Chapter 12 or PURPA, we reject the notion that it requires binding PacifiCorp and ratepayers to 20-year fixed prices, irrespective of whether such long-term commitments are otherwise in ratepayers' interest.

In summary, we conclude no federal or state statute or regulation requires a 20-year contract term. As the Supreme Court has observed, FERC regulations "afford state regulatory authorities … latitude in determining the manner in which the regulations are to be implemented." *FERC v. Mississippi*, 456 U.S. at 751; *see also Power Resources Group v. PUC of Texas*, 422 F.3d 231, 238 (5th Cir. 2005) (observing "it is up to the States, not [FERC] to determine the specific parameters of individual QF power purchase agreements….") (quotation omitted). Similarly, Chapter 12 expressly tasks the Commission with "establish[ing] reasonable rates, terms, and conditions" for QF PPAs. Utah Code Ann. § 54-12-2(2). In the absence of additional guidance from the Utah Legislature, Congress or FERC, it falls to this Commission to exercise its discretion to establish a contract term that advances the policy interests underlying PURPA and Chapter 12 without unduly burdening ratepayers with excessive price risk.

3.2. Intervenors Did Not Offer Persuasive Evidence Showing a Reduction in the Minimum Contract Term will Render Their Projects Unviable.

No party has disputed PacifiCorp's representations concerning the volume of power it must purchase under existing QF PPAs, the volume of QF PPAs that have been proposed to PacifiCorp that remain unexecuted and the relative size of these existing and potential obligations in relation to PacifiCorp's total load. Specifically, at the time it filed the Application, PacifiCorp had 1,041 nameplate megawatts of existing PURPA contracts in Utah, which constitutes more than a third of its 2014 average Utah retail load, and 3,294 total nameplate megawatts of existing and potential Utah QF contracts. (Hr'g Tr. at 14:8-13.). If all of the proposed QF contracts came to fruition, the nameplate megawatts of the QF power would alone surpass, by a considerable margin, Utah's average retail load requirements. (*Id.*) The cost to ratepayers is significant: PacifiCorp is currently obliged on a system-wide basis to pay \$2.9 billion under QF contracts over the next 10 years, and Utah ratepayers will be accountable for \$73.3 million in payments under QF PPAs in 2015 alone. (*Id.* at 18:19-19:2.) Finally, although we recognize and accept that avoided cost projections used to establish prices at the time of contracting may deviate from the actual avoided costs at the time of delivery, we are mindful that over the next 10 years the average price PacifiCorp is obliged to pay per MWh under existing QF PPAs significantly exceeds the projected market price. (*See id.*)

Nevertheless, intervenors and the Office ask the Commission to deny the Application based on their assertion that a reduction in contract duration will make financing unavailable and thereby preclude new QF development and defeat the policies underlying Chapter 12 and PURPA. As an initial matter, as we believe the discussion above makes clear, we do not read Chapter 12, PURPA or any FERC regulation to require ratepayers to subsidize QF projects to make them profitable for investors. However, even if it were incumbent on the Commission to establish contract terms that ensured the ability of QF developers to obtain financing, the record does not demonstrate QF developers will be unable to obtain financing on projects with shortened contract terms.

To be clear, we do not doubt QF developers may be able to negotiate more favorable financing with a longer guaranteed revenue stream, but the record does not substantiate the claim that a reduction in contract term will render them unable to obtain financing. It seems to us, assuming arguendo that the Commission has an obligation to ensure economic viability of QF projects, the primary question would not be whether financing will be available but rather how the terms of financing are likely to change if the duration of guaranteed revenue is reduced and whether, in light of those changes, projects can be economically viable.

While PacifiCorp's books are open to us, the Commission has no information pertaining to the finances of QFs. We are not suggesting we are entitled to such information, but the argument that financing will not be available is not compelling absent supporting evidence. No party presented information in this docket attempting to quantify the impact a change in contract term would have on financing terms and, by extension, on the viability of future QF projects. The intervening developers might have, for instance, presented testimony and exhibits (in summary fashion or otherwise) illustrating the finances of a sampling of developments in an effort to demonstrate that less favorable credit terms would have rendered them uneconomic. They did not do so. Rather, the only evidence in the record to support the assertion that projects will not be financeable absent a 20-year contract is conclusory testimony from QF development executives, their consultants or renewable energy advocates. Even if we recognized a legal obligation to ensure QF projects are financeable, a principle we have not adopted here, we would be disinclined to rely solely on these conclusory representations as a basis to continue to impose on ratepayers the risks inherent in 20-year contracts.

3.3. While the Commission Shares PacifiCorp's and the Division's Concern that 20-Year Contract Terms Expose Customers to Undue Fixed-Price Risk, the Commission Finds the Balance of Policy Interests Favors a More Gradual Reduction in Contract Duration.

Although we find the record supports taking action to protect ratepayers against undue fixed-price risk, we believe a more measured response is appropriate than either the 85 percent reduction for which PacifiCorp advocates or the 75 percent reduction sought by the Division. Based on the information available to us at this time and the record in this docket, we believe and find the public interest will best be served by a five-year reduction, establishing a maximum contract term of 15 years.

While no party specifically advocates for a 15-year contract term, evidence in the record supports our finding. RMCRE witness Hans Isern testified that his employer, sPower, has successfully financed projects with 15-year contract terms, though he qualified his testimony by adding these projects were developed in states with “other incentives” or high avoided cost prices. (Hr’g Tr. at 261:6-22.) Similarly, Bryan Harris, testifying for SunEdison, acknowledged that there are markets in the United States where contract terms are limited to 15 years. (*Id.* at 254:16-255:11.) Mr. Harris qualified his testimony by adding those markets were more “liquid” than Utah and that developers can “readily sell the power from those projects.” (*Id.*) However, we note developers in Utah can reasonably anticipate the opportunity to continue to sell power to PacifiCorp or to some other purchaser — albeit at updated avoided cost or market prices — after the initial contract term expires.[4] Although evidence in the record supports our decision, it should be understood that our determination ultimately constitutes an exercise of our discretion. We have endeavored to balance our competing obligations to advance the policies underlying Chapter 12 and PURPA while protecting ratepayers from unreasonable costs. We believe a 15-year term strikes the appropriate balance at this time by mitigating a fair portion of the fixed-price risk ratepayers would otherwise bear while allowing QF developers and their financiers a reasonable opportunity to adjust to this more modest change in business practice.

For all of these reasons, we conclude it is just, reasonable and in the public interest to require PacifiCorp to enter QF PPAs of no longer than 15 years in duration.

[4] We also take administrative notice that the federal investment tax credit was extended subsequent to the hearing in this matter, which undermines the testimony that the expiration of the tax credit will serve as a “self-limiting” factor in the QF market. (*See* Consolidated Appropriations Act of 2016, H.R. 2029, 114th Cong. § 301, *et seq.* (2015); Hr’g Tr. at 208:19-209:5.)

4. ORDER

PacifiCorp's Application is granted in part and denied in part. In a manner consistent with all otherwise applicable Commission orders, tariffs, statutes and regulations, PacifiCorp shall enter into purchase agreements with qualifying facilities for a duration not to exceed 15 years. This Order does not alter the terms of existing QF PPAs, but existing QF PPAs will be subject to the 15-year limit after their current term expires. As a general matter, this Order applies to any QF that has not executed a PPA with PacifiCorp as of the date of this Order. In the event a PPA has not been executed as of the date of this Order but a party nevertheless believes it possesses a legally enforceable obligation as of the date of this Order that entitles the party to a 20-year contract term, the party may submit the circumstances for Commission review. Such review will be fact-specific and conducted on a case-by-case basis.[5]

DATED at Salt Lake City, Utah, this 7th day of January, 2016.

/s/ Thad LeVar, Chair

/s/ David R. Clark, Commissioner

/s/ Jordan A. White, Commissioner

Attest:

/s/ Gary L. Widerburg
Commission Secretary
DW#271270

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[5] We have not had occasion to consider the issue of whether and how a party might establish a legally enforceable obligation prior to execution of a written contract pursuant to the applicable tariff. However, we recognize parties may bring disputes before the Commission with respect to this issue to the extent they arise.

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the Commission within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the Commission fails to grant a request for review or rehearing within 20 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the Commission's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code Ann. §§ 63G-4-401, 63G-4-403, and the Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on the 7th day of January, 2016, a true and correct copy of the foregoing was served upon the following as indicated below:

By Electronic-Mail:

Data Request Response Center (datarequest@pacificorp.com)
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Yvonne R. Hogle (yvonne.hogle@pacificorp.com)
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____
Administrative Assistant

Public Service Commission of Wyoming

Docket No. 20000-481-EA-15, Order

Jun. 23, 2016

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR MODIFICATION OF CONTRACT TERM OF PURPA POWER PURCHASE AGREEMENTS WITH QUALIFYING FACILITIES	)))))	DOCKET NO. 20000-481-EA-15 (RECORD NO. 14220)

APPEARANCES

For the Applicant, Rocky Mountain Power (RMP or the Company):
YVONNE R. HOGLE, Corporate Counsel, Salt Lake City, Utah.

For the Office of Consumer Advocate (OCA):
CHRISTOPHER LEGER, Counsel, Cheyenne, Wyoming.

For the Intervenor, Wyoming Industrial Energy Consumers (WIEC):
ABBY BRIGGERMAN, Counsel, Holland & Hart, LLP, Greenwood Village, Colorado.

For the Intervenor, Northern Laramie Range Alliance (NLRA):
CRYSTAL J. McDONOUGH, Counsel, Pathfinder Law Offices, LLC, Loveland, Colorado.

For the Intervenor, Renewable Energy Coalition (REC):
IRION SANGER, Counsel, Sanger Law P.C., Portland, Oregon.
HARRIET M. HAGEMAN, Local Counsel, Hageman Law, P.C., Cheyenne, Wyoming.

For the Intervenor, Rocky Mountain Coalition for Renewable Energy (RMCRE):
GARY DODGE, Counsel, Hatch James, & Dodge, Salt Lake City, Utah.
HARRIET M. HAGEMAN, Local Counsel, Hageman Law, P.C., Cheyenne, Wyoming.

For the Intervenor, Chevron Power and Energy Management Company,
a division of Chevron U.S.A. Inc. (CPEM):
JARED JOHNSON, Senior Counsel, Houston, Texas.

HEARD BEFORE

Chairman ALAN B. MINIER
Deputy Chairman WILLIAM F. RUSSELL

LORI L. BRAND, Assistant Secretary,
Presiding pursuant to a *Special Order* of the Commission.

MEMORANDUM OPINION, FINDINGS OF FACT, DECISION AND ORDER
(Issued June 23, 2016)

This matter is before the Wyoming Public Service Commission (Commission) upon the Application of RMP requesting authority to modify the contract term of its Public Utility

Regulatory Policies Act of 1978 (PURPA) Power Purchase Agreements (PPA) with Qualifying Facilities (QFs) and on the interventions of the OCA, WIEC, REC, RMCRE, EverPower Wind Holdings, Inc. (EverPower), NLRA and CPEM (collectively, with RMP, the Parties).

The Commission, having reviewed the Application and respective attached exhibits, the Parties' and Intervenors' prehearing filings, the evidence introduced at the public hearing held on March 29-30, 2016, its files regarding RMP, applicable Wyoming utility law, having heard the arguments of the Parties, and otherwise being fully advised in the premises, FINDS and CONCLUDES:

Introduction

1. RMP is a public utility, as defined in Wyo. Stat. § 37-1-101(a)(vi)(C), providing retail electric public utility service under certificates of public convenience and necessity issued by the Commission. RMP is subject to the Commission's jurisdiction pursuant to Wyo. Stat. § 37-2-112. RMP is a division of PacifiCorp, an Oregon Corporation, which provides electric service to retail customers through its RMP division in Wyoming, Utah, and Idaho, and through its Pacific Power division in Oregon, California and Washington. (Ex. 1, p. 2).

2. On August 26, 2015, the Company submitted an Application together with testimony and exhibits requesting authority to modify the contract term of its PURPA PPAs with QFs.[1] Specifically, RMP requested the Commission issue an order approving a reduction of the maximum contract term of prospective PPAs with QFs under PURPA from 20 to three years consistent with the Company's hedging and trading policies and practices for non-PURPA energy contracts, and to align with its Integrated Resource Plan (IRP) cycle. The Company also requested approval to modify its avoided cost Partial Displacement Differential Revenue requirement (PDDRR) methodology to reflect all active QF projects in the pricing queue ahead of any newly proposed QF requests for indicative pricing. (Ex. 1, pp. 14-15). RMP included with its Application the supporting prefiled testimony and exhibits of two witnesses: Paul H. Clements, RMP Director, Commercial Services (Exs. 2-2.1); and, Brian S. Dickman, RMP Director of, Net Power Costs & Load Forecasting. (Ex. 3).

3. In its application, RMP stated it is necessary to reduce the maximum contract term for PURPA contracts from 20 to three years due to a dramatic increase in QF pricing requests it has received in 2014 and 2015. (Ex. 1, p. 7). RMP asserted the current Commission approved PURPA contract length puts retail customers at risk of harm due to significant and unnecessary exposure to long-term price risk. (Ex. 1, p. 9). Further, RMP stated that the 20-year maximum QF contract term is inconsistent with the hedging policy put in place as a direct result of input from the Company's stakeholders. (Ex. 1, p. 10). According to RMP, this change will uphold the "ratepayer indifference standard" under PURPA and protect Wyoming customers. (Ex. 1, p. 15).

4. On August 27, 2016, the Commission issued a *Suspension Order* suspending the proposed filing for investigation and further action for the initial six-month period pursuant to

[1] As discussed further below, while the applicable statutes and rules are matters of federal law, PURPA gives state commissions the responsibility to determine a utility's avoided costs as well as the terms and conditions of PURPA contracts, so long as those terms are consistent with federal law.

Wyo. Stat. § 37-3-106(c), which commences after the 30-day notice term provided in subsection (b) thereof. (Ex. 100).

5. On August 28, 2015, the Commission issued a *Notice of Application* which generally described the Application and provided a deadline of September 28, 2015, for interested persons to file a statement, intervention petition, protest, or request for a public hearing. A public notice was published in newspapers in RMP's service territory. (Ex. 101).

6. On August 31, 2015, the OCA, a separate, independent division of the Public Service Commission charged with representing the interests of Wyoming citizens and all classes of utility customers filed its *Notice of Intervention*, pursuant to Wyo. Stat. § 37-2-401. (Ex. 102).

7. On September 23, 2015, NLRA, a citizens' group with members who are residents of Wyoming, filed a *Petition for Leave to Intervene*.

8. On September 28, 2015, WIEC, an unincorporated association comprised of large industrial customers, filed a *Petition for Leave to Intervene and Request for Hearing*. Also on this day, OCA filed a Request for Hearing (Ex. 103); CPEM filed its *Petition for Leave to Intervene and Comments*; and REC and RMCRE filed *Petitions for Leave to Intervene and Request for Hearing.*

9. On October 7, 2015, the Commission issued orders authorizing the interventions of NLRA, WIEC, CPEM, REC and RMCRE. (Exs. 104, 105, 106, 107, and 108).

10. On October 7, 2016, EverPower filed its *EverPower Wind Holdings, Inc.'s Late Petition for Leave to Intervene and Request for Hearing*. EverPower's Petition was granted by *Order Authorizing Late Intervention* issued on October 16, 2015. (Ex. 110).

11. On October 9, 2015, the Commission issued a *Special Order Authorizing One Commissioner and/or Presiding Officer to Conduct Public Hearing*. (Ex. 109).

12. On October 9, 2015, RMP filed a *Petition for Confidential Treatment and Protective Order (Petition)*. The Commission granted the *Petition* and issued a *Protective Order* on October 26, 2015. (Ex. 112). Subsequently, WIEC, NLRA, RMCRE, EverPower, REC and CPEM filed their respective Exhibits A to Protective Order.

13. On October 19, 2015, REC filed a *Motion for Admission Pro Hac Vice* of Irion Sanger; and EverPower and RMCRE filed a *Motion for Admission Pro Hac Vice* of Gary Dodge (collectively *Motions*). The *Motions* were granted by *Orders Granting Motion for Admission Pro Hac Vice* issued on November 6, 2015. (Exs. 113 and 114).

14. On October 22, 2015, the Commission issued a *Scheduling Order* establishing the procedural schedule and setting a public hearing to commence on March 29, 2016. (Ex. 111).

15. On November 9, 2015, WIEC filed a *Motion for Application for Admission of Pro Hac Vice of Robert M. Pomeroy, Jr. and Thorvald A. Nelson* (*Motions*). The *Motion* was granted by an *Order Granting Motion for Admission Pro Hac Vice* issued on November 24, 2015. (Ex. 115).

16. On February 29, 2016, the Commission issued a *Notice and Order Setting Public Hearing* for March 29, 2016. A public notice was published in newspapers in RMP's service territory. (Ex. 116).

17. Pursuant to the *Scheduling Order*, the OCA, WIEC, NLRA, REC, RMCRE and CPEM filed the direct testimony of their witnesses on January 4, 2016; RMP filed its rebuttal testimony on January 29, 2016; NLRA and REC filed cross answer testimony; and RMCRE, WIEC and CPEM filed Joint Confidential and Non-Confidential cross answer testimony on January 29, 2016.

18. On March 28, 2016, RMCRE filed a *Motion to Present Witness Testimony by Telephone*. Also on this day, RMCRE, REC and EverPower filed a *Motion to Excuse Attendance of Local Counsel*.

19. On March 29, 2016, the exhibit conference was held and the following exhibits were received into evidence:

- RMP's Exhibit Nos. 1.0 through 15.0. (Tr. Vol. I, p. 23).
- PSC Exhibit Nos. 100 through 172. (Tr. Vol. I, pp. 11 and 16).
- OCA Exhibit Nos. 200 through 200.3. (Tr. Vol. I, p. 24).
- WIEC Exhibit Nos. 300 through 318. (Tr. Vol. I, p. 25).
- NLRA Exhibit Nos. 400 through 403. (Tr. Vol. I, p. 26).
- RMCRE Exhibit Nos. 600 through 607, 609 through 611 and 613 through 621. (Tr. Vol. I, p. 32).
- REC Exhibits Nos. 700 through 716. (Tr. Vol. I, p. 33).

20. The public hearing was held March 29-30, 2016, pursuant to the Wyoming Administrative Procedure Act, Wyo. Stat. § 16-3-101, *et seq*. (WAPA). Paul H. Clements and Brian S. Dickman testified for RMP. Belinda J. Kolb, Ph.D. testified on behalf of the OCA. Kenneth G. Lay and Laura Ladd testified on behalf of NLRA. John R. Lowe, testified on behalf of REC. Kevin C. Higgins, Michael J. Speerschneider, and Hans Isern testified on behalf of RMCRE. RMP Exhibit 16 was also received into evidence. (Tr. Vol. I, p. 99).

21. At the conclusion of the hearing, the Commission requested post-hearing briefs be filed by April 19, 2016. (Tr. Vol. II, p. 513).

22. On April 15, 2016, WIEC, CPEM, RMCRE, EverPower and REC filed a *Joint Motion to Take Administrative Notice of a Rocky Mountain Power Filing and Admit Late-Filed Exhibits (Joint Motion)*. The *Joint Motion* was considered at a noticed special open meeting on April 22, 2016, immediately preceding public deliberations. It was denied by the Commission, which issued its written *Order* on May 31, 2016.

23. On April 19, 2016, OCA, REC, RMP and NLRA filed their respective *Post Hearing Briefs*; and WIEC, RMCRE, CPEM and EverPower filed a *Joint Post Trial Brief*.

24. The Commission held public deliberations on April 22, 2016, pursuant to Wyo. Stat. § 16-4-403. The Commission then directed the preparation of an order consistent with its decision.

Summary of Decision

25. The Commission denies RMP's Application for authority to amend Schedules 37 and 38 to reduce the contract term of its PURPA PPAs with QFs from 20 years to three years. The Commission concludes that RMP failed to meet its burden to demonstrate that the proposed modification of the Wyoming PPA contracts is reasonable, will solve an alleged system-wide problem, and is in the public interest of Wyoming ratepayers. Rather than approving the pending application, the Commission directs the Company to initiate a collaborative process with relevant stakeholders to address substantive and procedural reforms to Wyoming's PPA process and PDDRR avoided cost methodology. In this context, the Commission denies the Company's request to modify its avoided cost PDDRR methodology described in Schedules 37 and 38 to reflect all active QF projects in the pricing queue ahead of any newly proposed Wyoming QF requests for indicative pricing on a similar basis, and leaves this approach for consideration in the collaborative process.

Contentions of the Parties and Resulting Issues

26. RMP requests to decrease its maximum QF contract term from 20 years to three years for all contracts executed under both Schedules 37 and 38. The Company contends the 20-year pricing requirement artificially inflates its avoided cost pricing for QFs leading to higher rates for Wyoming customers and unnecessary exposure of RMP to long-term price risk. It asserts this result violates PURPA's "ratepayer indifference standard." RMP indicates it is experiencing a large increase in QFs in the queue, which coupled with the long-term duration of the contracts, increases fixed price risks to Wyoming ratepayers. (Ex. 2, pp. 1-2) RMP seeks to align the contract duration with its 36-month hedging policy and its two-year IRP planning cycle. According to the Company, aligning the QF contract duration would ensure pricing remains consistent with the most current information regarding RMP's resource needs. (Ex. 1, pp. 13-14). RMP contends its request will not eliminate the "must purchase" obligation of PURPA; rather, the QF PPA's would be re-negotiated every three years and would include the avoided cost pricing current at that time. (Tr. Vol. I, pp. 209-211).

27. RMP also requests to modify its avoided cost PDDRR methodology calculation to include "indicative pricing" for QF contracts to reflect *all* Schedule 38 QFs in the queue. Indicative prices are preliminary estimates of avoided cost rates; they serve as the starting point for negotiations between QFs and a utility. Indicative prices may differ from the final prices in a contract (i.e., contract prices). The current PDDRR methodology used by the Company recognizes only executed QF contracts in the calculation of the avoided cost. All other *proposed* (queued) QFs are not included in the calculation process. The Company requests to incorporate the *proposed* QF projects into the calculation of the avoided cost, arguing it will more accurately reflect the avoided cost of the displaced resources. RMP states that if the queued QFs are ignored in this calculation process the PDDRR calculation results in payments to QFs that exceed the avoided cost. (Ex. 3, pp. 3-4).

28. NLRA supports the Company's request to decrease the maximum term of the QF contracts. NLRA asserts long-term, fixed-price contracts are not in the interest of ratepayers. (Ex. 401, p. 5). It cites *Exelon Wind 1, LLC v. Nelson*, 766 F.3d 380 (5^{th} Cir. 2014), for the proposition there is no obligation for utilities to enter into long-term fixed-price contracts for non-firm energy and the ratepayer indifference standard precludes it. (Ex. 401, p. 6). NLRA argues PURPA contracts should be five years or less, straightforward and based on a rigorous IRP process. (Ex.

401, pp. 13 and 16). As an alternative, NLRA supports a 20 year contract with avoided cost pricing review (and potential adjustment) every three years. (Ex. 402, p. 27).

29. On the issue of modifying the avoided cost pricing methodology, NLRA asserts that because of the substantial increase in QF in the queue, RMP's current methodology does not accurately reflect the pricing of displaced resources. (Ex. 401, p. 6). It also states if FERC has ruled that indicative pricing alone is sufficient to create a legally enforceable obligation, it is appropriate to include all active QFs contracts in the queue when calculating indicative pricing for a prospective QF. (Ex. 401, p. 17). NLRA further contends that if the Commission approves the application, it should apply the requested new policy to all QFs that have not yet begun substantial physical construction and require RMP make compliant any QF contracts for facilities that are not in service on or before the date of the Commission decision. (Ex. 400, p. 10).[2]

30. REC opposes the Company's application and requests the Commission to deny it. It contends a minimal PPA term would cause significant and unnecessary harm to RMP's ratepayers and QF projects; and that three year contract terms will make it impossible for new QFs to obtain financing and could jeopardize the operations of some existing QFs. (Ex. 700, pp. 3-4).

31. REC additionally contends that small QFs covered under Schedule 37 should be exempt from any changes requested by RMP because it is difficult for small QFs (Schedule 37) to negotiate contracts. In the alternative, if the contract term for Schedule 37 is shortened, all small projects as well as all existing projects seeking a replacement of a firm contract should continue to receive capacity payments or value for capacity. REC also recommends Schedule 37 be clarified for application to seasonal hydro projects. REC states the capacity factors for seasonal hydro should be calculated on actual seasonal production basis, rather than annually to account for the capacity benefits provided by such projects. (Ex. 700, pp. 4-5).

32. OCA opposes the Company's application and recommends RMP's requests be denied. It contends that RMP has not sufficiently made its case for the requested changes. It argues decreasing the contract term is anti-competitive, and will do nothing to mitigate higher avoided cost contracts signed in the past. (Ex. 200, p. 7).

33. OCA further contends that a reasonable standard for determining the optimal PPA contract length would be to consider the amount of time that the utility owned plant assets are typically in rate base. OCA suggests there could be alternatives to the contract change requested by the Company such as tiered megawatt thresholds where the first tier is offered 20-year pricing, the next tier offered ten-year pricing in the third tier offered three-year pricing. The tiered alternative could include a provision for a time certain for completion of the project. If a project is not completed, it would forfeit the 20-year pricing. (Ex. 200, p. 9).

34. As to modifying the avoided cost methodology, OCA recommends including 50% of the PPAs that are in a specified final contract phase in the avoided cost calculation. It also suggests an alternative under PURPA where utilities are not required to make QF purchases under "appropriate operational circumstances." Like REC, OCA argues it is unnecessary to change the contract length of Schedule 37 QF PPAs because small QFs are not materially contributing to the problem the Company alleges. (Ex. 200, pp. 15-16).

[2] RMP repudiated the NLRA approach to existing PPA contracts in its Rebuttal testimony. (Ex. 2.2, pp. 28-29).

35. WIEC, RMCRE, and CPEM oppose RMP's Application and request it be denied. They jointly contend the Company's proposal is neither reasonable nor in the public interest. (Ex. 600 p. 4). They point out that the fixed-price risk decried by RMP operates in both directions. QFs with PPA contracts must absorb the cost of future upgrades and other investments without recourse to additional ratepayer funding, and so may yield a benefit to ratepayers instead of a subsidy to QFs. (Ex. 600, pp. 8-10 and 14-15).

36. As to decreasing the maximum QF contract term, these Intervenors jointly contend that QF PPA contracts should *not* be compared to RMP's hedging practices, and that the more appropriate analogy is to recovery of RMP's generation investment in rate base. (Ex. 600, pp. 8-10).

37. With regard to the requested changes to the avoided cost methodology, WIEC, RMCRE, and CPEM contend that the current PDDRR methodology meets RMP's stated objective of ratepayer indifference, and may actually underprice the avoided cost. These parties contend the current methodology correctly calculates avoided costs by including only QFs with executed contracts in the resource stack, and by requiring indicative pricing to be updated when a new queue of contracts are executed. (Ex. 600, pp. 20-22).

38. These parties also contend the calculation methodology proposed in RMP's application will result in avoided costs that are too low. The proposed indicative pricing would accordingly drive down the prices offered to Wyoming QFs. (Ex. 600, pp. 22-23). Generally, they assert that in making its proposal, RMP overreacted to FERC decisions relating to "legally enforceable obligations" that were applied to a different set of facts than exist in Wyoming. (Ex. 600, pp. 23-25).

39. Lastly, they contend RMP's proposal will have a negative impact on renewable energy developers, is anti-competitive, and will suppress QF development in Wyoming at a time when implementation of the Clean Power Plan (CPP) is already creating uncertainty. (Exs. 600, pp. 15-16; 601, pp. 2-3; and 602, pp. 2-3).

Findings of Fact

Reduction of PPA Contract Term to Three Years

40. RMP applied for approval to decrease its maximum QF contract term from 20 years to three years under both Schedules 37 and 38. RMP witness Paul Clements testified the change is necessary to: [1] maintain PURPA's "ratepayer indifference standard;[3] [2] be consistent with RMP's hedging and trading policies for non-PURPA contracts; and [3] align with the Company's IRP. (Ex. 2, pp. 1-2).

[3] PURPA mandates that a utility must purchase energy and capacity from a QF at the same price it would have to pay if it otherwise purchased or generated the energy or capacity on its own. This requirement is commonly termed the "ratepayer indifference standard." It means ratepayers should be economically indifferent to the source of the utility's energy by ensuring the cost to the utility purchasing from a QF does not exceed the cost it would incur if it were purchasing from another source.

Background

41. The Commission last addressed the subject of the maximum RMP QF contract term in Docket No. 20000-388-EA-11 (Record No. 12750). In that case, RMP submitted its application for Commission approval to implement a permanent avoided cost methodology in Wyoming for QFs that do not qualify for Wyoming Schedule 37 – Avoided Cost Purchases from Qualifying Facilities. In Sub 388, the Company stated that, pursuant to the settlement agreement approved in Docket No. 20000-342-EA-09 (Sub 342), it had completed evaluation and reconsideration of its current pilot program avoided cost methodology and was requesting approval of its proposed permanent avoided cost methodology, which it said was essentially the same methodology approved in Sub 342, with minor modifications. (Sub 388 Application, p. 4, ¶ 5). The Company stated approval of its proposed permanent avoided cost methodology would allow the Company to offer avoided cost prices to QFs of less than 100 MW[4] in a manner that would encourage the development of cost-effective QFs without creating subsidies for existing or new retail customers. (Docket No. 20000-388-EA-11 (Record No. 12750), *Memorandum Opinion, Findings and Order* issued November 4, 2011 (2011 *Order* ¶ 1).

42. Sub 388 had multiple intervening parties and was fully litigated in contested case proceedings. In its 2011 *Order*, the Commission rejected Intervenor proposals to allow for maximum contracts in excess of the 20 years requested. (2011 *Order* at ¶ 62). The Commission noted that RMP witness Gregory N. Duvall, PacifiCorp's then Director Net Power Costs, addressed Intervenor recommendations for contract terms of greater than 20 years where the QF could demonstrate the technology it used had an expected life consistent with a longer-term contract. Duvall expressed the Company's support for a contract term of 20 years, stating that similar contract lengths were allowed in its other jurisdictions. He argued that the proposal for longer-term contracts would place additional risk on retail customers and was not necessary for the development of new QF facilities. In view of the uncertainties facing the electric industry at the time, Duvall expressed his belief that locking in current prices for power deliveries occurring over a 40 year future period would not be a reasonable policy. (*Id.* at ¶ 22).

43. In its 2011 *Order*, the Commission found that all Parties supported adoption of the proposed Schedule 38, which generally codified the Sub 342 *Stipulation,* but liberalized it and provided greater flexibility to the process by removing the 50 MW per year limitation for wind QFs and allowing PPAs with 20-year terms for all QFs. (2011 *Order* at ¶ 58). The Commission found the provisions contained in Schedule 38 also provided the flexibility requested by Intervening parties by: [1] giving the negotiating parties the leeway to agree on specific terms and conditions beyond those described in Schedule 38, and [2] acknowledging the Commission's continuing authority to review proposed contracts, including those containing terms that may vary from those in the standard contract. The Commission noted that Schedule 38 contained a provision, applicable when RMP and the potential QF provider were unable to come to agreement, requiring them to try for 60 days to work out their differences before bringing the issue to the Commission. Finally, the Commission noted a reasonably applied Schedule 38 may assist QFs in obtaining a contract which could support project financing. (*Id.* at ¶ 58).

44. In its 2011 *Order*, the Commission stated that it shared RMP's concern that allowing extended contract terms, in some cases up to 40 years, had the effect of locking ratepayers

[4] 80 MW in the case of wind QFs.

into paying set prices for a 40-year period, which would not be the case with a utility-owned facility. Based on this "lock-in" possibility, the Commission found a QF contract with a term length beyond 20 years may be unwise and may expose the Company and its customers to enhanced risk. The Commission noted in past avoided cost dockets, that longer-term QF contracts were advanced on the idea that a 20-year contract would provide insufficient security for the QF developer to obtain project financing. (*Id.* at ¶ 62).

45. The Commission ultimately found the evidence presented in the case demonstrated wind QF facilities were being developed in Wyoming under PPAs with RMP having 20-year terms, which supported a finding that 20-year contract terms were adequate for obtaining QF project financing. The Commission continued that "these facts notwithstanding, if a thermal QF developer wished to argue, and could successfully demonstrate, that the generation technology chosen for the proposed QF facility has a reasonable life expectancy greater than 20 years, this demonstration and argument should be made during negotiations between the QF provider and RMP under the procedure provided for in Schedule 38." The Commission reminded the parties that absent agreement, "disputes can be brought before the Commission for consideration under the 60-day provision." Thus, "satisfied that the argument for a longer term may be made and fairly considered," the Commission held "it would not require a provision in Schedule 38 that specifically provided for contract terms of longer than 20 years." (*Id.*).

Potential Fixed-Price Risk to Ratepayers

46. RMP asserts the 20-year pricing requirement artificially inflates its avoided cost pricing for QFs leading to higher rates for Wyoming customers and exposes RMP to unnecessary long-term price risk. It contends this result violates PURPA's "ratepayer indifference standard." RMP testifies it is experiencing a large increase of QFs in the system-wide pricing queue, which coupled with the long-term duration of the contracts, increases fixed-price risk to Wyoming ratepayers. (Ex. 2, p. 2).

47. The impetus behind the Company's requested contract term proposal is the fact that system-wide QF contracts have become a major factor in customer rates. (Tr. Vol. I, p. 101, ll. 14-18). Wyoming's allocated share of the projected costs of executed QF contracts over the next ten years is \$460 Million. (Tr. Vol. I, p. 101, ll. 14-18). Throughout the hearing this was generally referred to as the "magnitude issue," *i.e.* the idea that the sheer number of the potential QF contracts and their associated MW volumes system-wide creates an exponential fixed price risk to ratepayers. The Company proposes to alleviate this risk with its request to reduce the maximum QF contract term to three years, which constitutes an 85% reduction in the duration of the term. (Tr. Vol. I, pp. 107, 122, 125, 130, 152, 153, 199, 205, 329, 331, 378, 449 and 491).

48. RMP further asserted that 20-year QF PPA terms are inconsistent with its resource acquisition policies and practices and are not aligned with its IRP and planning cycle.[5] The Company states it does not enter into long-term transactions, with fixed price risks, unless there is a long-term resource need identified in the IRP. The Company testified such a long-term resource is not needed until 2028. (Tr. Vol. I, p. 100, ll. 12-15).

[5] QF PPA's are not evaluated in the IRP process nor included as resource options that could be selected. (Tr. Vol. I, p. 186, ll. 7-21).

49. In 2014, Wyoming's RMP average retail load was 1,166 MW and its minimum retail load was 963 MW. RMP currently has 403 MW of "nameplate capacity" from existing Wyoming QF PPA contracts. (Ex. 1, p. 7). Solar and wind generation projects are considered intermittent, rather than continuously available, resources. Accordingly, they generally have lower expected actual outputs or "capacity/load factors" than their nameplate capacities.[6] RMP witness Paul Clements testified that wind projects have an average capacity factor of 39%. (Tr. Vol. I, p. 172, ll. 5-9). This intermittency effect can cause potential inefficient variability in the grid's capacity to service the Company's load, which is acknowledged in the avoided cost pricing and inclusion of integration costs. (*Id.* and Tr. Vol. II, pp. 288-290 and 310-316).

50. In Application Exhibit 2, RMP provides detailed information on its current system-wide QF pricing queue including each QF project's state location, nameplate capacity, type (solar, wind, or hydro), and expected online in-service date. (Exs. 2, p. 11, ll. 17 and 2.1). There are 94 total RMP system-wide proposed QF projects, with an aggregate potential nameplate capacity of 4,632 MW. (Ex. 2.1). There is significant expansion of system-wide QF activity arising from numerous solar projects located primarily in Utah, Oregon, and Idaho. (*Id.* and Ex. 297). However, the QF penetration rate has remained around 6% of energy provided on a system-wide basis. (Tr. Vol. II, p. 330, l. 15).

51. More critically, only nine of the proposed QF projects are located in Wyoming. (Ex. 2.1, p. 2). Eight are wind projects and one is a solar project, which together comprise a total *nameplate capacity* of 713 megawatts (MW). (*Id.*). Thus, Wyoming QF projects make up only approximately 6.5% of the total expected QF growth system-wide. (*Id.*).

52. Historically, RMP's data indicates that system-wide there is only a 10% project completion rate of the total QF portfolio in its pricing queue. (Ex. 200, p. 12). Further, only 75% of those projects with executed PPAs in the queue reach commercial operation making them eligible to receive avoided cost pricing. (Exs. 200, p. 13; 200.1; 200.2 and 200.3). This data weakens the Company's argument of significant fixed-price risk to Wyoming ratepayers arising from the potential QF project queue. (*Id. and.* Ex. 200, p. 16, ll. 22-29). Additionally, the data demonstrates that any fixed-price risk does not generally concern Wyoming QFs governed by Schedule 37.

53. RMP Exhibit 16 is a redacted indicative pricing proposal given to a Wyoming QF developer on March 21, 2016. It includes illustrative avoided cost prices (20-year nominal leveled prices at a 6.6% discount rate) with and without the Gateway Transmission Project.[7] The rates

[6] "Nameplate capacity" refers to the normal maximum output of a generating source under specific conditions designated by the manufacturer often on a nameplate affixed to the machinery. This is the most common number used and is typically expressed in megawatts (MW). "Capacity or load factor" is the average expected output of a generating source over a specified period of time, typically over an annual period. It is a ratio usually expressed as a percentage of the nameplate capacity or in decimal form (e.g. 30% or 0.30). *See generally,* U.S. Energy Information Administration glossary, http://www.eia.gov/tools/glossary/.

[7] The Gateway Transmission Project is jointly proposed by RMP and Idaho Power to build and operate approximately 1,000 miles of new high-voltage transmission lines between the Windstar Substation near Glenrock, Wyoming and the Hemingway Substation near Melba, Idaho. The project would include approximately 150 miles of 230 kilovolt (kV) lines in Wyoming and approximately 850 miles of 500 kV lines in Wyoming and Idaho. According to the Companies, the project is meant to help supply energy to customers and improve the reliability of the electric system

are respectively $27.76 and $26.65/MWh with and without Gateway. (*Id.* pp. 4-5). These rates compare favorably to those found in RMCRE Exhibit 621, an excerpt from RMP's 2015 IRP, which indicates the total resource cost for a Company built 2 MW wind turbine in Wyoming is $36.85/MWh. (Ex. 621, p. 99).

54. RMP's Clements testified it would be fair to allow the seven Wyoming wind projects in the final contracting and execution stage to proceed with the existing 20-year term contracts if its application were otherwise approved. (Tr. Vol. I, p. 209). This militates against the recognition of a significant existing fixed price risk for ratepayers. It all but eliminates Wyoming's share of projects in the remaining queue. We note that projects located in other states are not subject to Wyoming PURPA policies.

Potential Effect of a Three-Year PPA Term on Wyoming QF Projects

55. Multiple Intervenor witnesses testified that a three-year maximum term for QF PPAs would impair the ability of QFs to achieve project financing and capital, and ultimately would discourage QF development in Wyoming in contravention of PURPA. OCA notes PURPA provisions provide QFs should have a reasonable opportunity to sell the power they generate to the RMP at a fair price. OCA further explains it believes a "reasonable opportunity" to sell power is indirectly dependent on a QF being able to secure financing to develop a project which is directly related to contract length. (Ex. 200, p. 8).

56. RMP's position is that the ability to obtain financing is not a requirement that the Commission should consider. The Company argues that it is not stated in PURPA or in the rules implementing PURPA. (Tr. Vol. I, p. 139, ll. 12-18). However, RMP's Clements acknowledged its proposal of a three year contract term will make it more difficult for QFs to obtain financing "under the historic financing model for QFs." (Tr. Vol. I, p. 179, l. 21- p. 180, l. 4).

57. REC witness John Lowe was previously employed by PacifiCorp for 31 years, 25 of which included direct involvement with implementation of PURPA. He is now employed representing QFs in the Company's service territory, primarily small hydro QFs such as those in the REC coalition. (Ex. 700, p. 1 and Tr. Vol. I, p. 224). He testified that short term QF PPA contracts, like those with three-year terms, are not conducive to projects being developed or revitalized and that 20 year terms are "a good number." He acknowledged a lesser number may be good as well, but "three is probably not it." (Tr. Vol. I, p. 226, ll. 9-19).

58. Michael Speerschneider, Chief Permitting and Public Policy Officer for EverPower Wind Holdings testified that limiting the maximum term of a QF PPA to three years would adversely affect the abilities of the renewable energy developers to finance QF projects. (Ex. 601 and Tr. Vol. II, p. 375). He explained that in his experience there are three primary reasons that commercial banker QF investors will not finance on short-term PPAs. First, because the project finance industry expects to be paid over the course of the loan, and a three-year PPA would require extremely high dollars per megawatt for coverage repayment of their debt. (Tr. Vol. II, p. 381, ll. 16-24). Second, the banks are not comfortable taking "recontracting" or residual risk so that there is little value beyond the end of the PPA, which is why the term of the PPA is so important to the

by enabling delivery of electricity from existing and new generating resources, including renewable resources such as wind. http://www.gatewaywestproject.com/project_info.aspx debt sizing and lending decision. (Tr. Vol. II, p. 381, l. 25- p. 382, l. 6). Third, commercial banks do not believe that short term PPAs provide the project developer with enough return to stay fully invested in the project, and thus are more of a risk for the lender. (Ex. 601, pp. 2-3, ll. 44-50 and Tr. Vol. II, p. 382, ll. 7-11).

59. Michael Speerschneider further testified that a 20-year term that re-opened or adjusted the price every three years would be viewed similarly to a three-year term PPA by investors and lenders. (Tr. Vol. II, p. 382, l. 22- p. 383, l. 8). He responded to NLRA witness Laura Ladd's testimony by explaining that some of the alternative financing arrangements she suggested are available and can be used by QF developers to create further value and reduce the cost of their capital, and thus their cost of power, but they are only available once the initial financing mechanism driven by the long-term PPA term is in place. (Tr. Vol. II, p. 383, ll. 9- p. 385, l. 9).

60. RMCRE witness Hans Isern is employed as a Senior V.P. of Origination for sPower, which is a developer, financier, owner and operator of renewable generation projects. (Ex. 602, ll. 6-12). He testified that the 20-year PPA term is the industry standard, and that reducing that term to three years would be a huge blow to the IPP industry and its ability to provide competitive power options. (*Id.*, pp. 397-398). This result is caused by the fact that the QF developer's cost of power is driven by its multiple sources of capital, such as equity, debt, and tax equity. (*Id.*, p. 398, ll. 12-16). In his experience, shorter term PPAs are driven by other factors such as extra state tax credits or other additional revenue streams. He further testified that ratepayers benefit from this competition because it drives the avoided cost rate into the $30/MWh range. (*Id.*, p. 399, ll. 9-13). Lastly, he testified that if the PPA contract term is shortened to three years, it is not possible for the developers to simply shift additional risk costs to the banks or investors because they require longer term revenue certainty to repay their capital costs. (*Id.*, p. 400, ll. 15-20). As the banks and investors lend on a national and international basis it is unlikely that they will create a Wyoming exception for their lending model. (*Id.*, p. 400, l. 21- p. 401, l. 2). Instead, the QF development will simply take place where projects can receive adequate financing. (Tr. Vol. II, p. 400, ll. 15-20).

61. The experiences of Idaho and Washington show a chilling effect on QF development after those states approved the use of short-term PPA contracts. Between 1996 and 2001, the Idaho Commission reduced its maximum PPA contract term to five years. (Ex. 705 and Tr. Vol. I, p. 142, ll. 22-23). During that time frame, only a single project was developed for Idaho Power. (Tr. Vol. I, p. 143, ll. 1-5). During the same time period, Clements could not recall any developments in Idaho for RMP other than small hydro until the term was increased back to 20 years. (Tr. Vol. I, p. 142, l. 6- p. 143, l. 11). Paul Clements described it as "shutting the barn door after the horses escaped." (Tr. Vol. I, p. 121, ll. 17-30). Likewise, Washington's approved maximum fixed-price contract is five years. PacifiCorp has three QF PPAs that operate in Washington, and only one is subject to a 5 year PPA term. (Tr. Vol. I, p. 140, l. 21- p. 141, l. 1).

Modification of Avoided Cost Methodology

62. In its Application, RMP requests to modify its avoided cost PDDRR methodology calculation to include "indicative pricing" for QF contracts to reflect all QFs in the system-wide queue. (Ex. 1, pp. 1 and 38 and Ex. 3, p. 10, ll. 19-23). Indicative prices are preliminary estimates of avoided cost rates, which serve as the starting point for negotiations between QFs and a utility. They may differ from contract prices. The current RMP PDDRR methodology recognizes only

executed QF contracts in the calculation of the avoided cost. All other *proposed* (queued) QFs are excluded in the calculation.

The Current PDDRR Method

63. RMP prepares two simulations using the Generation and Regulation Initiative Decision Tool (GRID) model to determine the avoided costs under the PDDRR method. The first GRID model run is the "Base Simulation," which calculates the Net Power Cost (NPC) of the current portfolio, including resources identified in the most recent Integrated Resource Plan. The second GRID model run is the "Avoided Cost Simulation," which calculates NPC for the portfolio with two modifications: the operating characteristics of the proposed QF are added with its energy included at zero cost and capacity and other operational characteristics of the next preferable resource are reduced by an amount equal to the QF capacity contribution. This is known as "partial displacement" and reflects the deferral of a portion of the next avoidable resource in a manner that maintains resource adequacy and system reliability at a level equivalent to the Base Simulation. (Ex. 137).

64. "Front Office Transactions," (FOT) are generally the model's next deferrable resource until the date of the first new thermal unit identified in the IRP. Thus, "Avoided Costs" are equal to the difference in the NPC between the Avoided Cost Simulation and the Base Simulation, plus the fixed costs associated with the partial displacement of the next preferable resource from the IRP. The deferred fixed costs are calculated on a cost per kilowatt-year basis using the resource operating characteristics and payment factor from the IRP. The resource payment factor from the IRP is used to convert the proxy plant capital cost to a real levelized dollar per kilowatt-year that is grossed up for the effect on the revenue requirement. Inflation is then applied to convert the first year fixed cost to a nominal payment stream and the value is adjusted for the capacity contribution of the QF in question. (Ex. 137).

65. The GRID model runs and PDDRR methodology are based on market prices in the Company's most recent official forward price curve and the loads in the Company's most recent load forecast. RMP's GRID model determines the least cost resources to serve retail load and support economical wholesale sales transaction in each hour. These resources will be either generation from the least expensive unused units, wholesale purchases, or reductions in wholesale sales. The least cost resources are dependent on the load and transmission availability, as well as the price and volume available from each generation and market resource. The PDDRR methodology compares the GRID model results from the two scenarios mentioned in paragraph 64. The "Base Simulation" reflects the resource stack in the Company's current forecast. The "Avoided Cost Simulation" reflects the resource stack with partial displacement of the IRP resources and the addition of the QF. When load increases, increasingly more expensive resources will be dispatched, but when load decreases, less expensive resources will be dispatched. When power prices increase, the Company's fuel costs for natural gas generally also increase and wholesale purchases get more expensive (these can be offset by larger benefits from wholesale sales). (Ex. 138).

66. The GRID model automatically accounts for the effects of changing loads and market prices in determining the optimal resource dispatch and thus a QF's avoided cost. (Ex. 137). The GRID model also recognizes the attributes of individual QF projects such as size,

generation profile and location, as well as the Company's ability to integrate the QF output into its system subject to transmission constraints. (Ex. 3, p. 3).

67. The current PDDRR methodology used by the Company recognizes only *executed* QF contracts in the calculation of the avoided cost. All other *proposed* (queued) QFs are not included in the calculation process.

RMP Requested Modification to PDDRR

68. The Company requests to incorporate the system-wide *proposed* QF projects into the calculation of the avoided cost for Wyoming QFs, arguing it will more accurately reflect the avoided cost of the displaced resources. RMP states that if the system-wide queued QFs are ignored in this calculation process, the PDDRR calculation will result in payments to QFs that exceed the avoided cost. (Exs. 1 and 3).

69. RMP requests the Commission approve its modification and indicative pricing proposal on two grounds:

A. First, it contends FERC has determined that a "legally enforceable obligation" (LEO) may include arrangements short of an executed contract between an electric utility and the QF, and that a state may not require a QF to obtain a fully executed contract before recognizing imposition of a LEO and locking in avoid costs rates. The Company reasons that since a QF can establish a right to sell to a utility before a contract is signed, *proposed* QFs should likewise be reflected in avoided costs.

B. Second, it states there has been a significant increase in the number of QF requests received by RMP across its system. (Ex. 3, p. 8).

Legally Enforceable Obligation

70. FERC's PURPA rules and regulations include a requirement that a QF has the option to sell power, not only as available, but pursuant to a "legally enforceable obligation" (LEO) over a specified term. 18 C.F.R. § 292.304(d)(2). FERC has explained that use of the phrase "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible facility merely by refusing to enter into a contract with a QF. *See* Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880 (noting "the need for qualifying facilities to be able to enter into contractual commitments" and agreeing to "the need for certainty with regard to return on investment in new technologies").

71. The Commission has primary responsibility to determine what constitutes a LEO under PURPA and the Wyoming Schedule 38 procedures. 16 U.S.C. § 824a-3(f). The indicative pricing provided by RMP clearly states that an enforceable obligation is not created at the stated indicative pricing. (Ex. 16). Further, nothing in the FERC's avoided cost pricing regulations "requires any electric utility to pay more than the avoided costs for purchases." 18 C.F.R. § 292.304(a)(2).

72. In addition, as discussed by RMP witness Dickman, the FERC/Idaho cases that initiated RMP's concerns were from the Idaho Commission's decision to change the size of

facilities that qualified for published rates under a standard offer, and to make the decision retroactive. (Tr. Vol. II, p. 269- p. 270, l. 10 and Ex. 620 *Cedar Creek Wind, LLC,* 137 FERC ¶ 61,006 (FERC 2011)). In doing so, the Idaho Commission established a bright line test that there would be no LEO to receive the existing rates if the QF developer did not have either an executed PPA or had filed a complaint at the Commission by the deadline. (Tr. Vol. II, p. 275, ll. 6-14). The FERC petitioners were QF developers in negotiations with RMP who had executed the PPA by the deadline and returned it to RMP and RMP (as characterized by FERC) had "refused to sign the PPA." Under these narrow circumstances FERC determined a bright line test was inconsistent with PURPA regulations and a LEO could have arisen. (Ex. 620, pp. RMCRE000718-000719, ¶¶ 30, 32, 36 and 41) These circumstances have no parallel in Wyoming. (Tr. Vol. II, p. 268, l. 16- p. 284, l. 12 and Ex. 620 *Cedar Creek Wind, LLC,* 137 FERC ¶ 61,006 (FERC 2011)).

73. RMP concedes that no QF developer in Wyoming has asserted a LEO or requested a price lock prior to executing a PPA. (Ex. 318 and Tr. Vol. II, pp. 289, l. 19-290, l. 4). RMP acknowledged that if a QF developer asserted a LEO prior to PPA execution, the Company could (under the existing terms of Schedule 38) refresh the price up until the time the PPA was executed. (*Id.*).

Effect of Proposed PDDRR modification in Wyoming

74. The concerns regarding RMP's proposed PDDRR methodology modification universally expressed by Intervenors WIEC, REC, RMCRE, and CPEM are that RMP's proposal suppresses indicative prices by including projects in the pricing queue which may never complete the contracting process. There is no systematic subsequent adjustment to remove those MWs when projects drop out of the queue. The existing indicative pricing ensures that as new QF projects sign PPAs, the PDDRR method updates QF pricing so that the PPA MWs are incorporated into the avoided cost calculation. (Tr. Vol. II, p. 328, l. 3- p. 329, l. 7; 368, ll. 7-17 and Ex. 600, pp. 20-22).

75. RMP calculated the impact on the PDDRR method avoided costs by including roughly 4,100 MW of proposed QFs (located in Wyoming, Idaho, Utah, and Oregon) prior to the next Wyoming QF, and determined that including these projects, rather than just those with an executed PPA, would reduce the QF's indicative pricing by 11% compared to the existing method. (Ex. 3, p. 9, l. 20- p. 10, l. 5).

76. As addressed in paragraph 52 above, RMP's data indicates that historically system-wide there is only a 10% completion rate as a percentage of the total portfolio of QFs in the pricing queue.

77. Further, while RMP and its parent PacifiCorp may have experienced a system-wide increase in QF development projects seeking avoided cost pricing, as discussed above in paragraph 51 that increase has largely taken place outside of Wyoming.

<u>Initiation of an Avoided Cost Methodology Collaborative</u>

78. As the hearing progressed, it became apparent that the Company has implemented a revised QF process in Utah and Idaho that is no longer consistent with the QF process in Wyoming. (Tr. Vol. II, pp. 494-500). In recognition of the complex problems posed by adjustment

of the Schedule 38 QF process, OCA's Dr. Kolb at length concluded that a collaborative study process in a separate docket would be required. (Tr. Vol. II, p. 483). RMP's Clements said the company would be "okay with that." We find that such a process would allow for better judgments about the best overall result. It would also allow the Company to propose a solution that could be harmonized with the QF procedures in other states, as opposed the proposals in this docket, which would at best be a partial response to changes already made elsewhere in RMP's system.

79. These issues raised in this docket – the PDDRR methodology, QF pricing queue procedures, and PPA terms and length - should be further explored in light of Wyoming's changing load environment coupled with any system-wide effect caused by the rapid development of solar and wind QFs in other states in the PacifiCorp system. System-wide penetration and integration of QFs and their operational effects on the Company's existing Wyoming generation resources should be reported regularly to the Commission and any renewable integration studies completed by the Company or on its behalf should be provided to the Commission. (Tr. Vol. II, pp. 306-315).

Principles of Law

80. Wyo. Stat. § 37-3-101 requires that:

> All rates shall be just and reasonable, and all unjust and unreasonable rates are prohibited. A rate shall not be considered unjust or unreasonable on the basis that it is innovative in form or in substance, that it takes into consideration competitive marketplace elements or that it provides for incentives to a public utility. * * * The commission may determine that rates for the same service may vary depending on cost, the competitive marketplace, the need for universally available and affordable service, the need for contribution to the joint and common costs of the public utility, volume and other discounts, and other reasonable business practices.

81. Wyo. Stat. § 37-3-106(b) and (c) allow the Commission to suspend rates for a total of ten months:

> (b) Unless the commission otherwise orders, no public utility shall make any change in any rate which has been duly established except after thirty (30) days notice to the commission, which notice shall plainly state the changes proposed to be made in the rates then in force, and the time when the changed rates will go into effect. . . .
>
> (c) Whenever there is filed with the commission by any public utility any application or tariff proposing a new rate or rates, the commission may, either upon complaint or upon its own initiative, initiate an investigation, hearing, or both, concerning the lawfulness of such rate or rates. Pending its decision thereon, the commission may suspend such rate or rates, before they become effective but not for a longer initial period than six (6) months beyond the time when such rate or rates would otherwise go into effect. If the commission shall thereafter find that a longer time will be required, the commission may extend the period of suspension for an additional period or periods not exceeding in the aggregate, three (3) months.

82. The Commission has broad powers to inquire into the facts surrounding the determination of rates. They include Wyo. Stat. § 37-2-119, which states that:

> In conducting any investigation pursuant to the provisions of this act the commission may investigate, consider and determine such matters as the cost or value, or both, of the property and business of any public utility, used and useful for the convenience of the public, and all matters affecting or influencing such cost or value, the operating statistics for any public utility both as to revenues and expenses and as to the physical features of operation in such detail as the commission may deem advisable; the earnings, investment and expenditures of any such corporation as a whole within this state, and as to rates in plants of any water, electric, or gas corporations, the geographical location thereof shall be considered as well as the population of the municipality in which such plant is located.

83. Wyo. Stat. § 37-2-120 prohibits the Commission from making any order "which requires the change of any rate or service. . . unless or until all parties are afforded an opportunity for a hearing in accordance with the Wyoming Administrative Procedure Act." The Act establishes general procedures for Commission cases, including the giving of reasonable notice. Wyo. Stat. § 16-3-107; in accord are Wyo. Stat. §§ 37-2-201, 37-2-202, and 37-3-106. *See also*, Sections 106 and 115 of the Commission's Rules.

84. Wyo. Stat. § 37-2-121 gives the Commission latitude to determine the actual rates to be charged by a utility and allows public utilities to present innovative regulatory forms, policies, and rate making methods, stating that:

> If upon hearing and investigation, any rate shall be found by the commission to be inadequate or unremunerative, or to be unjust, or unreasonable, or unjustly discriminatory, or unduly preferential or otherwise in any respect in violation of any provision of this act, the commission . . . may fix and order substituted therefor a rate as it shall determine to be just and reasonable and in compliance with the provisions of this act. The rate so ascertained, determined and fixed by the commission shall be charged, enforced, collected and observed by the public utility for the period of time fixed by the commission. The rates may contain provisions for incentives for improvement of the public utility's performance or efficiency, lowering of operating costs, control of expenses or improvement and upgrading or modernization of its services or facilities. Any public utility may apply to the commission for its consent to use innovative, incentive or nontraditional rate making methods. In conducting any investigation and holding any hearing in response thereto, the commission may consider and approve proposals which include any rate, service regulation, rate setting concept, economic development rate, service concept, nondiscriminatory revenue sharing or profit-sharing form of regulation and policy, including policies for the encouragement of the development of public utility infrastructure, services, facilities or plant within the state, which can be shown by substantial evidence to support and be consistent with the public interest.

85. The public interest must come first in Commission decisions; and, as the Wyoming Supreme Court has stated, the desires of the utility are secondary to it. *Mountain Fuel Supply Company* v. *Public Service Comm'n,* 662 P.2d 878 (Wyo. 1983). Construing Wyo. Stat. § 37-3-101, which requires rates to be reasonable, the Court in *Mountain Fuel, supra,* at 883, commented that:

> This court cannot usurp the legislative functions delegated to the PSC in setting appropriate rates, but will defer to the agency discretion so long as the results are fair, reasonable, uniform and not unduly discriminatory.

Later, 662 P.2d at 885, the Court in *Mountain Fuel* observed that:

> We agree that if the end result complies with the 'just and reasonable' standard announced in the statute, the methodology used by the PSC is not a concern of this court, but is a matter encompassed within the prerogatives of the PSC.

In accord are *Great Western Sugar Co.* v. *Wyo. Public Service Comm'n and MDU, 624* P.2d 1184 (Wyo. 1981); and *Union Tel Co.* v. *Public Service Comm'n,* 821 P.2d 550 (Wyo. 1991), wherein the Supreme Court stated, 821 P.2d at 563, that it ". . . has recognized that discretion is vested in the PSC in establishing rate-making methodology so long as the result reached is reasonable." Read *in pari materia,* these statutes articulate the basic mechanism of the public interest standard which the Commission is to follow in its decisions.

86. In *Willadsen v. Christopulos*, 1987 WY 5, 731 P.2d 1181, (Wyo. 1987), the Wyoming Supreme Court discussed the standard of proof to be used in Wyoming administrative hearings. Construing Wyoming Statutes (W.S. §§ 41-3-911(b) and 41-3-911(c)), neither of which establishes a standard to be applied in matters coming before the State Board of Control, the Supreme Court stated, 1987 WY 5 at ¶13, with regard to W.S. § 41-3-911(c):

> Under that statutory section and the applicable provisions of the Wyoming Administrative Procedure Act, the standard applicable to an adjudicatory hearing before the Board of Control, unless otherwise stated, is the "preponderance of the evidence" standard customarily used in civil cases. *Amerada Hess Pipeline Corporation v. Alaska Public Utilities Commission, Alaska*, 711 P.2d 1170, 1179 n. 14 (1986); *Intermountain Health Care, Inc. v. Board of County Commissioners of Blaine County, Idaho*, 107 Idaho 248, 688 P.2d 260, 263 (1984), quoting E. Cleary, McCormick on Evidence § 357 (3d ed. 1984).

Later, the Court emphasized the necessity of applying this standard, 1987 WY 5 at ¶14, saying:

> Because the Board of Control failed to apply the preponderance of the evidence standard and instead applied the substantial evidence test applicable to appellate review of an agency decision, we find that petitioners were denied due process.

87. In the Commission's 2011 *Order* in Sub 388, it distinguished the case from *Willadsen* noting that "one of the applicable statutes on which we rely in this case, W.S. § 37-1-121, specifies the substantial evidence standard in certain situations. These are:

> . . . [P]roposals which include any rate, service regulation, rate setting concept, economic development rate, service concept, nondiscriminatory revenue sharing or profit-sharing form of regulation and policy, including policies for the encouragement of the development of public utility infrastructure, services, facilities or plant within the state, which can be shown by substantial evidence to support and be consistent with the public interest.

Accordingly, the Commission held "given the mixture of issues in this case, we must therefore agree the higher preponderance of the evidence standard should apply." *2011 Order* ¶ 52.

88. Section 317 of the Commission's Rules sets forth the regulations regarding arrangements between electric utilities and qualifying cogeneration and small power production facilities pursuant to implementation of sections 201 and 210 of PURPA.

Conclusions of Law

89. RMP is duly authorized by the Commission to provide retail electric public utility service in its Wyoming service territory under certificates of public convenience and necessity as issued and amended by the Commission. RMP is an electric public utility as defined in Wyo. Stat. § 37-1-101(a)(vi)(C), subject to the Commission's general and exclusive jurisdiction to regulate it as a public utility in Wyoming pursuant to Wyo. Stat. § 37-2-112.

90. Proper public notice of these proceedings was given in accordance with the WAPA, Wyo. Stat. § 37-2-203 and Section 106 of the Commission's Rules. The public hearings were held and conducted pursuant to Wyo. Stat. §§ 16-3-107, 16-3-108, 37-2-203, and applicable sections of the Commission's Rules. The interventions of the Parties were properly granted, and the entities that intervened became parties to the case for all purposes.

91. In 1978, Congress enacted PURPA in response to a national energy crisis and directed FERC to adopt rules and regulations to implement it. PURPA's goals are to promote energy conservation, encourage the development of cogeneration and small power production facilities, reduce domestic demand for traditional fossil fuels, *Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 404 (1983), and lessen the country's dependence on foreign oil. *FERC v. Mississippi*, 456 U.S. 742, 745-46 (1982). Under the Act, FERC prescribes rules and regulations for implementation, 16 U.S.C. § 824a-3(a),(b) and state regulatory authorities implement FERC's rules. However, states have "discretion in determining the manner in which the rules will be implemented."[8] *FERC v. Mississippi*, 456 U.S. at 751 (1982). Section 317 of the Commission's Rules implements PURPA in Wyoming.

[8] The U.S. Supreme Court held in *F.E.R.C. v. Mississippi*, that the challenged PURPA provisions do not impinge state sovereignty in violation of the Tenth Amendment. It determined insofar as § 210 authorizes the FERC to exempt qualified power facilities from state laws and regulations, it does nothing more than preempt conflicting state enactments in the traditional way. *Id.* at 758-771. With respect to § 210's requirement that state authorities implement FERC's rules, the statute and its implementing regulations simply require state commissions to settle disputes arising under the statute, the very type of adjudicatory activity customarily engaged in by the Mississippi Public Service Commission. *Id.* at 759-761. The "mandatory consideration" provisions of Titles I and III do not involve the compelled exercise of Mississippi's sovereign powers or set a mandatory agenda to be considered in all events by state legislative or administrative decisionmakers, but simply establish requirements for continued state activity in an otherwise preemptible field. *Id.* at 761-770. Similarly, the procedural requirements of Titles I and III do not compel the exercise of a State's sovereign power. If Congress may require a state administrative body to consider proposed federal regulations as a condition to its continued involvement in a preemptible field, it may require the use of certain procedural minima during that body's deliberations on the subject. "The procedural requirements obviously do not compel the exercise of the State's sovereign powers, and do not purport to set standards to be followed in all areas of the state commission's endeavors." *Id.* at 770-771.

92. PURPA requires utilities to purchase energy from generating facilities known as qualifying facilities or QFs. QFs are facilities that have a power production capacity no greater than 80 megawatts, which are owned by persons not primarily engaged in the generation or sale of electricity other than electric power from small production facilities. Rule 317(b)(i).

93. Because the rates utilities pay QFs impact consumers, the rates must be just and reasonable to consumers and in the public interest, but must not discriminate against QFs. 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304; *Am. Paper Inst*., 461 U.S. at 404-05; Commission Rule § 317(i)(i). Pursuant to FERC Rules, QF rates are set at a utility's "full avoided cost." Full avoided cost is "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." 18 C.F.R. § 292.10 1 (b)(6). In other words, a utility must purchase energy and capacity from QFs at the same price it would have to pay if it otherwise purchased or generated the energy or capacity on its own. This requirement is commonly termed the "ratepayer indifference standard." It means ratepayers should be economically indifferent to the source of the utility's energy by ensuring the cost to the utility purchasing from a QF does not exceed the cost it would incur if it were purchasing from another source. Pursuant to Commission Rule §§ 317(i) and (j), the Commission is responsible for determining a utility's avoided cost and setting appropriate QF rates.

94. Generally, it appears that Federal and State law are silent on the issue of the duration of the PURPA QF Contract Term. No statute or rule prescribes a minimum term for QF PPAs. Federal PURPA regulations require QFs have the option to sell electricity "over a specified term" for a price established at the time of contracting, but the regulations are silent as to how long the "specified term" must be. *See* 18 C.F.R. § 292.304(d).

95. The Commission has the authority to modify the maximum term of only those PPA contracts for QF projects located in Wyoming. In the absence of specific legal guidance from the Wyoming Legislature, Congress or FERC,[9] it falls to the Commission to exercise its discretion to establish a PURPA QF contract term that advances the policy interests and goals underlying PURPA of encouraging development, while not discriminating against QFs in Wyoming, and without unduly burdening Wyoming ratepayers with excessive price risk. As FERC has noted:

> States are allowed a wide degree of latitude in establishing an implementation plan for section 210 of PURPA, as long as such plans are consistent with our regulations. Similarly, with regard to review and enforcement of avoided cost determinations under such implementation plans, we have said that our role is generally limited to ensuring that the plans are consistent with section 210 of PURPA…." In this regard, the determinations that a state commission makes to implement the rate provisions of section 210 of PURPA are by their nature fact-specific and include consideration of many factors, and we are reluctant to second guess the state commission's determinations; our regulations thus provide state commissions with guidelines on

[9] FERC has interpreted the phrase "long-term" in regard to a different section of PURPA. FERC Order 688-A included an interpretation of the language in 16 USCA § 824a-3(m) also known as 210(m) that created a must buy exception for those QFs with access to competitive wholesale markets. FERC held that contracts of a year or more are sufficiently long-term to meet the statutory requirement that there be "wholesale markets for long-term sales of capacity and energy" ***within the meaning of section 210(m)(1)(A)(ii)*** (emphasis added).

factors to be taken into account, "to the extent practicable," in determining a utility's avoided cost of acquiring the next unit of generation.[10]

96. The Commission concludes that RMP has not met its burden to show that the solutions proposed in its application: [1] a substantial 85% reduction in the maximum term of its Wyoming PPA contract; coupled with [2] a modification of the Wyoming PDDRR methodology to include all system-wide QFs in the indicative pricing queue will reasonably address the system-wide problems it alleges give rise to the application. The recent surge in QF applications is primarily occurring in other states in the PacifiCorp system. Adopting RMP's proposal also risks discouraging QF development in Wyoming in contravention of PURPA, without any likely effect on whatever factors may be causing increased QF proposals in those other states.

97. If some progress is to be made on this problem, it is more likely that it will result from pursuing changes to PURPA-related tariffs in a manner which has already been accomplished in Utah, through negotiation. RMP has represented to us that these changes are inconsistent with the current structure of the Wyoming tariff, both in process, and in the minimum contract term, which is 15 years in Utah. We find and conclude that a collaborative effort would provide an opportunity to harmonize Company policy on a multi-state basis, as well as an opportunity to address all of the issues raised in this case in a practical and detailed manner.

98. In view of our conclusion that a collaborative is the appropriate way forward, we do not need to address the problem of the imposition of a "legally enforceable obligation" prior to an executed contract, nor do we need to address any modifications to the details of the PDDRR methodology.

99. Pending the outcome of the collaborative, there is no present public interest in overturning the Commission's previous determinations regarding the duration of the PPA contract term or PDDRR methodology.

NOW THEREFORE, IT IS ORDERED:

1. Pursuant to the Commission's deliberations held on April 22, 2016, Rocky Mountain Power's Application is hereby denied. The Company is directed to initiate a collaborative process with relevant stakeholders to address substantive and procedural reforms to Wyoming's PPA and avoided cost methodology.

2. Rocky Mountain Power is hereby directed to update Exhibit 2.1, a list of all the QFs in its system-wide queue, on a semi-annual basis as a compliance filing in this Docket. The Company is further directed to provide the Commission with semi-annual updates on the status of system-wide penetration and integration of QFs and their operational effects on the Company's existing Wyoming generation resources, and to provide any renewable integration studies completed by the Company or on its behalf.

3. This *Order* is effective immediately.

[10] *Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059 at P 24 (2010).

MADE and ENTERED at Cheyenne, Wyoming, on June 23, 2016.

PUBLIC SERVICE COMMISSION OF WYOMING

ALAN B. MINIER, Chairman

WILLIAM F. RUSSELL, Deputy Chairman

(SEAL)

PUBLIC SERVICE COMMISSION OFFICIAL SEAL OF WYOMING

Attest:

LORI L. BRAND, Assistant Secretary

Public Service Commission of Montana

Docket No. D2014.4.43, Testimony of Greenfield Wind, LLC

Jul. 28, 2014

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DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF the Petition of NorthWestern Energy to Set Terms and Conditions of Contract Between NorthWestern Energy and Greenfield Wind, LLC	)))))	REGULATORY DIVISION DOCKET NO. D2014.4.43

**INTERVENOR TESTIMONY
OF
GREENFIELD WIND, LLC**

Greenfield Wind, LLC ("Greenfield"), by and through counsel of record, submits the following testimony in support of its positions in this matter:

- Testimony of Martin H. Wilde and exhibits (attached as **Exhibit A**)
- Testimony of Don C. Reading and exhibit (attached as **Exhibit B**)

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RESERVATION OF RIGHT TO SUPPLEMENT TESTIMONY

Greenfield reserves the right to supplement its testimony to properly account for newly received information from NorthWestern. Several of NorthWestern's Responses to Greenfield's Data Requests were served well after the July 3, 2014 Response Deadline. In particular, critical information regarding NorthWestern's *differential revenue requirement model* – which is at the heart of this dispute - was not received by Greenfield until July 22, 2014. Moreover, information contained in the July 22, 2014 Responses can only be properly understood if Greenfield is able to serve additional, follow-up data requests on NorthWestern. Thus, in order for Greenfield to be able to submit complete Intervenor Testimony, which is based on a complete understanding of the pertinent and relevant facts, it reserves the right to supplement its Testimony based on newly discovered information from NorthWestern.

RESPECTFULLY SUBMITTED ON THIS 25^{TH} DAY OF JULY, 2014

MEYER, SHAFFER, & STEPANS, PLLP

Ryan Shaffer

CERTIFICATE OF SERVICE

The undersigned hereby certifies that on the 25th day of July, 2014, a true and accurate copy of the foregoing document was served by U.S. Mail upon the following parties:

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Exhibit A

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.4.43
Greenfield Wind, LLC Petition
NorthWestern Energy

PREFILED DIRECT TESTIMONY OF

MARTIN H. WILDE

ON BEHALF OF GREENFIELD WIND, LLC

TABLE OF CONTENTS

I. Witness Information

Q. Please state your name and business address.

A. Martin H. Wilde, 1943 U.S. Highway 1943, Fairfield, Montana 59436.

Q. By whom are you employed and in what capacity?

A. I am CEO and Principal Engineer of WINData LLC and managing member of Greenfield Wind, LLC and Greenfield Wind II, LLC.

Greenfield Wind, LLC and Greenfield Wind II, LLC are locally owned entities, and upstream owners are also Montana residents.

Q. On whose behalf are you testifying?

A. On behalf of the Greenfield Wind entities.

Q. Please summarize your education and relevant employment history.

A. I am currently Principal Engineer and CEO of WINData LLC, a veteran energy business development company with 21 years' experience in Montana and the west. I am a researcher, project engineer and business development specialist. I possess a Master of Science degree in Engineering from Ohio State University. My experience comprises engineering and business development in wind energy in Montana dating back to 1991.

I began my work in Montana wind energy in the early 1990s, initiating development work on the Blackfeet Reservation and Cut Bank and later in Judith Gap and Big Timber. My work over the past 23 years initiated and led to commercial energy development on the Blackfeet and Cut Bank, in the Judith Gap area in central Montana, on the Columbia River Gorge and over the past five years has led to significant development near Casper, Wyoming and more recently the Fairfield Wind, Greenfield Wind and Crazy Mountain Wind projects in Montana.

I have worked as a wind developer with Montana Power Company, Glacier Electric

Cooperative, Inc., Bonneville Power Administration, the Blackfeet Tribe, the City of Livingston, Montana State University, University of Montana, Kennetech Holdings, LLC, Zond Systems, FloWind, Florida Power and Light Company, Enron Wind, SeaWest Windpower, Texas Windpower, Montana Marginal Energy, Inc., and NorthWestern Energy ("NorthWestern") over the past 23 years with the objective of developing wind energy in Montana.

In 2007, in partnership with OSIsoft, I began working with utility companies, forecasters and plant operators to develop WINDataNOW Technology, a set of real-time data tools and techniques that facilitate the integration of variable generation resources into the grid.

I have been project manager on six research projects for the U.S. Department of Energy ("DOE") beginning in 1996. Most recently, in 2009 I was Principal Investigator of the DOE funded project using WINDataNOW! Technology tools to help the operators of the Glacier Wind plant in Cut Bank overcome scheduling and reliability challenges.

In May of 2014, we successfully constructed and placed online the 10 megawatt ("MW") Fairfield Wind qualifying facility ("QF") project near Fairfield, Montana.

II. Summary of Testimony

Q. Could you summarize the issues you will cover in your testimony?

A. NorthWestern's Petition identified three issues in this proceeding:

1. What rate is NorthWestern required to pay Greenfield?
2. What security is adequate security to guarantee Greenfield's performance?
3. Has Greenfield incurred a legally enforceable obligation?

My testimony will provide background information surrounding the Greenfield Wind project that should inform consideration of each of these three issues. I will give an overview of Greenfield's unsuccessful efforts since 2010 to obtain NorthWestern's agreement to sign a power purchase agreement ("PPA") with rates that represent a reasonable approximation of NorthWestern's avoided costs for the Greenfield project.

As to the first issue, I will explain why after years of ongoing and unsuccessful efforts Greenfield ultimately executed a PPA for a single 25 MW project containing the QF-1 tariff rate. As I will explain, that rate is in fact much lower than the rates that were in effect at prior times when Greenfield attempted to exercise its right to sell at the full avoided cost rates under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Dr. Don Reading will provide additional testimony regarding why the QF-1 tariff rate is a more reasonable approximation of NorthWestern's avoided cost rates than the alternative rate proposed by NorthWestern.

I will also describe the steps that Greenfield has taken to obligate itself to a legally enforceable obligation (or "LEO") to sell its output to NorthWestern. As explained in detail below, Greenfield has fully committed to sell its output to NorthWestern and even executed a PPA with a rate representing a conservative approximation of NorthWestern's avoided costs. I will additionally explain the basis for the $500,000 security amount and terms included in the PPA executed by Greenfield. I will explain that the terms Greenfield included in the PPA that I signed were derived from conditions developed by NorthWestern for use in other PURPA contracts, and that the severe terms proposed by NorthWestern's Petition would frustrate virtually any developer's ability to finance and construct an un-built QF project.

III. Development of the Greenfield Project

Q. You stated that you have experience and knowledge of development of renewable energy projects. Please explain the steps that a local Montana-based developer must take to develop a project.

A. A site is chosen that is a good combination of wind resource, land availability, transmission, market access, permit-ability and build-ability. Land owners are approached and land leases are secured. Met towers are installed to gather site data and facilitate wind resource analysis. Transmission interconnection studies are initiated and completed. PPA discussions are initiated, and a PPA is secured.

The project is then shopped to potential financiers, partners or buyers on the strength of its assets, i.e. PPA, generator interconnection agreement ("GIA"), permits, wind resource and project economics. Project finance is typically structured such that a tax equity investor is placed to take advantage of the after tax benefits of the project. The remainder of the project finance is supplied through debt and cash equity.

If the project is to be financed as a Montana community renewable energy project ("CREP"), as defined under Montana's renewable portfolio standard law, there are additional burdens on the financing that require that the majority of investment capital come from Montana sources. The biggest single requirement for project finance in the current climate is the need for a draft or executed PPA to be obtained prior to actually raising the many millions of dollars necessary to construct the plant

Q. Please provide a general history of the Greenfield Project.

A. In 2008, we made initial landowner contact, and we installed a met tower to gather site data. In 2010, PPA discussions were initiated with NorthWestern. Also, in 2010, surrounding land owners were approached and land leases secured, and the project was shopped to financiers, partners or buyers on the strength of its assets, i.e. draft PPA, access to transmission, wind resource and project economics. In 2011, transmission interconnection studies were initiated for the site. We expanded our initial site into three QF sites over one mile apart: Fairfield Wind, Greenfield Wind and Front Range Wind.

Q. Where is the project located?

A. It is seven miles northwest of Fairfield, Montana. The site has a NorthWestern 69 kilovolt ("kV") transmission line and a substation installed at Fairfield Wind, in NorthWestern's service territory.

Q. How much money has Greenfield spent on development efforts to date?

A. $163,083.

Q. Can the Greenfield project generate any revenue prior to securing a PPA and selling power to an electric utility?

A. No. As a Montana QF, the project will only be paid for electricity that it delivers to the utility under a PPA. Additionally, the only local market for power in this area is NorthWestern, who is the only logical purchaser of output from the project absent an expensive long-range wheeling transaction.

Q. Have any utility-scale wind projects in Montana been successfully financed and constructed by a QF or other independent power producer without first securing a PPA with an electric utility?

A. Not to my knowledge. On the basis of my knowledge of projects in Montana, both large and small projects including Judith Gap, Glacier Wind I, Glacier Wind II, Rim Rock, Gordon Butte, and Two Dot – all were financed and constructed following securing a PPA.

Q. What made you think that NorthWestern would agree to sign a PPA or buy the electricity?

A. It is my general understanding that PURPA and Montana law require them to do so at the full avoided cost rates.

Q. Is Greenfield a qualifying facility?

A. Yes. Greenfield's most recently updated self-certification is attached to NorthWestern's Petition as Exhibit 2.

IV. Efforts to Secure a PPA

Q. NorthWestern's Petition suggests that Greenfield first contacted NorthWestern regarding its intent to obligate itself to a PURPA PPA in 2014. Is that accurate?

A. No. We have been in continuous contact with NorthWestern since at least 2010.

Q. Is there any evidence of your communications with NorthWestern?

A. Yes. Exhibit MHW-01 contains some of the most relevant communications with NorthWestern related to our efforts to secure a PURPA PPA, as well as related to other matters raised in NorthWestern's Petition and testimony. As demonstrated by that thick exhibit of correspondence and contracts to which we have attempted to obligate Greenfield, we have had a long course of history attempting to obtain a PPA with NorthWestern that began well prior to 2014.

Q. When did you first contact NorthWestern regarding the Greenfield project?

A. In May 2010, WINData requested draft 10 MW QF contracts for both Fairfield Wind and Greenfield Wind at $0.06921/KWh, which was the rate available at that time. (MHW-01 at 5.)

Q. Please detail the various configurations of the project and your efforts to work within NorthWestern's requirements for PURPA projects.

A. The met tower was installed in summer 2008, and a Draft PPA was requested for both Fairfield Wind and Greenfield Wind as 10 MW QFs and for Greenfield as a 20 MW QF in May 2010. We received a draft PPA for the 10 MW Fairfield Wind in September 2010, and on the strength of this, secured the interest of financing partner for the development and construction of three 10 MW QF projects in the area – Fairfield Wind, Greenfield Wind and Front Range Wind.

Land leases for the Fairfield/Greenfield/Front Range projects were finalized in late summer 2010. In 2010, we made numerous calls requesting to negotiate the three final form QF contracts and to setup a meeting with NorthWestern, from September 27, 2010 to January 2011. There was no response at all until Frank Bennett at NorthWestern sent out three draft QF contracts in late January 2011.

NorthWestern Transmission Interconnection studies were initiated for the three projects in April of 2011. During the first half of 2011, we conducted resource analysis, output modeling, transmission studies, permitting reviews, turbine supply research and construction planning in preparation for an end of 2011 commercial operation date for the Fairfield, Greenfield and Front Range Wind 10 MW projects.

In April 2011, in the middle of reviewing redlines of the PPA, NorthWestern's contract administrator, Frank Bennett, sent out a completely new contract with economic curtailment language introduced. NorthWestern shortly thereafter initiated its declaratory ruling proceeding requesting economic curtailment rights from the Montana Public Service Commission ("MPSC") in Docket D2011.7.57. After this occurred, our initial financing partner abandoned the projects due to the utility's obvious resistance to working with QF developers. We filed comments in response to NorthWestern's Petition in Docket D2011.7.57 to protect our rights, and in September 2011, the MPSC rejected NorthWestern's proposed curtailment rights they had imposed unilaterally in our negotiations (Docket D2011.7.57, Order No. 7172).

On September 26, 2011 NorthWestern executed a 10 MW PPA with Fairfield Wind, which included standard curtailment language from the Federal Energy Regulatory Commission's ("FERC") administrative regulations. The levelized price was $66.10/MWh and was below the $69.21/MWh published QF-1 rate. However, after Fairfield obtained a 10 MW contract NorthWestern claimed that it had reached the 50 MW cap for wind projects in its tariff.

Q. What impact did the 50 MW cap have on your efforts to develop Greenfield?

A. NorthWestern claimed that since there were now 50 MW of QFs under contract it was not required to provide a PPA to either Greenfield Wind or any other wind QF and further that it was terminating negotiations with these QFs. (MHW-01 at 16.) On October 30, 2011, we attempted to obligate ourselves for a contract at the tariff rate for Greenfield. (MHW-01 at 20.) NorthWestern did not cooperate, however. Additional investors that were interested in Greenfield lost interest at this time.

Similarly, the 50 MW cap again stopped Greenfield from obtaining a contract in March 2012, shortly after 10 MW of the 50 MW cap had freed up when NorthWestern terminated the initial Fairfield QF PPA. (MHW-01 at 23.)

Q. Did you attempt obtain a contract for Greenfield after the MPSC removed the 50 MW cap from NorthWestern's tariffs?

A. Yes. In December 2012, the MPSC ruled that the 50 MW cap was not consistent with PURPA. On December 7, 2012, the MPSC issued Final Order 7199d, in which it ordered NorthWestern to remove the 50 MW installed capacity limit from Schedule QF-1. We attempted to obtain 10 MW contracts for Greenfield Wind, LLC and Greenfield Wind II, LLC on February 13, 2013, even providing contracts containing the then-applicable rate of $48.25/MWh ($46.97/MWh for Off-Peak Hours and $52.33/MWh for On-Peak Hours) to NorthWestern to which we were prepared to obligate ourselves. (MHW-01 at 29-80.) NorthWestern did not cooperate by honoring these contracts or attempt to negotiate any suitable substitute with a long-term, fixed rate. After the fourth request for PPAs, in which we copied FERC staff, NorthWestern senior management, and the MPSC, a response was finally received from Mr. Bennett on March 5, 2013. This message had a prohibitively un-financeable PPA Draft attached.

On April 2, 2013, the MPSC granted NorthWestern's request to limit the availability of long-term fixed rates to wind QFs during the pending court appeal initiated by NorthWestern. It should be noted that long-term PURPA rates were not available for a project over 10 MW during this entire time from 2010 through 2014 and not available for projects in excess of the 50 MW cap for any size.

Q. NorthWestern suggests in its testimony and in discovery responses that it had no opportunity to provide Greenfield with a non-standard long-term fixed rate because Greenfield never asked for such a rate for a project sized over the size cap for standard rates. Did you ever request the NorthWestern provide a contract containing long-term rates for Greenfield or any other wind project sized above the eligibility cap for standard rates prior to 2014?

A. Yes. In May 2010, after our initial inquiry, I requested a contract for Greenfield Wind as a 20 MW stand-alone project selling to NorthWestern under the then-effective wind proxy rates referred to as rate option 3. NorthWestern's PURPA contract administrator, Frank Bennett, rejected this request and stated that I could not obtain a long-term rate for a project over 10 MW in size. (MHW-01 at 9.) In the words of Mr. Bennett: "Marty, are you sure about the 20 MW for a contract . . . . only option 2 rates are available for QFs larger than 10 MW, and only between competitive solicitations." (MHW-01 at 9.) Option 2 rates are short-term rates, not long-term fixed rates.

NorthWestern has been consistent in its position that long-term, fixed rates are not available for projects over the eligibility cap for standard rates at all times prior to when I executed the disputed PPA for Greenfield as a 25 MW project at issue in this case. In fact, as early as 2007 Mr. Bennett informed me that NorthWestern would not provide a long-term rate for a project over the eligibility cap for standard rates, which at that point in 2007 was only 3 MW. (MHW-01 at 3.) Likewise, in June 2013, when I requested a contract for another WINData project, Coyote Wind, with a proposed capacity of 80 MW, Mr. Bennett rejected the request for long-term rates. He explained: "The QF-1 Tariff does allow facilities such as Coyote with a nameplate capacity greater than 10 MW to request a short-term Agreement under Rate Options 1(b), 2(a) or 2(b) for compensation prior to the next competitive solicitation that Coyote would need to be successful in for a long term Agreement." (MHW-01 at 87.)

Q. Aside from its refusal to provide a long-term avoided cost rate for a project in excess of the size limit for standard rates and its use of the 50 MW cap to refuse to provide a contract, do you have any other evidence that NorthWestern does not take its obligations under PURPA seriously?

A. We obtained internal correspondence from NorthWestern in discovery that is contained in MHW-02. NorthWestern attorney Andrew McLain refers to our attorney's requests to him as "pestering them" and in other emails asks to be taken off the email cc list and apparently seems to not want to be involved in the PURPA contract dialogue. Mr. Bennett made a remark that "I think at this stage everyone has the same feelings." This is pretty clear evidence that NorthWestern does not take its obligations under PURPA seriously.

Q. What is the current configuration of the Greenfield project at issue in this docket?

A. The project is a 25 MW self-certified qualifying facility that is owned by Montana residents.

Q. Have the avoided cost rates for a wind project decreased in the time period during

which you have been in contact with NorthWestern seeking a PPA for Greenfield?

A. Yes, significantly. The relevant QF tariffs published over the time period are included in Exhibit MHW-03. Originally, in 2010-2011, the levelized published QF-1 rate was \$69.21/MWh under Option 3 for wind projects conveying their renewable energy credits ("RECs") to NorthWestern. (MHW-03 at 3.) NorthWestern used the curtailment language and the 50 MW cap to negotiate concessions and lower rates from Two Dot Wind and from Fairfield Wind. Two Dot Wind signed at a reduced rate, plus the contract contained economic curtailment rights for NorthWestern.

Fairfield Wind was pressured to sign at \$66.10/MWh, even after NorthWestern's curtailment language was rejected by the MPSC. Fairfield Wind's second, and current, PPA was signed in 2012 at \$90.87/MWh on-peak and \$54.44/MWh off-peak, which calculates out to approximately \$63.16/MWh plus an average price of approximately \$8.57/MWh for RECs.

As I stated earlier, NorthWestern used the 50 MW cap to prohibit Greenfield from obtaining these higher rates that were previously available from 2010 to 2012.

The most recent QF PPA requests at issue in this case have been made with a published QF-1 rate approved September 1, 2013. That rate is \$53.14/MWh off-peak and \$58.50/MWh on-peak, which calculates to approximately \$54.42/MWh. (MHW-03 at 28.)

Q. NorthWestern stated in its testimony that Greenfield also attempted to sell the output of this project to NorthWestern as a CREP, as defined under Montana's renewable portfolio standard. Could you explain the actions you took to sell the output of the Greenfield project under a CREP structure?

A. After facing seemingly insurmountable barriers to obtaining a PURPA PPA for Greenfield at the full avoided cost rates, we decided to explore other market opportunities with

NorthWestern. NorthWestern has a CREP requirement as part of its renewable procurement requirements and therefore has more incentive to secure CREP projects than QF projects without CREP status.

Since late 2011, we have proposed selling the output or the entire Greenfield project itself to NorthWestern under various structures designed to meet the local ownership rules for a CREP, and have bid the project into NorthWestern's CREP request for proposals ("RFP").

We have also bid WINData's other projects into CREP RFPs, and as NorthWestern notes in its Petition one of our projects, Crazy Mountain Wind, won the most recent CREP RFP. Ultimately, on February 26, 2014, the MPSC disapproved Crazy Mountain's financing structure as qualifying as a CREP and instead stated that majority Montana ownership must be in place from the first day and continue every day following. NorthWestern has consistently taken the position that the developer must take the risk of approval of the CREP structure even though MPSC Staff has informed us on several occasions that the administrative rules require NorthWestern to petition for certification of the CREP project prior to execution of the PPA. (Exhibit MHW-01 at 99-100.) This is another example of how NorthWestern consistently uses its bargaining power to place unreasonable risks on project developers.

Greenfield was also bid into that same RFP, and we would have been willing to try to help NorthWestern meet its CREP requirement under commercially reasonable terms and a different project structure than that proposed for Crazy Mountain. Ultimately, it did not appear to be possible to reach financeable and reasonable enough terms with NorthWestern, and we elected to assert our rights to sell at the full avoided cost rates without guaranteeing a CREP structure.

Q. Is it more difficult to develop a CREP project than a regular QF project?

A. Yes, it is significantly more difficult to finance, build and operate a CREP project. Typically, tax equity financiers require 98-99% ownership and revenues for 10 years prior to surrendering the project revenue to the local sponsor. A non-CREP QF project can use conventional financing structures, and is not limited to local Montana residents.

Q. You indicated that the CREP project must be owned by Montana residents. In your experience are there many sources of equity investment from Montana investors for a project that costs as much as a 25 MW wind project?

A. No. The capital expenses ("CAPEX") for a 25 MW wind farm is between $40-50 million. Typical wind project financing structures normally place up to 50% of the CAPEX as tax equity finance, in which the investor takes its return as after tax values. There are currently about 20 corporate investors that provide tax equity investment and have tax bills high enough to be able to monetize tax credits and depreciation as a return on $25 million in tax equity investment. None of these large tax equity investors is a Montana resident.

Q. Do you understand PURPA to require you to structure your QF project as a Montana CREP in order to receive the full avoided cost rates?

A. No, that is not my understanding. In a discovery response to PSC-06(d), NorthWestern itself appears to agree that a QF project does not need to be a CREP project, but it can be if it chooses.

Q. Would you have offered to sell the output of the project as a CREP project if you had been able to sell the output at full avoided cost rates as a non-CREP QF with commercially reasonable terms?

A. No.

Q. Could you explain your motivation for attempting to sell the output of the project as

a CREP structure?

A. NorthWestern had blocked all of our attempts to get a PPA with long-term avoided cost rates for Greenfield since 2010. In light of this reality, responding to the 2012 and 2013 CREP RFPs was our only path to a PPA. It was our intent and motivation to obtain NorthWestern's signature on the contract, so we could finance and build the Greenfield project.

Q. Have your efforts to sell the project as a CREP project in any way diminished your willingness to sell the output of the project as a non-CREP qualifying facility at the full avoided cost rates?

A. No.

V. Creation of a Legally Enforceable Obligation

Q. Can you explain the actions you took to commit to sell Greenfield's output to NorthWestern?

A. We sent in the signed PPA earlier this year to establish an LEO for Greenfield as a single 25 MW project after years of frustration in being blocked by NorthWestern in our requests for a QF contract that we are legally entitled to under PURPA. NorthWestern did not provide the PPA and interconnection agreements with its Petition, but these are contained in Exhibit MHW-01. (MHW-01 at 160-335.)

Q. Please describe the terms of the PPA that you signed.

A. We used the contract draft that NorthWestern supplied in the 2014 CREP RFP as our template. We used the published QF-1 rate in Docket No. D2012.1.3, Order 7199d. That rate is \$53.14/MWh off-peak and \$58.50/MWh on-peak, which calculates to approximately \$54.42/MWh. We obtained this rate from NorthWestern's tariff website. We offered to include \$500,000 as a default security that provides assurance the project will achieve its commercial online date and also is a source upon which the utility could draw for a default occurring throughout the term of the contract. This is consistent with security amounts that were in the Fairfield Wind PPA and other recent QF PPAs provided by NorthWestern and signed in the last few years of which we were aware at the time of signing the contract at issue here.

Q. Do you understand your actions to have obligated Greenfield to sell at the QF-1 tariff rate under a legally enforceable obligation?

A. I do not intend to provide legal conclusions and will reserve legal argument for legal briefing. However, I can state that I was well aware of FERC's orders regarding formation of a legally enforceable obligation when I took action on behalf of Greenfield to sign the contract at issue in this proceeding.

Specifically, FERC has explained this right as follows:

> [A] QF has the option to commit itself to sell all or part of its electric output to an electric utility. While this may be done through a contract, if 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 non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA. Accordingly, a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.

(*JD Wind 1, LLC*, 129 FERC ¶ 61,148, at P 25 (2009).)

FERC has more recently explained:

> 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.

(*Grouse Creek Wind Park, LLC*, 142 FERC ¶ 61,187, at P 40 (2013).)

Greenfield intended to leave no doubt as to our commitment by actually signing the contract.

Q. NorthWestern states in its Petition that the existing MPSC orders establish that a QF can create an LEO only by tendering an executed PPA to the utility with a price term consistent with the utility's avoided costs and containing other reasonable assurances and guarantees, along with an executed interconnection agreement. Were you aware of that test when you attempted to create an LEO?

A. Yes. I have read the order to which NorthWestern refers, and it states as follows:

> To establish an LEO, a QF must tender an executed power purchase agreement to the utility with a price term consistent with the utility's avoided costs, with specified beginning and ending dates, and with sufficient guarantees to ensure performance during the term of the contract, and an executed interconnection agreement. The executed contract demonstrates an unconditional commitment. If the utility also executes the contract, the utility would be able to enforce the obligations undertaken by the QF. Interconnection expenses may be so high as to derail an otherwise feasible project. Only by acknowledging and agreeing to an interconnection agreement can a QF demonstrate that it is prepared to proceed despite any interconnection obstacles. Further, an interconnection agreement requires that a QF have sufficiently defined its project and made adequate progress that the project would be more than a mere speculative, paper proposal.

(*In re Whitehall Wind, LLC*, Order No. 6444e, Docket D2002.8.100, ¶ 47 (2010).)

We were aware of and intended to satisfy these requirements for Greenfield to the best of our ability.

Q. Did Greenfield submit an executed contract containing a price term consistent with NorthWestern's avoided costs?

A. Yes. The PPA contains the prices in the QF-1 tariff in effect at the time of execution, which contains significant discounts to account for the lower capacity value of wind resources. The PPA also places the burden on Greenfield to pay the applicable wind integration and contingency reserve requirements from NorthWestern's tariffs. The reason I used these rates is discussed below, and the accuracy of these avoided cost rates is discussed in detail by the accompanying testimony of Dr. Don Readıng.

Q. Did the contract you executed contain specified beginning and ending dates?

A. Yes. As stated in the LEO contract, the commercial operation date is December 31, 2015 and the LEO contract shall be effective at 12:01 a.m. prevailing Mountain Time and shall remain in effect for a term of 25 years following the first day of the first month immediately following the commercial operation date, unless earlier terminated pursuant to its terms.

Q. Did the contract you executed contain sufficient guarantees to ensure performance during the term of the contract?

A. Yes. These guarantees are explained in further detail below.

Q. Did you also submit executed interconnection agreements?

A. Yes. We submitted executed small generator interconnection agreements ("SGIA") for both Project #134 and #153 that will be constructed at the existing Fairfield Wind substation and allow for interconnection of the total 25 MW. Originally, SGIA #134 was for 10 MW Greenfield Wind, LLC and project #153 was for 15 MW for Greenfield Wind II, LLC, but collectively they allow for all interconnection upgrades needed for the 25 MW project proposed in this case. NorthWestern indicated in discovery that the interconnection costs for these two SGIA projects are the same as it would expect for a single 25 MW request under its Large Generator Interconnection Procedures ("LGIP"). This discovery response is Exhibit MHW-04.

Q. Are you aware that the district court has since invalidated the Commission's Whitehall Wind Order No. 6444e, establishing this bright line LEO test?

A. Yes. I understand that the district court rejected the MPSC's bright lıne test and instead indicated that a utility's refusal to negotiate can create an LEO even before the QF signs a contract.

Q. Has NorthWestern refused to negotiate with Greenfield for a PURPA contract?

A. Yes, NorthWestern has relied on the use of the 50 MW cap and the short-term only rate for projects over 10 MW over the years as a refusal to negotiate.

Q. What was the rate that was in effect at the time that NorthWestern first refused to sign a contract?

A. NorthWestern first refused in May 2010, when I requested a contract for Greenfield Wind as a 20 MW stand-alone project selling to NorthWestern . As I explained earlier, Mr. Bennett, rejected this request on the basis that only short-term rates were available for Greenfield at a size above the eligibility limit for standard rates. (MHW-01 at 9.) NorthWestern has effectively refused to negotiate for a non-standard contract over the eligibility size cap at all times since then up until it filed the Petition in this case proposing a new method to calculate rates for such projects.

NorthWestern also refused to sign a contract on April 13, 2011 for Greenfield at a size of 10 MW, when Frank Bennett at NorthWestern sent us a completely new contract containing unfinanceable economic curtailment requirements. This occurred in the middle of us finalizing the terms of the draft QF contract he sent us on January 20, 2011 for Greenfield Wind and for Front Range Wind (now renamed Greenfield Wind II). The QF-1 tariff rate, Option 3 for wind installations conveying RECs to NorthWestern, was $69.21/MWH at that time. (MHW-03 at 3.) NorthWestern again refused to sign on September 29, 2011, when Frank Bennett at NorthWestern refused Greenfield's request for a QF PPA saying that, "Therefore, as NorthWestern is bound by the provisions of its QF-1 Tariff, NorthWestern is prohibited by this tariff language from signing any new wind QF contract that would cause NorthWestern to exceed the 50 MW Installed Capacity Limit." The QF-1 tariff rate was still $69.21/MWh at that time. Clearly, there is actually an argument that Greenfield is entitled to a much higher rate than what we put in the LEO contract based on the district court's Whitehall opinion.

Q. NorthWestern has suggested through its Petition and discovery responses that it had no opportunity to negotiate a long-term avoided cost rate after you attempted to create an LEO for a 25 MW project. Do you have any response to this?

A. The emails in Exhibit MHW-01 demonstrate otherwise. After I sent in my last LEO notice in April 2014, NorthWestern's point of contact at this time, Bleau LaFave, responded to indicate that the tariff rate was unavailable for a 25 MW project, and I requested in response that Mr. LaFave send me NorthWestern's proposed indicative pricing. (MHW-01 at 336.) However, NorthWestern had already filed their Petition prior to even contacting me.

VI. Avoided Cost Rate

Q. NorthWestern states that you should have used a rate generated by its power supply model instead of the QF-1 tariff rate. Did NorthWestern ever propose use of this power supply model for the Greenfield project prior to filing its Petition in this case?

A. No, not prior to filing the Petition on April 23, 2014. Bleau LaFave mentioned "a new way of modeling avoided cost" that he was using in May 2014 and informally told me on a call that NorthWestern could offer around $50/MWh levelized over 25-years for the 25 MW Greenfield Wind QF. He did not share any further detail. The first I heard of the specifics of the power supply model was in his testimony attached to NorthWestern's filing. However, as noted above, I had asked for their proposed indicative pricing on April 23, 2014. (MHW-01 at 336.)

Q. Did NorthWestern ever provide you with access to the power supply model for the Greenfield project prior to filing the Petition in this case?

A. No. Additionally, NorthWestern stated in discovery in this case that they will not allow third parties to access their models.

Q. To the best of your knowledge, has the MPSC ever approved use of NorthWestern's power supply model for purposes of calculating avoided cost rates?

A. No, not to the best of my knowledge.

Q. Would it have been possible for you to be able to accurately guess the rate that NorthWestern's power supply model will produce and the Commission will approve prior to signing the contract under the circumstances presented in this case?

A. No.

Q. Has NorthWestern ever provided you with the option to sell under long-term avoided cost rates for the full output of the 25 MW Greenfield project?

A. No, the only option was the short-term rate in the tariff between competitive solicitations but there are never competitive solicitations for QFs. As I explained above and as the attached emails demonstrate, from 2007 until the time I signed the PPA at issue, NorthWestern consistently maintained that QFs over the eligibility cap for standard rates could not obtain long-term fixed avoided cost rates.

Q. What basis do you have to conclude that the short-term rate provided by NorthWestern is not a reasonable or legal rate for the 25 MW Greenfield project?

A. On August 7, 2013, the Greenfield Wind owners, WINData LLC and Montana Marginal Energy, joined with Hydrodynamics, Inc., Montana to file a "PETITION FOR ENFORCEMENT AND DECLARATORY ORDER PURSUANT TO SECTION 210(h) OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978" under FERC Docket No. EL13-73-000. Without providing a legal opinion, my understanding is FERC determined that NorthWestern's policy of providing no fixed, long-term rate outside of the 50 MW cap or for projects not entitled to standard rates is inconsistent with PURPA, and it issued an order to that effect.

Q. Why did you choose to insert the QF-1 tariff rate into the contract?

A. This is the only reasonable option given the choices.

Q. NorthWestern states that you erroneously included an off-peak rate of $53.95/MWh, while the off-peak rate in the tariff is $53.14/MWh. Could you explain the discrepancy?

A. This was simply a typo. The cover email that I used when sending the contract clarifies that we intended to obligate ourselves to the Option 1(c) rate in Schedule No. QF-1, subject to reductions as permitted by Schedule No. CR-1 and Options 2(c) of Schedule No. WI-1. (MHW-01 at 162.)

VII. Performance Security Guarantee

Q. NorthWestern argues that the performance security guarantee that you included in the executed contract is inadequate. Please describe the performance security terms that you included in the PPA.

A. In the Fairfield Wind QF PPA, NorthWestern required $180,000 to cover delay security damages for up to 180 days after the proposed commercial operation date. Fairfield is a 10 MW QF project, so for a 25 MW QF project the comparable amount of security would be $450,000. We decided to round it out to an even $500,000 for simplicity. This delay security gives NorthWestern the right to collect $750/day per that the project is not yet online after the proposed commercial operation date of December 31, 2015, unless NorthWestern could obtain replacement power for a lower cost. (MHW-01 at 184.) The contract we signed provides 90 business days to post the security, which is likewise consistent with the successfully completed Fairfield Wind QF PPA contract. Additionally, after the project achieves commercial operation, the contract I signed allows NorthWestern to retain the $500,000 security throughout the term of the contract to secure any future defaults. This right to draw on the security throughout the contract derives from the template PPA NorthWestern used in its 2014 CREP RFP, and we included that right even though NorthWestern does not always require any ongoing security after commercial operation from other QF projects. The applicable sections of the contract are Section 7 in the contract that we signed. (MHW-01 at 183-184.)

Q. Are these default security requirements included in the contract you executed consistent with terms contained in similar PPAs?

A. Yes. We derived the terms from PURPA contracts, including the Fairfield Wind contract and the various drafts that were provided by NorthWestern themselves and other developers over the past four years. They are also consistent with Section 3 in the draft PPA created by Frank Bennett and provided to Greenfield on March 8, 2012.

Q. NorthWestern suggests in its testimony that Greenfield should be required to submit $1.5 million as default security. Do you agree that is a reasonable amount?

A. No, this amount is prohibitive and places an unreasonable burden on the project.

Q. NorthWestern also suggests that Greenfield should be required to post the default security amount within 15 days of NorthWestern signing the contract. Do you consider that proposal to be reasonable?

A. No, this short amount of time is also prohibitive and places an unreasonable burden on the project.

Without NorthWestern's signature on a PPA, it would be virtually impossible to raise the money to post the security from lenders, and 15 days is far too short even after NorthWestern signs the contract.

We will attempt to perform on whatever requirement the MPSC deems reasonable, but the reason that most small Montana QF and CREP projects default is that NorthWestern's contracts contain commercially unreasonable conditions, such as posting a large security within 15 days, transmission curtailment risk, and CREP certification risk.

It is not possible for a small Montana-based community-scale developer to raise that amount of cash in that short amount of time, and terms like this frustrate the ability of local entities to develop renewable energy projects.

Q. Prior to the filing of the Petition in this case, has NorthWestern ever requested inclusion of $1.5 million that must be posted within 15 days for the Greenfield project?

A. No. The amount that was under discussion for the security on the Greenfield CREP PPA was $1,000,000 which also was to be maintained to secure the life-time production/performance of the project, something that NorthWestern has not always applied to a QF which is compensated on an as-produced power generation basis, with no guarantees of production. Additionally, there are additional needs for security in a CREP PPA where NorthWestern may be relying on the QF to meet its CREP requirements.

Q. Is it possible to evaluate the reasonableness of NorthWestern's proposal from the material supplied with its Petition?

A. No. NorthWestern's testimony provides only 15 lines of a description of its proposed performance security provision and provides no contract terms it recommends as reasonable. (LaFave, BJL at 16-17.)

The terminology in the PPA is critical to a determination of whether the clause is reasonable and the PPA financeable. NorthWestern failed to provide a proposed contract that would demonstrate how it would implement its security provisions. Approving NorthWestern's

Petition would be a blank check to allow NorthWestern to draft a completely unworkable contract even if $1.5 million and 15 days were somehow determined to be reasonable conditions.

Q. Would it have been possible for you to be able to accurately guess the performance security amount that NorthWestern now proposes and include it in an executed contract?

A. No. It would be impossible still because they didn't provide a contract with specific terms with their testimony.

Q. NorthWestern states on page 9 of its Petition that you have intentionally delayed development of other projects, and an increased security requirement is therefore warranted for Greenfield. Do you agree?

A. No. We did everything in our power to finance and construct the Fairfield Wind project under the initial PPA for that project. NorthWestern resisted working with Lincoln Renewable Energy such that WINData had to buy back the Fairfield Wind project and seek out Foundation Windpower to eventually get the QF project built. Ultimately, we were successful and the project is now online.

It was NorthWestern that refused to provide reasonable PPAs, negotiate fairly and even later refused to reasonably flex on non-commercial terms such as the assignment term of the contract and Force Majeure language that were requirements from our financiers.

The actual problem with these past projects was NorthWestern and its unwillingness to cooperate and its contractual requirements that place entirely unreasonable risks on the projects.

VIII. Conclusion

Q. Is Greenfield still committed to sell its output to NorthWestern at the full avoided cost rates in effect at the time you executed the contract?

A. Yes.

Q. Do you have any concluding remarks?

A. NorthWestern's proposed application of FERC's LEO rules would impose on Greenfield the impossible burden of somehow "guessing" NorthWestern's preferred avoided cost rates and default security terms. Aside from the question of whether such a test complies with federal and state law, it is my opinion that such a test would entirely frustrate a QF's ability to exercise its right under PURPA to unilaterally create an LEO. Since 2010, we have made continuous efforts to work within a shifting set of requirements and have done everything that could be done to obligate the Greenfield project to sell its output to NorthWestern.

Oregon Public Utility Commission

Docket No. UM 1610, Direct Testimony of Ormand Hilderbrand

Mar. 18, 2013

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

IN THE MATTER THE PUBLIC UTILITY COMMISSION OF OREGON	)	**CASE NO. UM 1610**
Investigation Into Qualifying Facility Contracting and Pricing	)	

Community Renewable Energy Association

Exhibit 100

Direct Testimony of Ormand Hilderbrand

March 18, 2013

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Ormand G. Hilderbrand and my business address is 71190 N. Klondike Road, Wasco, Oregon 97065.

Q. Please describe your professional background.

A. After over 30 years of international infrastructure project development, I started PáTu Wind Farm on my family's farm outside of Wasco, Oregon. I was responsible for sourcing financing, negotiating contracts, overseeing project construction and startup. Since commercial operation in December 2010, I have been the general manger of PáTu and solely responsible for day to day operations. I have also been a member of the American Wind Energy Association since 2005. Additionally, I am a member of the board of directors of the Community Renewable Energy Association ("CREA").

Q. Have you testified in previous cases before the Public Utility Commission of Oregon?

A. Yes. I have submitted testimony in a qualifying facility ("QF") complaint docket, *PáTu Wind Farm LLC v. Portland General Electric Company* (UM 1566). However, at the time of filing this pre-filed testimony, that case has not yet progressed to a hearing.

Q. On whose behalf are you testifying?

A. I am submitting testimony on behalf of CREA.

Q. What is CREA's interest in this proceeding?

A. CREA is a Chapter 190,[1] non-profit, intergovernmental association dedicated to promoting favorable state and federal policy for all community renewables recognized in

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1 O.R.S 190.003 *et seq.*

Oregon's Renewable Portfolio Standard (biomass, geothermal, hydropower, ocean thermal, solar, tidal, wave, wind and hydrogen). CREA is comprised of several counties which provide active participation through their county commissioners. These include Sherman, Wasco, Gilliam, Harney, Hood River, Lincoln, Morrow, Polk, Union, Wheeler along with the Mid-Columbia Council of Governments, Eastern Oregon Rural Alliance, and Lake County Resource Initiative. Additionally, more than twenty businesses are members who have interest in a viable community renewable energy sector for Oregon.

Q. What is the purpose of your testimony?

A. I will first provide testimony on community renewable energy projects and the importance of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Then, I will specifically address the following issues raised in Phase 1 of this docket, as set forth in the Administrative Law Judge's ("ALJ") Procedural Order on December 21, 2012: Issue 3: Schedule for Avoided Cost Rates; Issue 5: Eligibility Issues; Issue 6: Contracting Issues (B., I., and E.). I will also respond on these topics to the direct testimony of the three investor-owned utilities: Idaho Power Company ("Idaho Power"), Portland General Electric Company ("PGE"), and PacifiCorp (collectively the "utilities" or "IOUs"). CREA's witness Dr. Don Reading will address the following issues: Issue 1: Avoided Cost Price Calculation; Issue 4: Price Adjustments for Specific QF Characteristics; Issue 5: Eligibility Issues; and Issue 6: Contracting Issues (B. and I. only). CREA's other witness, Mr. Tom Svendsen, will provide testimony addressing Issue 2: Renewable Avoided Cost Price Calculations, and Issue 4, Price Adjustment (as it pertains to renewable avoided cost rates).

Q. Please summarize your recommendations.

A. In general, I disagree with several of the suggestions of the IOUs which would retract the

Public Utility Commission of Oregon's ("OPUC" or "Commission") modest policies aimed at providing a fair and stable environment for qualifying facilities. As other CREA witnesses and I will explain, many of the IOUs' proposals would have a very detrimental impact on community renewable energy projects in Oregon. I recommend that the Commission not accept several recommendations of the IOUs which would undermine the ability of small developers to take advantage of their right to enter into a long term contract with a utility at the avoided costs. My testimony will follow the order of the ALJ Ruling's Issues List for the items I will address. A summary of CREA's responses to all of the itemized questions by the ALJ Ruling for this phase is contained in CREA/101.

II. Community Renewable Energy and the Importance of PURPA

Q. What is community renewable energy?

A. Usually community renewable energy refers to projects of 20 MW or less that have substantial local ownership. Studies at Oregon State University, University of Minnesota, and the National Renewable Energy Laboratories have documented that locally owned projects provide greater economic benefit to the local community than that which would be provided by a larger, absentee-owned project.[2] These studies have demonstrated that there can be a three to five-fold increase in economic returns and benefits to the local community over a larger, utility scale project. Simply put, with local investors the economic returns stays with the local community as juxtaposed with a larger developer with outside investors. Therefore, CREA

[2] *See* E. Lantz and S. Tegen, National Renewable Energy Laboratory, *Economic Development Impacts of Community Wind Projects: A Review and Empirical Evaluation*, ((April 2009) , available online at http://www.nrel.gov/docs/fy09osti/45555.pdf (last accessed March 16, 2013).; M. Torgerson, B. Sorte, and T. Nam, Oregon State University, *Umatilla County's Economic Structure and the Economic Impacts of Wind Energy Development: An Input-Output Analysis* ((March 2006), available online at http://ruralstudies.oregonstate.edu/sites/default/files/pub/pdf/umatilla_sr1067.pdf (last accessed March 16, 2013).

believes that local ownership will result in increased economic development impacts. For example, at the community wind farm I operate in Sherman County, Oregon, the 9-MW PáTu Wind Farm LLC ("PáTu"), we have made a concerted effort to have a local impact. During construction, we provided high-paying jobs to local steel workers and others, and contracted with local contractors and service suppliers whenever possible. Since commercial start-up, PáTu has continued to pay approximately $300,000 annually to contract labor and technical service firms in the region.

Q. What are some of the difficulties and obstacles with developing a community scale project?

A. Smaller scale, community renewable projects face all the same obstacles as larger, utility scale projects – such as environmental permitting, land use laws, transmission access, and interconnection rights. However for smaller projects the issues of financing and negotiating power purchase rates are much more difficult than for larger projects. In regards to financing, trying to finance a $20 million community renewable project is almost impossible. Banks and financing institutions much prefer larger loan amounts where the risk can be syndicated amongst several institutions. As Tyler Fauerbach, Senior Vice President, Power Finance - Energy Industries Division, for U.S. Bank told me in 2009 – make your project bigger and add another "0" on to your loan request amount and then come back to us. In other words, U.S. Bank has interest in $200 million but not $20 million project loan amounts for renewable energy. At $200 million, the project has the critical mass to attract other partners to share the risk and expertise in evaluating the loan. And then you have the problems of actually negotiating a power purchase rate with a "monopoly" utility purchaser. With this negotiation the cards are stacked against the small business person who is trying to start a community renewable energy project. I, as the small business person, simply did not have the resources to successfully negotiate a long-term power purchase agreement with an IOU. The IOU has all the resources to access independent studies and legal assistance.

Q. Could you provide some examples of community renewable energy projects?

A. Oregon has the 9-MW PáTu Wind and Lime Wind, a 3 MW community wind project outside of Baker City owned and developed by the Randy Joseph family from the Baker City area. In Washington there is Coastal Wind out of Grays Harbor. Coastal Wind is a 6 MW community wind project that is owned by the Coastal Community Action Program. This project provides more than $500,000 through the Community Action Program to the community. Minnesota leads the way for integrating a healthy community energy sector through the Community Based Energy Development ("C-BED") program that stimulates local community investment in renewable energy projects. As of June 30, 2008, there are a total of 57.3 MW of C-BED projects completed, another 57 MW of C-BED projects under contract, and an additional 721 MW of C-BED projects in negotiation. Although these are examples of community wind projects, the community ownership models can also apply to other renewable resource types.

Q. Does Oregon's Renewable Portfolio Standard refer to community renewable energy projects?

A. Yes. I am not an attorney, and cannot provide a legal opinion. However, it is important to note in this context that Oregon's RPS law specifically calls out community renewable energy projects. Specifically, the Oregon RPS statute states:

> The Legislative Assembly finds that community-based renewable energy projects are an essential element of Oregon's energy future, and 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. All agencies of the executive department as defined in ORS 174.112 shall establish policies and procedures promoting the goal declared in this section.[3]

Unlike the other RPS goals, this goal cannot be easily met by building a few large renewable energy plants because each project must be under 20 MW. One would expect that would take an effort over a longer period of time to achieve online status for a large number of community-based renewable energy projects.

Q. Are you aware of any policies or procedures of the Public Utility Commission of Oregon promoting this goal to promote projects with capacity of 20 megawatts or less?

A. No, not specifically. The Commission did implement policies applicable to qualifying facilities under 10 MW in docket UM 1129. However, the utilities in this docket have advocated to eliminate many of the benefits of those policies established in UM 1129.

Q. Are you aware of any policies that the individual utilities have in place to meet the 8% goal by 2025?

A. No. When asked in discovery, none of the utilities in this docket were able to explain any specific policies they have in place to meet this goal. It is not clear how the utilities will meet this goal, which will require acquisition of a substantial number of projects under 20 MW. For example, PGE has provided its load forecast only out until 2021, and stated load in that year will be in excess of 2,500 aMW. To reach the 8% goal, PGE would need 200 aMW of projects sized under 20 MW. That would require 20 separate 10-MW projects with an unrealistically high capacity factor of 100%. If the goal were met with wind projects, it would require approximately

[3] ORS § 469A.210.

600 MW of wind projects, which would be 60 different 10-MW projects. PGE does not have anywhere near that level of projects currently, and has proposed to make it much more difficult for projects below the 20-MW size to obtain contracts through the mandatory purchase provisions of PURPA.

Q. Do you believe that PURPA is important to community energy projects?

A. In my experience, transacting with a utility through the PURPA is one of the only means by which small, independent developers of renewable energy facilities may be able to sell renewable energy. Proper implementation of PURPA is logically a critical element of providing community scale projects with the ability to sell to an investor-owned utility.

III. Issue 3: Schedule for Avoided Cost Rates

Q. Have you considered the issues contained in Issue 3, regarding the schedule of avoided cost rate updates?

A. Yes. Those issues are as follows:

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

Issue 3. B. Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate?

Issue 3. C. Should the Commission specify what factors can be updated in mid-cycle? (such as factors including but not limited to gas price or status of production tax credit.)

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

Issue 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?*

Q. Does CREA have a formal position on these issues?

A. CREA does not have any specific recommendations to change the current system at this time. However, we remain open to suggestions from other parties and have a general position that the Commission should adhere to two principles in addressing the updates to avoided cost rates: fairness and predictability.

Q. Could you explain fair treatment?

A. First, the schedule and timing for updates should be fair and unbiased with regard to whether rates are going up or down. When a utility wants to update the rates, it can do so very quickly by including new inputs into the rate calculation model and filing the new rates to become effective. Small QFs do not have the resources to recalculate the avoided cost rates and obtain immediate revision when the standard rates are too low. There should be a neutral and transparent trigger to change the rates. Allowing the rates to only change when a utility files to change them, will only result in bias in favor of frequent and prompt updates when the rates are decreasing and infrequent and slow updates when rates are increasing. That is not fair.

Q. Could you explain predictability?

A. Small QFs need predictability. The purpose of standard rates is to provide rates that are transparent and publicly available for small QFs to use in deciding whether to pursue development of their project. Currently, the Commission requires the rates to be updated every two years and within 30 days of the acknowledged Integrated Resource Plan. Even with this guidance, the rates can change in an unpredictable fashion if a utility files to reduce the rates out of cycle. Even if the rates change during the normal cycle, very few small QFs will be aware of when the rates are next scheduled to change.

Q. Why is predictability important?

A. Changing rates or even if there is a possibility that rates will change will put a small community renewable project at risk of not being able to obtain financing. As I already stated, the difficulty of obtaining financing for a small project is extremely high. Typically, the small project will need to cultivate relationships with several different potential financers for a few years before reaching the point of having a final financial partner who will fund the project. Even then, the financer will not finally agree to fund the project until the PPA is executed. During this entire process, banks and financial institutions only want to work with known facts on the critical areas that affect a project's income streams. Introducing a variable of non-predictability in the income stream of a business plan for a small project simply is a "deal killer."

PáTu's search for financial partners had to be restarted when the published rates changed effective September 9, 2009, in Advice No. 09-16, because up to that point in my discussions with potential financers I had been relying on the higher rates that were in place since November 1, 2007, in Advice No. 07-27. I knew this was going to happen and was open with the possibility of rate changes with my financial institutions. However, banks stepped away and I nearly lost all abilities to finance the project. Imagine what would happen with more frequent rate changes or the ability not to know what your firm rate was to be until the PPA was executed – as would be the case with the proposals to require negotiation of rates for projects over 100 kW. These tactics will stop all possibility of small projects to obtain financing. CREA is not in favor of any changes that would decrease the predictability because such a change will work to discourage community-scale projects.

Q. Do you have a response to any of the proposals by the utilities with regard to changes in the current rate updates?

A. Yes. PGE's direct testimony has proposed changes that would make it nearly impossible for small QFs to predict when the rates might change.[4] PGE appears to propose to conduct separate updates to the standard avoided cost rates each time there is a change in the forward energy prices, gas prices, fixed and variable operation and maintenance, and the demarcation between sufficiency and deficiency. Although PGE's proposal is not entirely clear, it appears that there could be several rate updates within the same year. In my opinion, as I stated above, this would lead to very unpredictable rate changes and seriously undermine the entire purpose behind standard avoided cost rates for small projects without the resources to follow all of these market indicators.

Q. Do you have any further recommendations on this issue at this time?

A. I understand the utilities' largest concern to be that the rates can become out-dated within the two year cycle if the gas prices change. I am aware that the Idaho Public Utilities Commission recently resolved this concern in that state by requiring a single annual update to the rates at a pre-determined time based upon the transparent gas forecast of the Energy Information Administration ("EIA"), which is released once a year. The Idaho Commission stated, "to avoid confusion, ensure consistency, and alleviate gamesmanship, we find it necessary for all three utilities to update their annual SAR gas forecast on the same date, and to also update their annual IRP forecasts on a uniform date."[5] This is a reasonable resolution to the concern with two year updates, which also provides QFs with predictability and fairness as to the time when the rates will change. The OPUC could resolve the concerns here by requiring an annual update based upon a transparent indicator like the EIA gas forecast and a predetermined date that is the same

[4] *See* PGE/100, Macfarlane-Morton/16,

[5] *See In Re Review of PURPA Contract Provisions Including the Surrogate Avoided Resource (SAR) the Integrated Resource Planning (IRP) Methodologies for Calculating Avoided Cost Rates*, Idaho Public Utilities Commission Case No. GNR-11-03, Order No. 32737, at 15-16 (2013).

each year.

IV. Issue 5: Eligibility Issues

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

Q. Do you believe that the Commission should lower the eligibility cap for any resource types?

A. No. As I mentioned above, Oregon's RPS actually instructs the Commission to implement special policies for community-scale projects up to 20 MW. The utilities are proposing to go in the wrong direction.

Q. What impact would lowering the eligibility cap have on community-scale development?

A. Simply put, lowering the eligibility cap will stop any development of community renewable energy in Oregon. I am not a large, multinational company. In response to Idaho Power witness Stokes's claim that all QFs are large, multinational companies[6] - PáTu is owned by my brother and myself – small business professionals who wanted to invest in renewable energy within our community. Without the certainty of firm power purchase agreements and the predictability of the rates available, I would not have been able to obtain financing. Moreover, I have to ask myself what would happen to existing projects such as PáTu if the eligibility cap is lowered? I did not invest my life savings and bet the family farm, which has been in our family for more than 120 years, for an investment that has a 20 year life. PáTu will need to re-apply for financing in 15 years or so when my existing PPA expires. The refinancing will be required to replace the existing turbines with more efficient units. I sincerely doubt that I will be able to

[6] Idaho Power/100, Stokes/46-47.

refinance to extend the life of PáTu if the IOUs are successful in reducing the eligibility cap for community renewable energy projects. If the cap is reduced I will have few options but to sell PáTu to a larger project owner who will have the financial resources to re-finance when the time comes.

Q. Do you believe that a small community scale project like PáTu would be able to negotiate its rates and all contract terms with an IOU?

A. Absolutely not – I do not have Warren Buffet's resources at PacifiCorp, PGE's nor Idaho Power's. Prior to execution of a PPA, a small project has to invest its capital in project development basics – engineering, land leasing, legal formation, wind resource analysis, transmission and interconnection access, cultural and historical studies, environmental studies, and financing to name some of the major cost factors. I would not have had the resources to spend on a consultant qualified in negotiating complex economic models for pricing with a utility.

Q. PGE theorizes that because a 10 MW project costs tens of millions of dollar to construct and operate, 10 MW QFs should be able to afford attorneys and economists to engage large utilities in rate negotiations.[7] Do you agree?

A. No. The tens of millions of dollars that are necessary to build and operate a renewable plant, as set forth in Table 1 in PGE's testimony, are not available to the small developer until *after* the PPA is signed and the PPA is used to close on financing for the project. Until that point, the small developer will need to rely on its own funding sources.

For example, PáTu is not a multi-national company that is traded on the New York Stock Exchange. During the development phase, I boot strapped the project with my personal funds

[7] PGE/100, Macfarlane-Morton/6.

from my 401k, a personal investment portfolio, and loans on my house. I did not have any more funds available. I paid over $350,000 for legal fees alone to structure the financing that enabled me to go forward with construction. That occurred prior to when the financing closed. Without a PPA, there would have been no financing. How much more would have I had to spend on legal fees to negotiate against the internal legal resources of PGE to obtain a PPA? How much more would I have had to invest in economic consultants to vette the utility's economic model, such as Aurora, or in attorney fees to challenge the utility's calculations at the OPUC if the rates offered were unfairly low? This simply would have been beyond my means and would have caused me not to develop PáTu. The utilities overlook the fact that the entire development is very speculative prior to PPA execution and is financed solely by the developer's funds. Unlike IOU's who develop projects - my development expenses are 100% at risk personally until the project PPA is executed and financing is closed. If PáTu was not financed, I would have lost everything and I would have not been able to go back to the OPUC to request a rate increase from my customers.

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

Q. Do you believe that it is easy to "disaggregate" a wind or solar project under the existing criteria in Oregon?

A. No. There is a five mile separation rule. There is little risk of the same type of disaggregation that occurred in Idaho where there was only a one-mile separation rule and wind QFs of up to 10 average monthly MW could obtain published rates. Having a 100 MW wind farm comprised of four or five 20-30 MW projects separated by one mile, as allowed previously in Idaho, is far easier than having a 100 MW project comprised of ten projects sized at 10 MW and separated by five miles, as currently required in Oregon. After pointing to several disaggregated Idaho QFs, Idaho Power's witness admits that the problem is mitigated in Oregon, where he states in footnote 54 of his testimony:

> Idaho does not have a dissaggregation rule similar to Oregon's. Therefore, it is arguably easier for QF developers in Idaho to chop up a 100 MW project into smaller sizes to take advantage of standard avoided cost rates. However, a not insignificant advantage of Idaho Power's request here is that if the eligibility cap is lowered, disaggregation will cease to be a problem.[8]

Q. PacifiCorp recommended eliminating the passive investor exception to the ownership criteria, but allowing for an additional exception for community projects.[9] What is your response?

A. I do not see a problem with the same passive investor being involved with two projects within five miles of each other. A passive investor can be a critical component of the investment, but they do not have managerial control over the project. Under IRS rules, a passive investor is essentially an investor with passive income from other activities which allows the passive investor to take advantage of tax benefits and accelerated depreciation. Without the passive investor, a small project may not have sufficient tax liabilities to take advantage of tax credits, tax grants, and accelerated depreciation. Additionally, larger institutional lenders are less willing to lend to small projects. Thus, with smaller projects with limited resources, a passive investor can be critical.

In fact, a recent paper published by the Lawrence Berkley National Laboratory on various

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[8] Idaho Power/200, Stokes/62 n.54.
[9] PacifiCorp/200, Griswold/24-25.

tax benefits stated, "if community wind is going to penetrate the broader wind market to any significant degree going forward, it may need to increasingly look to passive investors to finance that expansion."[10] Additionally, a study conducted on community projects prepared for the Energy Trust of Oregon concluded that one of the most effective financing models for a community renewable project is "a 'flip' structure, whereby a tax-motivated corporate investor passively owns most of the project for the first 10 years, and then 'flips' the ownership of the project to the local investor(s) thereafter."[11] The report also discusses the possibility of passive ownership in a project by several different farmers, who would likely have passive income from renting farmland.[12] It states that the "multiple local owner" and "flip" structures "are the most interesting from a community wind perspective, since they enable local individuals to participate in the ownership of a commercial wind project without undue capital outlay."[13]

Q. How would eliminating the passive investor option impact community renewable developers?

A. Based upon my experience, there are only few passive investors that would be interested in participating in a small project under 10 MW. PacifiCorp's recommendation would essentially make it nearly impossible to build two projects within five miles of each other in the State of Oregon. At a minimum, it would drastically limit the financing options for small projects near other small projects by eliminating the use of the few available passive investors. Another way to look at this is to think of a passive investor as essentially a private bank – just another source

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[10] Mark Bolinger, *Revealing the Hidden Value that the Federal Investment Tax Credit and Treasury Cash Grant Provide To Community Wind Projects*, at iii (Lawrence Berkeley National Laboratory, 2010), available online at http://eetd.lbl.gov/ea/ems/reports/lbnl-2909e.pdf (last accessed March 16, 2013).

[11] Mark Bolinger, Ryan Wiser, Tom Wind, Dan Juhl, and Robert Grace, *A Comparative Analysis of Community Wind Power Development Options in Oregon* at 12 (Prepared for the Energy Trust of Oregon, 2004), available online at http://www.oregon.gov/energy/RENEW/Wind/docs/CommunityWindReportLBLforETO.pdf (last accessed March 16, 2013).

[12] *Id.*

[13] *Id.*

of project capital and financing. Eliminating the passive investor exception is the same as eliminating the ability of small, community renewable energy projects to use private banks.

If the criteria are going to be revised, CREA strongly supports exceptions that will allow community-scale projects to continue development with standard rates. However, CREA is not in favor of a process that would require a prospective QF to petition the Commission to qualify for the exception, as proposed by PacifiCorp. Such a requirement would impose unworkable delays and hurdles that would frustrate a small developer's efforts for the reasons I have discussed above.

Q. Does CREA have a position on proposed revisions to the currently used definition of a single project in Oregon?

A. I would like to clarify that CREA is not in favor of disaggregation, and is open to reasonable proposals parties may make to the current Oregon criteria in an effort to render disaggregation for published rates more difficult in Oregon. CREA intends to review proposals from other parties and respond in reply.

Issue 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"?

Q. Do you believe that certain resource types should be restricted in their access to standard avoided cost rates?

A. No. Lowering the eligibility cap is a sledge hammer approach to a very limited problem. I do not think the evidence presented supports a major scaling back of Oregon QF policies by lowering the eligibility cap to 100 kW for wind and solar QFs.

Issue 5. D. Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?

Q. Does CREA have a position on this issue at this time?

A. Consistent with Order No. 11-505, the Commission should state that QFs electing the renewable rates retain their RECs during the sufficiency period and may dispose of them however they choose.

V. Issue 6: Contracting Issues (B., E., AND I.).

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

Q. Do you have any comments on the issue of when a legally enforceable obligation is incurred?

A. CREA will address legal issues surrounding this issue in legal briefing. I will only comment on issues relevant to the policy implications.

Q. Do you have any personal experience with this issue?

A. Yes, I do have experience with this issue. As I mentioned previously during the finance development stage of the PáTu I was forced to confront this issue due to a change in PGE's standard rates that were in effect during my development efforts. The rate change was a significant reduction from 2007 tariff rate that I had based all my financial projections for financing discussions with the banks. The change in this tariff structure caused my main potential lender at the time to discontinue discussions, and I was set back at least 6 months in development time – which could have been fatal. With small projects, there are so many moving pieces that when one piece such as financing falls out of the puzzle the whole project can be jeopardized.

Q. Do you have any general policy recommendations on this issue?

A. For small projects, the Commission should provide as much leeway to establish a legally enforceable obligation as allowed by the law. Most small QFs are not represented by counsel, and even those that are have very limited resources to spend on any attorney, especially when compared to the utility with which the QF is negotiating. The utility possesses all of the information. At a minimum, the Commission should explicitly require utilities to inform QFs at the time of first contact of the next likely time that the avoided cost rates will change. Then, at least the QF will know how long it has to lock in the avoided cost rates.

Q. Do you have a response to PacifiCorp's proposal that a legally enforceable obligation should be incurred when the QF approves the final draft power purchase agreement?[14]

A. This overlooks the fact that a disagreement prior to reaching a final draft contract could frustrate a QF's right to obligate itself to sell power and lock in the rates. For example, elsewhere in his testimony Mr. Griswold proposes to delay the entire contracting process to conduct studies on PacifiCorp's load pockets.[15] This could easily delay the QF's ability to obtain a final contract. The Commission should provide the QF with the right to obligate itself without necessarily requiring the QF to obtain a final draft contract from the utility.

Q. How would you implement that right?

A. I believe that the OPUC could follow the model developed by the Federal Energy Regulatory Commission ("FERC") for resolving disputes regarding transmission service agreements. When FERC developed the Open Access Transmission Tariff ("OATT"), it

[14] PacifiCorp/200, Griswold/30.
[15] PacifiCorp/200, Griswold/12.

required a standard contract for interconnection or point-to-point transmission service but recognized there might be disputes regarding certain specific terms of the service and other specific items. If a dispute arises, the large generator interconnection procedures of the OATT therefore states that the transmission customer may request that the utility's proposed version of the interconnection agreement be filed with FERC unexecuted to allow for FERC to resolve the disputed terms.[16] The customer preserves his place in the queue while FERC resolves the dispute. This allows the transmission customer to quickly resolve the dispute without going through the lengthy and expensive process of filing and litigating a formal complaint.

If PacifiCorp's proposal for a LEO formation is adopted, the OPUC should likewise provide the QF with a reasonable opportunity to lock in the rates by progressing through the process to a point of disagreement and then requesting that the utility's proposed contract be filed with the Commission for resolution of the disputed issue.

Q. PGE proposes that a LEO may not be formed more than one-year prior to delivering power.[17] Do think that is reasonable?

A. No. The PáTu project took 5 years of hard work to begin commercial generation. I could not commence major construction until the PPA was signed and the project was financed. For many projects, the construction process will take more than a year. As PGE's witnesses note, in the case of PáTu, it took less than a year. That was because I had been in discussions with several different banks for five years prior to when the PPA was signed, which reduced the time to close on the financing with the final lenders. This will not always be the case, however. Additionally, at the time I executed my contract in 2010 I was very lucky to be able to obtain

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16 *Standardization of Generator Interconnection Agreements and Procedures* ("*Order No. 2003*"),104 FERC ¶ 61,103, ¶ 240 (2003),

17 PGE/100, Macfarlane-Morton/23.

turbines from a project that had canceled their turbine contract, which vastly sped up the delivery process. Under normal circumstances, it could take over a year to obtain the turbines after signing the turbine contract, particularly at times when the turbines are in higher demand. PGE's proposal would effectively require many (or even most) projects to begin construction prior to obtaining financing. This is not possible for small projects.

Issue 6. E. How should contracts address mechanical availability?

Q. Could you provide background on the mechanical availability guarantee ("MAG") issue?

A. My understanding is that the MAG is intended to provide the utility with assurance that the QF will make its best efforts to keep the project available to produce electricity whenever the motive force (wind or otherwise) is available. To a certain extent, I question the need for such a provision in a PPA where the generator is only paid for electricity delivered to the utility. As an operator of a wind project, I have every incentive to make the project available as many hours as possible. The Commission should therefore ensure that this "guarantee" is not utilized as a penalty to the QF, or as a mechanism for the utility to evade its mandatory purchase obligation.

Q. What are the typical components of a MAG?

A. Typically in the wind turbine industry a MAG allows for a minimum of two points. One is a carve out of specific amounts of time for the manufacturer's required service or exclusions for the time required to maintain the turbine per the manufactures recommendations. And secondly is a remedy for failure to meet a MAG target. For example, if the project does not meet the target for one year there could be a remedy to improve the project performance that is agreed to by the parties. Remedies could be increasing the amount of spare parts on site or even changing maintenance providers – but there should be an agreed process to remedy the problem.

Q. Has the Commission addressed this issue in the past?

A. Yes. The Commission addressed this issue in UM 1129. The Commission first approved an annual minimum delivery obligation in QF standard contracts.[18] This provision requires that the QF warrant its minimum delivery to the utility. However, the Commission expressly noted that the minimum delivery provision had an inherent cure for failure to meet the delivery obligation in a single year. Thus, the QF should not have its contract terminated for failure to achieve the minimum delivery.

Concerns were raised that for intermittent QFs a minimum delivery obligation could unjustifiably result in penalizing the QF for a lack of motive force, which can change from year to year and is not something the QF can control or easily predict. In response, the Commission approved use of a MAG for intermittent QFs in lieu of the minimum delivery obligation.[19] It is important to note the MAG was originally intended to *lessen* the burden on intermittent QFs, not to impose a more difficult requirement upon them.

Q. How did the Commission describe the MAG?

A. In describing its understanding of the MAG, the OPUC stated, "Inadequate or excessive wind, force majeure and *scheduled maintenance* are examples of events that are deducted from the amount of time that the facility could have produced energy."[20] The OPUC also stated that the MAG "operates to affect the dollar payment to the QF, to the extent the QF does not meet its contractual availability commitment," which indicates MAG defaults would be cured with

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[18] OPUC Order No. 06-538 at 28-29.
[19] OPUC Order No. 07-360 at 32-34.
[20] *Id.* at 32 (emphasis added).

liquidated damages, rather than termination of the contract.[21]

Q. Do you have concerns with any of the MAG provisions filed by utilities after the Commission's directives in UM 1129?

A. Yes. PGE filed a MAG that is way out of line with industry norms and the Commission's directive on the matter. The MAG terms in PGE's current standard contract, initially filed as Advice No. 07-27, are attached to my testimony as CREA/102. PGE's current provision provides no carve out for the manufacturer recommended turbine maintenance. Also, because it is poorly drafted, PGE could attempt to construe it to require simultaneous availability of all six of the wind turbines during 95% of the hours in contract years two through twenty. In other words if one turbine is down for an unexpected outage or maintenance, PGE could try to read its standard PPA to determine that the entire plant is "unavailable" and thus not contributing to the 95% requirement. On top of that, PGE's MAG provides no expressly stated cure for any violation of the MAG requirement, and PGE has stated in discovery that it believes it possesses the right to terminate a PPA if a wind QF fails to hit this 95% guarantee in any single year.

I have explored the possibility of hiring an outside firm to warrant the availability guarantee contained in the PáTu PPA. However, as Dave Luck, Director of Business Development for EDF Renewables, one of the largest Operations and Maintenance providers to the renewable energy industry, told me:

> I am not aware of any turbine manufacturer, or 3rd party O&M provider, that would take on an Availability Warranty on a project with 6 turbines (unless the impacts for failure to meet the target availability were token in nature). With a project of this size, the risk exists of missing the target even with very reliable

[21] *Id.* at 34.

turbines and high quality O&M service. A typical target availability for a larger project (say 100 MW) would be 97% - and this would be after taking reasonable time out of the equation for Scheduled Maintenance [redacted]): The 3% (from the 100% possible) would be attributed to normal Unscheduled Maintenance (from fault resets, to component replacement). Your 95% MAG would leave you 2%, in this example, for significant or atypical outages – and that equates to a single event of 43.8 days on a single turbine. Even with an extreme inventory of spare parts, things like time required to mobilize a crane would make this a precarious situation.

I have included the entire correspondence from Mr. Luck as exhibit CREA/103, and it discusses other issues relevant to the MAG. This demonstrates that it is more risky to have a MAG at a small project with few turbines. A significant, unplanned mechanical problem causing a single turbine to go out of service for an extended period of time at a small plant will result in a larger percentage of overall unavailability at the entire plant than a similar event for a single turbine at a much larger plant.

Q. As an owner and operator of a wind project operating with PGE's MAG, what concerns do you have?

A. As the owner of a small wind project, I am very concerned with the onerous terms of the current PPA that I have been required to use. Not only is there no exclusion for planned and required maintenance, there is no expressly stated ability to put in place an agreed remedy if there is a problem. Also as Dave Luck pointed out – having a MAG for only 6 turbines is extremely risky. There may be years that go by in which I have no issues but there may be a year in which I have a gearbox problem. Problems with one gearbox easily could cause me to fall below my MAG objective. It is well known in the industry that gearbox problems increase with the life of the gearbox. Even though I have employed a first class maintenance provider, maintain spare parts on the site, and use Condition Based Monitoring to establish predictive maintenance procedures – this may not be sufficient in the latter years of my PPA.

Q. Could you explain PacifiCorp's MAG that it filed in compliance with UM 1129 orders?

A. PacifiCorp's Oregon QF MAG developed under the same OPUC orders applicable to PGE's MAG is attached as CREA/104.[22] PacifiCorp's provision provides that "Downtime Hours" do not include: (i) an event of Force Majeure; (ii) a default by PacifiCorp; (iii) Lack of Motive Force at times when the Facility would otherwise be available (including the normal amount of time required by the generating equipment to resume operations following a Lack of Motive Force); or (iv) outages scheduled at least 90 days in advance with PacifiCorp's written consent, up to 240 hours per unit per year. PacifiCorp's MAG also only requires 87.5% annual availability. If the QF fails to achieve the MAG, PacifiCorp's provision states the QF may cure by compensating the utility through liquidated damages for the amount of replacement energy required due to the QF's failure to be available. This is much more reasonable and in keeping with the Commission's directives.

Q. Why is it important that the term of PGE's standard contract be reasonable?

A. PGE's MAG clause is a barrier to eligible QFs' access to standard rates, otherwise available for all QFs up to Oregon's eligibility cap of 10 MW. The Commission has recently determined, "If a QF believes the substantive terms of a standard contract would be commercially unworkable for its facilities, then that QF – despite being qualified to take a

[22] *See* PacifiCorp Advice No. 08-013.

standard contract – should negotiate a nonstandard contract."[23] It is clear that because PGE's MAG is commercially unworkable for *any* small wind project, all wind QFs must negotiate a non-standard contract with negotiated, non-standard rates. This defeats federal and state policies to provide standard rates to small QFs.

Based on discovery in this docket, only one wind QF has signed PGE's standard contract – PáTu. I am the operator of that project and attempted to negotiate a change to the MAG with PGE. PGE refused to modify the MAG prior to execution and has insisted that its MAG is fair ever since. No other wind QFs have signed PGE's standard contract with its MAG. Coincidentally, based on the same information, at least sixteen wind QFs have signed standard PPAs with PacifiCorp.

Q. Was the MAG an issue in obtaining financing for the PáTu project?

A. Yes. CoBank ACB was my source for project financing. CoBank made a decision that they would only provide construction finance, not long-term finance, because of the MAG requirement in the PPA. They decided that the MAG in the PGE PPA was not practical for a small project. This put me in a very difficult position without the ability to access long term finance. The PGE MAG essentially stopped my ability to obtain commercial long term financing from traditional industry sources. Fortunately, through the Oregon Department of Energy's Small Energy Loan Program, I was able to obtain long term financing.

Q. Has PGE proposed to change its MAG in this case?

A. PGE has made very modest proposals for change, but I still believe even with PGE's proposed changes that PGE's MAG would be out of line with industry norms. PGE still proposes to retain the 95% guarantee. However, PGE proposes to clarify that it believes

[23] OPUC Order No. 12-316 at 5.

availability should be averaged across all turbines, rather than construing the clause to require simultaneous availability, and PGE proposes 100 hours per year of scheduled maintenance. While these are improvements to the entirely onerous clause in the PáTu contract, it does not go far enough. Both PacifiCorp and Idaho Power agree that failure to achieve a MAG in a single year should not result in termination of the agreement, but rather should be addressed with liquidated damages. This is consistent with the Commission's understanding in UM 1129. Additionally, PacifiCorp proposes 90% annual availability, and Idaho Power proposes 85% monthly availability. Either of these limits is reasonable.

Q: PGE cited a publication by Stoel Rives titled "The Law of the Wind: A Guide to Business and Legal Issues." Do you believe that this publication cited by PGE supports PGE's position?

A. No. PGE asserted that this Stoel Rives publication establishes that "Typical mechanical availability guarantees provide for a guarantee of a mechanical availability percentage in each contract year of 95 percent."[24] However, PGE appears to have selectively quoted the chapter of the publication that discusses the guarantees from the equipment supplier to the project owner, not the provisions typically found in a PPA. Notably, PGE has provided no actual PPAs (other than its own standard contract) to support PGE's position that 95% availability with no opportunity for cure is reasonable.

Q. Were you able to locate the most relevant portion of the Stoel Rives' publication and its statement of what is typically contained in a MAG in a PPA?

A. Yes. I have provided excerpts of the publication containing the portion PGE relied upon and the more relevant portion discussing PPA terms as CREA/105. The chapter of the

[24] PGE/200, Macfarlane-Bettis/4.

publication addressing terms in PPAs contains a significantly different explanation of a typical MAG from the description that PGE relied upon. The Stoel Rives publication states:

> **B. Availability Guarantees.** The owner of the wind project is usually more willing to offer the purchaser a mechanical-availability guarantee than to offer an output guarantee. Such an availability guarantee requires the wind turbines in the project to be available a certain percentage of the time, *after excluding hours lost to force majeure and a certain amount of scheduled maintenance. Mechanical-availability percentages usually range from 90 percent to 95 percent, but they may decline over the life of the project or even disappear altogether during the final years of the PPA term to reflect wear and tear on the turbines.*[25]

Additionally, although PGE relied upon the description of a MAG in an agreement with a turbine manufacturer, the chapter on PPA terms goes on to state:

> Wind turbine manufacturers typically provide availability warranties that support the project owner's mechanical-availability guarantees for the first few years of the project. However, such warranties generally last only five years or less, and the seller is usually on its own if it chooses to give a mechanical-availability guarantee that covers the period after the manufacturer's warranty expires.[26]

The publication also discusses the common use of liquidated damages to address an availability shortfall. It further discusses the limited possibility of termination of the PPA with the following passage:

> **Termination Rights.** To protect against *chronic problems* at an unreliable wind

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[25] CREA/105, Hilderbrand/2 (emphasis added). The full version of the most recent Sixth Edition of this publication is available online at http://www.stoel.com/webfiles/LawOfWind.pdf.
[26] *Id.*

plant, the PPA may allow the buyer to terminate the PPA if the output or mechanical availability of the project is below a stated minimum *for a certain number of years.*[27]

Q. What conclusions can be drawn from this publication?

A. This publication appears to be targeted towards larger wind farms, and its estimates of typical availability percentages would likely be too high for a small plant. Even so, this publication still does not support PGE's position that a 95% availability guarantee throughout the entire life of the contract is reasonable, or that failure to achieve the 95% availability *in any single contract year* should result in termination of the PPA. I would not necessarily suggest that a publication on a law firm's website is the controlling authority on the topic without having the authors available to provide further explanation. However, I find it telling that PGE relies on a publication that in fact supports CREA's position that PGE's existing and proposed MAGs are unreasonable and out of line with industry norms.

Q. Do you have an opinion on the appropriate amount of scheduled maintenance carve out and the appropriate availability guarantee level?

A. First of all, the Commission should expressly state that the utility cannot terminate a PPA for failure to meet the annual availability guarantee in a single year. Liquidated damages is the appropriate way for the QF to make the utility whole for the output that it would otherwise have delivered to the utility if the rate in the PPA is lower than the cost of replacement power. Otherwise, the MAG can become a tool for the utility to evade its mandatory purchase obligation, rather than to encourage the QF to make its facility available. I believe that if the annual availability requirement is reasonably set at 90%, that PacifiCorp's proposal for 60 hours

[27] CREA/105, Hilderbrand/3 (emphasis added).

of scheduled maintenance per turbine is reasonable. I do not believe that PGE's proposed changes go far enough because 95% is simply not a reasonable availability requirement for a small project where a mishap at a single turbine can cause significant unexcused downtime at no fault of the project. While Idaho Power also proposes to allow for scheduled maintenance, its proposal does not include a set number of hours per year. Generally, less ambiguity is better when trying to finance a plant.

The Commission should adopt a uniform standard and contract language for all three utilities to avoid the risk of any single utility inadvertently or intentionally deviating from the intent of the Commission's order. On the whole, I believe that PacifiCorp's proposed revisions to its MAG are reasonable and should be adopted for all three utilities.

Q. You mentioned that your PáTu wind farm is the only PPA that has been executed with PGE's current MAG. Do you have any suggestions for how the Commission should handle that single PPA?

A. My PPA contains an onerous clause that is inconsistent with the Commission's directives on the matter. I believe that the Commission should instruct PGE to agree to renegotiate the clause to be more reasonable and in line with the Commission's orders in effect at the time of execution of my contract. While I understand the Commission is reluctant to order reformation of the executed contract prior to the time when PGE may attempt to enforce this onerous clause, the Commission should at least inform PGE that it does not believe the clause is reasonable. The Commission could also inform PGE that the Commission would not penalize PGE in rate recovery if PGE renegotiated a more reasonable clause in this PPA, to remove any legitimate basis PGE may have to refuse to correct this onerous and poorly drafted clause in the PáTu PPA.

Issue 6. I. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?

Q. Do you have an opinion on the appropriate contract term?

A. The current term of 15 years with fixed rate is the absolute minimum that can be financed by a 10 MW project. Preferably, QFs would have the option to obtain fixed rates for at least 20 years. I believe it would be reasonable for the Commission to extend the fixed rate term to 20 years.

Q. PGE proposed that QFs renewing a contract should only have access to fixed rates for five years. Do you agree?

A. As I have explained previously – renewable energy projects are very long term investments but equipment needs to be upgraded as the equipment ages and new technologies are made available. In fact the IOU's expect these upgrades to take place through their MAG requirements. Let me be clear – I cannot see a possibility of obtaining financing for major turbine upgrades with only a 5-year fixed-rate tariff. If PGE's proposal is accepted I will have no other option but to sell the project because I will not be able to obtain financing for continued operations.

Q. Does this conclude your testimony?

A. Yes.

Oregon Public Utility Commission

Docket No. UM 1129, Order

May. 13, 2005

ORDER NO. 05-584

ENTERED 05/13/05

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

In the Matter of	)	
	)	
PUBLIC UTILITY COMMISSION OF	)	
OREGON	)	ORDER
	)	
Staff's Investigation Relating to Electric	)	
Utility Purchases from Qualifying Facilities.	)	

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities.	)))))))	ORDER

DISPOSITION: PURPA POLICIES ADOPTED

I. SUMMARY

In this order, we evaluate specific policies and procedures to determine whether Commission goals relating to the Public Utility Regulatory Policies Act (PURPA)[1] could be more effectively implemented and achieved. A basic purpose of PURPA is to provide a market for the electricity produced by small power producers and cogenerators. This Commission's goal has been to encourage the economically efficient development of these qualifying facilities (QFs), while protecting ratepayers by ensuring that utilities pay rates equal to that which they would have incurred in lieu of purchasing QF power.[2]

Our decisions in this proceeding are consistent with this goal, and apply primarily to standard contract rates, terms and conditions for QF power. These decisions include the following:

<u>Eligibility for and Term of Standard Contracts</u>

- Establishing a 10 MW standard contract eligibility threshold.

- Adopting the manufacturer's nameplate capacity for a QF project as the measure of eligibility for standard contracts.

- Establishing a maximum standard contract term of twenty years. Allowing a QF to select fixed pricing for the first fifteen years of

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[1] The United States Congress passed PURPA in 1978, as codifed in the United States Codes (USC) at *16 U.S.C. § 824a-3*.

[2] *See* Order No. 81-319 at 3.

the standard contract, but requiring the selection of a market pricing option for the last five years.

Calculation of Avoided Costs

- Requiring PacifiCorp and Portland General Electric (PGE) to use the historical methodology to calculate avoided costs rates when either utility is in a resource deficient position.

- Requiring PacifiCorp and PGE to use monthly on- and off-peak forward market prices, as of the utility's avoided cost filing, to calculate avoided costs when either utility is in a resource sufficient position.

- Allowing Idaho Power to use the surrogate avoided resource (SAR) methodology to calculate avoided rates, regardless of the utility's resource position.

- Requiring payment of full avoided costs pursuant to the appropriate methodology for all energy, whether intermittent or firm, that is delivered by a QF under a standard contract to a utility up to the nameplate rating of the project.

- Requiring payment for energy only for all energy delivered over the nameplate rating for a QF under standard contract.

Pricing

- Requiring utilities to offer three pricing options for standard QF contracts: (1) the Fixed Price Method; (2) the Deadband Method; and (3) the Gas Market Method. Requiring PGE to also offer its proposed Mid-C Index Rate Option.

Security, Construction Credit, Insurance and Indemnity Requirements

- Requiring all QFs to establish creditworthiness by making a set of representations and warranties that the QF has good credit, including that it is current on existing debt obligations and has not been a debtor in a bankruptcy proceeding within the preceding two years.

- If a QF cannot establish creditworthiness, requiring the QF to provide a reasonable amount of default security, as determined by the utility—but subject to Commission review—by one of the following means selected by a QF: senior lien, step-in rights, a cash escrow or a line of credit.

- In the event a QF defaults and the market prices of energy to replace the contracted for energy exceed the contract price, requiring that future payments to the QF after the default period ends must be commensurately reduced over a reasonable period of time to recoup costs incurred.

- Requiring that, if a utility is in a resource deficient position at the time a QF contract is signed and the QF project is not operational by the date specified in the contract, and market energy prices to replace the contracted for energy exceed the contract price, future payments to the QF after the default period ends must be commensurately reduced over a reasonable period of time to recoup costs incurred.

- Requiring the incorporation of a mutual indemnity clause in contracts.

- Requiring all QFs with a design capacity above 200 kW to carry a reasonable amount of general liability insurance.

Repeal of PURPA

- Concluding that QF contracts do not terminate upon repeal of PURPA, unless termination of QF contracts is mandated by federal or state law.

We find that the evidence presented in this proceeding was largely inadequate to develop specific guidance regarding non-standard contracts, except on issues that were identified at the start of this proceeding as applying to non-standard contracts. We affirm, however, that it is our intent and goal to facilitate the development of QFs of all sizes. Consequently, in this order, we identify several issues pertaining to non-standard contracts that require further development in a second phase of this docket. These issues are in addition to issues that had been identified at the start of this proceeding as being properly addressed in a second phase, as well as issues applying to standard contracts that we also identify herein as appropriate for further development in a second phase.

The issues identified for the second phase include:

- Development of negotiation parameters and guidelines for non-standard QF contracts.

- In the event of the inability of a QF to establish creditworthiness, determination of an appropriate amount of default security to be required.

- Further exploration of how the calculation of avoided cost should reflect the nature and quality of QF energy.

- Further exploration of a Mechanical Availability Guarantee (MAG).

- Further exploration of market pricing options and alternatives to using nameplate capacity to determine the size of a QF project for standard contract eligibility purposes.

- Cap on amount of default losses that can be recouped, pursuant to future QF contract payment reductions.

- Liability insurance for QFs with a design capacity at or under 200 kW.

- Negotiation parameters and guidelines for "simultaneous sale and purchase" QF contract.

- Negotiating "net output sales" for non-standard contracts.

- Further exploration of Staff's role in the informal dispute resolution of QF contract disputes.

II. INTRODUCTION

A. PROCEDURAL BACKGROUND

On January 20, 2004, the Commission opened an investigation related to electric utility purchases from qualifying facilities (QFs). We opened the investigation due to concerns raised by industrial and rural developers and operators of QF projects about the availability of standard rates and the terms and conditions of contracts for purchases of electricity from QF projects.

On February 11, 2004, an initial prehearing conference was held and a partial procedural schedule was established. Pacific Power & Light, dba PacifiCorp (PacifiCorp), Portland General Electric Company (PGE) and Idaho Power Company (Idaho Power) (collectively "the electric utilities") filed Informational Filings to provide foundational information about the current state of their respective tariffs and contracts relating to qualifying facilities. A workshop to discuss the filings followed on March 23, 2004. On June 18, 2004, a second prehearing conference was held and a full procedural schedule was established. In addition, parties agreed to address six issues in the first phase of this investigation.[3] Other issues that had been identified by the Commission Staff (Staff) for potential consideration were left to be taken up in a subsequent phase of the proceeding or in a separate proceeding.[4]

On August 3, 2004, Staff and several Intervenors filed testimony. Intervenors fall into three general categories—the electric utilities, current and potential cogenerators and small power producers, and consumer representatives and public agencies concerned with state energy policies—and include the following entities: Ascentergy Corporation; Central Oregon Irrigation District; Columbia Energy Partners; the Fair Rate Coalition (FRC); J. R. Simplot Company (Simplot); Idaho Power; the Industrial Customers of Northwest Utilities (ICNU); Middlefork Irrigation District; PacifiCorp; PGE; the Oregon Department of Energy (ODOE); the Sherman County Court

[3] Parties addressed the following issues in this proceeding: (1) Contract length and price structure: What is the appropriate contract length which is consistent with the Federal PURPA law standards and which will balance the interests of the QF developers and the utility's customers? Current practice is a five-year term. What is the appropriate pricing structure (e.g., prices that vary by year, prices that are levelized over the contract term) and should the Commission specify that structure? Current practice varies by utility, size of customer, and date of agreement; (2) Size threshold for standard rates: What size facilities should be eligible for standard purchase rates and a standard power purchase agreement which is consistent with the Federal PURPA law standards and which will balance the interests of the QF developers and the utility's customers. The current threshold is one MW; (3) Utility tariff content: What prices, terms and conditions should be included in utility tariffs? How should the Commission ensure that all terms and conditions it approves in the avoided cost filings are publicly available? Current practice is to include only basic pricing, terms and conditions in the tariff for small qualifying facilities (1 MW or less). The other avoided cost information approved by the Commission is contained in the utility's filing; (4) Avoided cost calculation methods: What is the appropriate method for calculating avoided costs? Current practice is to use (a) the variable costs of operating existing generating facilities until projected supply deficits occur and (b) when new resources are needed, their estimated capacity and energy costs; (5) Applicability of Oregon PURPA administrative rules: Since federal PURPA still applies to all electric companies and the Commission is responsible for its implementation, what is the practical effect of the ORS 757.612 exemption for PGE and Pacific? The administrative rules need further review to differentiate the rules that implement federal PURPA from the rules that were specific to Oregon PURPA law; (6) Dispute mediation: What should be the Commission and staff roles in mediating or litigating PURPA-related disputes? Current practice is described above.

[4] Potential issues identified by Staff that were deferred until a subsequent phase or separate proceeding include the following: (1) Alternative forms of regulation: Do utilities have a financial incentive to discourage the development of qualifying facilities due to reduced sales? If so, should the Commission use other types of regulation (e.g., decoupling) to mitigate the disincentives; (2) Filing cycle for avoided cost studies and related tariffs: Currently the companies file avoided cost studies about every two years following IRP acknowledgement and they update standard purchase rates and contract terms accordingly. In addition, OAR 860-029-0080(4) requires electric utilities contracting to buy non-firm power from a qualifying facility to submit quarterly filings of avoided energy costs. PGE is the only Oregon investor-owned utility with such a contract. Even though the rule no longer applies to PGE, the company files, and staff reviews, quarterly avoided cost filings. Staff recommends consideration of this issue in the context of the Commission's review of Least-Cost Planning (Docket No. UM 1056); (3) Net metering: Net metering allows customers, in essence, to run their meter backwards and receive credit on the electric bill when their generation exceeds their use. Currently, eligibility is limited to customers with a generating capacity of 25 kW or less from certain types of resources. In the future, the Commission may want to consider raising this threshold; (4) Interconnection procedures and agreements: Staff is monitoring federal proceedings related to these issues. At a later date, staff plans to ask the Commission to open a proceeding to establish state interconnection standards; (5) Standby rates: The Commission addressed PGE's standby tariffs in Docket No. UE 158

(Sherman County); Symbiotics, LLC; and Weyerhaeuser Corporation. On September 17, 2004, the electric utilities filed rebuttal testimony. Supplemental rebuttal testimony was submitted on September 30, 2004. On October 14, 2004, Staff and Intervenors filed surrebuttal testimony. A hearing was conducted on October 27, 2004, and October 28, 2004. The parties filed opening briefs on December 23, 2004, and reply briefs on January 27, 2005. On February 7, 2005, oral argument was held.

B. HISTORICAL BACKGROUND

Sections 201 and 210 of PURPA encourage resource competition and the development of cogeneration and renewable energy technologies by non-utility power producers called "qualifying facilities" or "QFs."[5] PURPA requires the Federal Energy Regulatory Commission (FERC) to prescribe and periodically revise rules that "require electric utilities to offer to . . . purchase electric energy from [QFs]."[6] PURPA further specifies that the rates paid by utilities for electric energy purchased from QFs may not exceed "the incremental cost to the electric utility of alternative electric energy."[7] PURPA defines incremental costs as "the cost to the electric utility of the electric energy which, but for the purchases from such [QF], such utility would generate or purchase from another source."[8] PURPA also requires electric utilities to purchase power from QFs at rates that are just and reasonable to the utility's customers and in the public interest and that do not discriminate against QFs, but that are not more than avoided costs.[9]

FERC complied with its PURPA obligation by promulgating Title 18, Part 292 in the Code of Federal Regulations (CFR).[10] In so doing, FERC stated that "a basic purpose of section 210 of PURPA is to provide a market for the electricity generated by small power producers and cogenerators."[11] Regulations adopted by FERC seek to create this market by requiring utilities to purchase electricity from QFs at the utility's "full avoided costs" and to adopt non-discriminatory interconnection and back-up power policies and pricing. FERC's full avoided cost rule was unanimously upheld by the Supreme Court in 1983.[12]

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[5] A "qualifying facility" refers to a cogeneration facility or a small power production facility. OAR 860-029-0010(22). *See also* OAR 860-029-0010(25). PURPA defined two types of qualifying facilities: (1) a cogeneration facility that produces electric energy and steam or forms of useful energy (such as heat) that can be used for industrial, commercial, heating or cooling purposes. Cogenerators may be any size, so long as plant thermal output is at least five percent of total energy output. If fueled by oil or gas, the plant must meet certain efficiency criteria; and (2) A small power production facility that produces electric energy using biomass, waste or renewable resources as the primary energy source. Such facilities must have a nameplate capacity of 80 MW or less. In addition, at least three-fourths of the plant's energy must be derived from renewable resources or waste products.

[6] 16 U.S.C. § 824a-3(a).

[7] 16 U.S.C. § 824a-3(b).

[8] 16 U.S.C. § 824a-3(d).

[9] *Id.* § 824a-3(b)(1) and (2).

[10] 18 CFR §292.101 et seq.

[11] Federal Register, Vol. 45, No. 38, (February 25, 1980) (hereinafter, "Federal Register"), p. 12221.

[12] *Federal Energy Regulatory Commission v. American Electric Power Service Corporation*, 76 L. Ed. 2d 22, 34 (May 16, 1983).

PURPA also requires states to implement the promulgated FERC rules for investor-owned electric utilities.[13] Indeed, PURPA and FERC regulations delegate calculation of appropriate QF contract rates to individual state agencies. Oregon passed parallel state legislation (ORS 756.516 and ORS 758.500, et seq.). The Commission[14] first began developing rules implementing the federal and state requirements in 1980.[15]

In August of 1980, the Commission initiated rulemaking proceedings, Docket No. R 58, to establish QF policies. Order No. 80-568 solicited public input on identified issues and directed each electric utility to submit draft tariffs and other written materials details proposals for contracting with QFs. On May 6, 1981, the Commission entered Order No. 81-319 setting forth general policies and proposed rules for contracting with QFs. The intent of the order was:

> to provide maximum economic incentives for development of qualifying facilities while insuring that the costs of such development do not adversely impact utility ratepayers who ultimately pay these costs. The Commissioner will generally attempt to maintain this balance by requiring purchases of power from qualifying facilities at the purchasing utilities incremental generation and/or purchasing cost, thereby costing the ratepayers no more than the cost of the utility's own generation or wholesale purchases.[16]

The order established policies including: (1) rates for QF purchases would be at avoided costs; (2) standard rates would be available for QFs with a design capacity of 100 kW or less; (3) non-firm energy would be valued at the time of delivery; (4) firm energy would be valued, at the option of the QF, at the time a legal obligation is incurred to purchase the energy or at the time of delivery; (5) levelized payments would be allowed; (6) non-performance penalties were disallowed; (7) utilities could maintain a 10 percent reserve or require performance bonds as protection against non-performance; and (8) interconnection costs could be spread over a reasonable length of time, with one-half the contract term being deemed as reasonable.

On October 29, 1981, the Commission entered Order No. 81-755 adopting rules for contracting with QFs. The rules set forth factors to be considered in establishing avoided costs and required utilities to file avoided cost data on an annual and quarterly basis, subject to Commission review. QF rates were subject to a standard of review that required the rates to be just and reasonable to ratepayers and in the public interest.

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[13] *Id.*

[14] At the time, there was only one Commissioner and the agency was typically referred to as "the Commissioner." For ease and clarity in this order, however, the term, "the Commission" will be used, even when referencing actions taken by the Commissioner, except in quotes from prior orders.

[15] *See* OAR 860-029-0001 et seq, (2004). Pursuant to ORS 757.612(4), OAR 860-029-0001 exempts public utilities that satisfy the public purpose obligations set forth under ORS 757.612 from the Oregon PURPA laws.

[16] Order No. 81-319 at 3.

On September 12, 1984, the Commission entered Order No. 84-720 which modified certain QF contracting policies, including as follows: (1) required utilities to use a 35-year time period to project avoided costs rather than the 20-year statutory minimum; (2) required inclusion of a capacity payment in avoided cost calculations; (3) required seasonally differentiated short-term avoided energy costs; and (4) required standard contracts for QFs under 100 kW to be based on a projected 20-year contract life.

Less than two weeks later, the Commission entered Order No. 84-742, which addressed several significant policy issues regarding QF contracts. One issue was declining avoided cost rates resulting from an energy surplus in the region and consequent concerns that QF development would be hindered. A particular concern existed for QFs with a nameplate rating of 100 kW or less that typically did not have fixed-price agreements but rates that fluctuated with avoided costs. The Commission rejected a proposal to implement rates in excess of avoided costs. In rejecting this request, the Commission noted:

> Higher rates would make more projects feasible. However, the Commissioner has another goal to consider. That goal is to obtain service for ratepayers at reasonable rates. With upward pressure on utility rates coming from a variety of sources, the Commissioner is reluctant to impose higher costs on ratepayers.
>
> The Commissioner believes that the best balance between the two goals is to set rates equal to avoided costs. In periods of surplus, such as now, fewer projects are needed. When deficits are projected, avoided costs will rise and opportunities for profitable facility development will expand. Therefore, as a general policy, the Commissioner endorses adherence to avoided costs as the best pricing method.[17]

Instead, the Commission approved QFs with a nameplate rating of 100 kW or less having the option to enter into a long-term contract based on avoided costs in effect at the time the QF signed its original power delivery agreement or a short-term (five year) contract at the standard rate in effect the preceding year, escalated at four percent a year.

In Order No. 84-742, the Commission also addressed the issue of inequity in bargaining power between small QFs and utilities. Rather than adopting a proposal to establish the terms of QF contracts in a rulemaking, the Commission encouraged greater use of the Commission's dispute resolution services as, "the most effective way to equalize bargaining power."[18] A party could also file a petition with the Commission

[17] Order No. 84-742 at 3.
[18] *Id.* at 5.

requesting establishment of the terms of a QF contract. In Order No. 84-742, the Commission also addressed utility recovery of QF contract costs, stating:

> Since utilities are required by law to make purchases, and the Commissioner reviews the contracts, the chances of legitimate expenditures being disallowed are very small. The public interest will be better served by retaining the ability to examine the legitimacy of all utility expenditures. The Commissioner believes that the risk of non-recovery is a very small one that should be borne by the utility.[19]

In January 1985, the Commission entered Order No. 85-010, which addressed the issue of levelization. Partial levelization of the fixed cost (*i.e.,* capital costs) of the capacity portion of avoided costs was approved as a continuing policy. In the order, the Commission rejected levelization of variable costs and fixed operation and maintenance costs. The Commission approved a proposal by Staff to begin levelized payments in the year the utility was scheduled to begin development of a new resource. Prior to that year, QFs would receive nonlevelized payments. The Commission rejected a recommendation that QFs be allowed to "lock in" avoided costs during negotiations on other aspects of a contract. The Commission also indicated that a rule would be developed to address the Commission's role in dispute resolution.

Orders issued in 1986 and 1987 broadened, then narrowed, the Commission's dispute resolution role. Order No. 86-488 set forth rules establishing an informal assistance role, at the request of either a QF developer or an electric utility, for Staff to play in resolving disputes arising during contract negotiation. Order No. 87-1154 cancelled these rules and that role, however. Although a docket was opened to continue investigation into cogeneration, no order was ever entered in the proceeding. Instead, the Commission made a report to the Legislature.

In the 1988 report to the Oregon Legislature, the Commission stated its policy regarding PURPA implementation:

> It is the policy of the Oregon Public Utility Commission that federal and state laws and regulations will be carried out in a manner that encourages the economically efficient development of qualifying facilities in Oregon. It is the goal of the Commission to ensure desired qualifying facility development through stable and predictable actions by the Commission, accurate price signals, and full information to developers and the public regarding power sales requirements.[20]

[19] *Id.*

[20] Order No. 91-1605, entered on November 26, 1991, in Docket No. AR 246, implemented the change.

In addition to discussing the Commission's general policies, the report addressed numerous specific policy matters, including the methodology to determine avoided costs and issues regarding the QF contracting process. The report made several recommendations, including the following: (1) a proxy plant should not be used to determine avoided costs; (2) standard contracts for QFs sized at 1 megawatt (MW) or less warranted further investigation; (3) Staff should not participate in informal dispute resolution in order to preserve objectivity in ratemaking proceedings; and (4) QF contracts should not be pre-approved for cost recovery.

In Order No. 91-1383, entered in a docket primarily addressing competitive bidding policies, the Commission addressed issues affecting QFs in both PURPA and competitive bidding contracts. In the order, the Commission indicated that, due to the transaction costs in negotiating a QF contract, the capacity size limit to be eligible for standard rates should be raised from 100 kilowatts of nameplate capacity to 1000 kW or less. The order specified that a rulemaking would be opened to change the capacity limitation.[21] With regard to the length of contracts, the Commission indicated, "[t]he length of the contract a utility and a winning project sponsor agree to should result from their negotiations rather than from a Commission fiat."[22] The Commission then adopted the following three criteria for evaluating the prudency of contracts with terms of 20 years or more: (1) Whether there is a high probability that the resource will be operable well beyond 20 years; (2) Whether the developer could obtain financing for the resource for contract lengths of less than 20 years; and (3) Whether the resource's physical and cost characteristics make contract terms of more than 20 years advantageous to all parties.

Five years later, however, as the energy industry was undergoing tremendous change and evolving towards more competitive markets, the Commission limited the terms of QF contracts to five years. On October 30, 1996, PGE filed Advice No. 96-21, which proposed five-year term limits on QF contracts. In support of the term limit, PGE represented that the majority of long term power purchase contracts being negotiated in the energy market at the time were for periods of three to five years and that a QF contract longer than five years posed significant risk to PGE and its ratepayers. Staff supported the proposal, noting "[g]iven the continued movement toward a competitive marketplace for electricity and the prevalence of wholesale transactions for terms of five years or less," it is difficult to justify long-term QF contracts.[23] At the December 17, 1996 Public Meeting, the Commission adopted PGE's filing, thereby establishing a five-year contract length standard beginning in 1997.

C. SCOPE AND FRAMEWORK OF THIS ORDER

Before turning to the parties' arguments, we must clarify the scope and framework of this Order. As discussed above, we opened this proceeding to generally

[21] Order No. 91-1383 at 15.
[22] *Id.* at 16.
[23] Staff Report for December 17, 1996 Public Meeting, at 4.

investigate issues related to energy purchases from QFs by electric utilities. When the investigation was opened, Staff identified a number of general issues to be discussed. Ultimately, six of these general issues were designated to be taken up in this proceeding.[24]

Parties devoted significant attention in this proceeding to discussion of general PURPA requirements and the responsibilities of states to implement PURPA. We do not view the purpose of this docket to be a review of the Commission's general PURPA goals and policies, however. As discussed above, this Commission has consistently interpreted its PURPA mandate to be the adoption of policies and rules that promote QF development, using among other tactics, accurate price signals and full information to developers, while ensuring that utilities pay no more than avoided costs.

We view the purpose of this investigation to be an evaluation of specific rules and policies to determine whether the general PURPA goals that this Commission has long articulated could be more effectively implemented and achieved. This purpose is consistent with the scope of the proceeding agreed to by the parties. Staff requested that this investigation be opened in order to address the lack of recent QF development and recommended that we address six specific issues in the initial phase of this proceeding. Parties eventually agreed to this scope.

We reject PacifiCorp's arguments that the proceeding's scope is restricted solely to the review and revision of standard contract terms and conditions and does not encompass issues associated with the negotiation of non-standard contracts. We agree with Staff that the proceeding's scope is not limited to standard contracts, at least with regard to five of the six issues addressed.[25] Unfortunately, however, the parties presented little evidence regarding parameters and negotiating guidelines for non-standard contract terms and conditions. Although much of the evidence introduced in this proceeding could have potentially been used to support arguments for adopting more detailed negotiation guidelines and parameters for non-standard contracts, as Weyerhaeuser argues, the evidence was neither framed nor addressed in this manner. Consequently, as we later discuss in more detail, we conclude that the record in this proceeding does not support the adoption of detailed negotiation guidelines and parameters for non-standard contracts at this time.

Nonetheless, our intent with regard to implementation of PURPA remains the same as first articulated in 1981. We seek to provide maximum incentives for the development of QFs of *all* sizes, while ensuring that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs. We are persuaded that significant barriers exist to the negotiation of non-standard contracts and that the detailed negotiation parameters and guidelines, as well as other measures, may overcome these barriers. Consequently, we deem it appropriate to address parameters and guidelines for the negotiation of non-standard contracts in a second phase of this proceeding.

[24] *See supra* note 3.

[25] Issue number two, which addresses eligibility for standard contracts, was necessarily focused on standard contracts, although resolution of the issue has ramifications for non-standard contracts.

In keeping with how issues were framed and the nature of evidence introduced in this proceeding, the bulk of policy decisions made in this order exclusively apply to standard contracts. Certain issues, however, have consequences for the negotiation of non-standard contracts. For example, decisions regarding the calculation of avoided costs will have ramifications for the negotiation of non-standard contracts since these avoided costs are the starting point for negotiations of such contracts. Other issues were general in nature from the start. For example, dispute resolution procedures and the applicability of PURPA administrative rules are issues that have general applicability to all QF contracts and negotiations. A number of sub-issues were also identified in this proceeding having general consequences for both standard and non-standard QF contracts alike.

To be clear about the applicability of our decisions to standard contracts versus non-standard contracts, we indicate, where warranted, how such decisions affect negotiation of non-standard contracts. We also identify when it is appropriate to take an issue up, as it relates to either standard or non-standard contracts, or both, in a second phase of this proceeding.

III. STANDARD CONTRACT TERMS AND CONDITIONS

The term, "standard contract," has been widely used by parties since passage of the federal PURPA law. The term is used to describe a standard set of rates, terms and conditions that govern a utility's purchase of electrical power from QFs at avoided cost. Standard contracts are made available to a defined class of QFs that are deemed eligible under federal or state law to receive standard rates.

Parties raised a range of issues regarding standard contracts in this proceeding, including calculation of avoided costs, standard contract pricing and the appropriate length of a standard contract. A particularly contentious issue in this proceeding concerned eligibility to receive a standard contract. We address each issue and sub-issue raised during this proceeding, making policy decisions on many of the issues, and deferring or dismissing other issues as appropriate.

A. SIZE ELIGIBILITY TO RECEIVE STANDARD CONTRACTS

1. Overview

Most parties propose continuing to divide QFs into two categories: QFs that are eligible to sell power pursuant to a standard contract, and QFs that are not eligible for a standard contract. Standard contracts have pre-established rates, terms and conditions that an eligible QF can elect without any negotiation with the purchasing utility. If a QF is not eligible for a standard contract, a utility is still obligated to purchase a QF's net output at the utility's avoided cost, but the QF must negotiate the rates, terms and conditions of a power purchase contract with the purchasing utility.

The primary disagreement among the parties is the appropriate size threshold that should divide the two categories. The current threshold is 1 MW. Thus, QFs sized at or under 1 MW in size are eligible to obtain standard contract terms and conditions, while QFs over 1 MW are required to negotiate individual contracts with electric utilities.

2. Parties' Positions

All parties propose that the current eligibility threshold be increased, but significantly disagree as to the extent of the increase. The proposals range from a modest increase of 1 MW (applicable to all QF technologies other than wind) to elimination of the capacity ceiling for standard contract eligibility such that *all* QFs would be eligible for a standard contract.

All three electric utilities recommend a modest increase in the eligibility threshold. PacifiCorp and Idaho Power propose that the threshold be increased to 3 MW. PGE recommends that the standard contract ceiling capacity be increased to 5 MW for wind QFs, but only 2 MW for all other QF technologies. All three electric utilities caution against raising the threshold too high, as standard rates may overcompensate and subsidize QFs due to avoided cost calculations not being customized for particular projects. Idaho Power estimates the difference between levelized standard pricing based on the SAR methodology and alternatively calculated avoided costs to be as much as $0.01 per kWh. Idaho Power and PacifiCorp both observe that such a differential may result in a significant subsidy should it be applied to sizeable QF projects.

The utilities further comment that the primary rationale for offering standard rates to smaller QFs is to overcome prohibitive transaction costs that a very small QF must incur to negotiate a power contract.[26] They take the position that the threshold should be set no higher than essential to overcome market barriers associated with transaction costs. Although challenged by Staff, PacifiCorp initially justified the 3 MW threshold as representing the division between QF interconnection at transmission facilities, rather than a utility's distribution system. PacifiCorp also observes that a 3 MW QF project requires approximately $3 million in capital costs to construct, and argues that no evidence has been presented that a developer of a project of this magnitude or greater cannot afford the transaction costs that must be incurred to negotiate a non-

[26] PURPA regulations mandate that standard rates made available to QFs up to 100 kW only. 18 CFR § 292.304(c)(1). FERC stated in the order implementing PURPA:

> The Commission is aware that the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rates required by this paragraph. If the Commission were to require individualized rates, however, the transaction costs associated with administration of the program would likely render the program uneconomic for this size of qualifying facility. As a result, the Commission will require that standard tariffs be implemented for facilities 100 kW or less." Order No. 69, Small Power Production and Cogeneration Facilities, FERC Regulation Preambles 1977-1981 ¶ 30,128, 45 12,214 (Feb. 25, 1980, 45 Fed. Reg. 24, 126 (Apr. 9, 1980).

standard contract with avoided cost rates that fairly reflect the characteristics of the project. PGE also observes that some parties may intend to engage in negotiations regardless of the availability of standard contract rates, terms and conditions and that a standard contract would be a fallback position in such negotiations. PGE asserts that concerns raised by parties advocating a significant increase in the eligibility threshold would be better addressed by improving transparency in the transaction process between utilities and QFs.

The utilities raise particular concerns regarding the ability of intermittent resources, such as wind and solar QFs, to receive standard rates. Idaho Power asserts that standard rates, to the extent they are based on the costs of an optimized generating resource that produces firm energy, overcompensate and subsidize intermittent QFs that produce non-firm energy. On the other hand, PGE proposes to recognize the low expected energy output per MW of installed capacity for wind resources by differentiating for eligibility purposes between wind QF resources and other QF resources. PGE would raise the eligibility threshold for wind resources to 5 MW.

Staff and ODOE recommend an increase in the capacity ceiling from 1 MW to 10 MW. Staff concludes that 10 MW was the appropriate threshold after conducting a thorough study of the recent history of QF development in Oregon, an evaluation of current utility power purchasing practices, and a review of pending QF projects identified by the State Energy Loan Program (SELP). Staff argues that an increase in the eligibility threshold is warranted in order to recognize that transaction costs and *other* market barriers, such as the lack of transparency for negotiated QF contract rates, terms and conditions, prevent successful negotiation of a power purchase contract for QFs that are at or under 10 MW. Staff also argues that the 10 MW threshold recognizes the inability of smaller QFs to participate in other market opportunities to sell power, including utility solicitations. ODOE bases its 10 MW eligibility threshold on past experience with the development of local wind projects, its coordination of Oregon's Renewable Action Plan, and as manager of SELP. ODOE represents that at 10 MW, negotiation costs become a relatively small fraction of total $10 million investment costs.

ICNU, Sherman County, Simplot and Weyerhaeuser all recommend significant increases in the capacity ceiling. Weyerhaeuser recommends a 100 MW threshold, while ICNU, Sherman County and Simplot initially proposed elimination of the capacity ceiling. Ultimately, ICNU recommends a 40 MW threshold for non-wind resources, while Sherman County and Simplot indicate that a 25 MW threshold would be acceptable. Although acknowledging the argument that larger QFs should have the resources and ability to negotiate avoided cost rates and contract terms and conditions with a utility, all four parties argue that QFs of all sizes are hindered by utility advantages, particularly superior knowledge of facts regarding utility systems and energy needs. Based on the experience of the state of Idaho, Weyerhaeuser observes that a standard contract threshold effectively acts as a cap on the size of QF that operates in the state, as few, if any, non-standard contracts above the threshold ever get negotiated. Indeed, ICNU argues that the eligibility threshold for standard contracts should be significantly raised for the purpose of ensuring that utilities cannot continue thwarting power purchases from larger QFs. ICNU also asserts that no party has rebutted evidence that larger QFs have no more leverage in negotiating with utilities than small QFs, are often unable to sell electricity in the wholesale market or participate in utility RFPs, and experience unique problems in QF contract negotiations.

PacifiCorp dismisses what it calls the "black box" argument of the larger QFs, stating that the allegations that utilities exploit asymmetries in information and bargaining power when negotiating with QFs are unproven. PacifiCorp suggests that the proper manner to address concerns about an uneven playing field is to ensure greater transparency and efficiency in the negotiation process, not to expand eligibility for standard contract terms and conditions.

Idaho Power also comments that setting the capacity threshold as high as 100 MW would compromise utility resource planning. Idaho Power adds that a competitive bidding process for resources would be undermined if standard rates were available to 100 MW QFs. Moreover, the limit would be problematic if applied to Idaho Power, as the company's total load in Oregon is 108 average megawatts (aMW).

In lieu of raising the eligibility threshold to 100 MW, Weyerhaeuser recommends that the Commission provide detailed guidance about the proper scope and nature of rates, terms and conditions for non-standard contracts. Weyerhaeuser asserts that more detailed guidance would provide larger QFs with a stronger negotiation position, as well as a baseline against which to compare offered terms and conditions. Weyerhaeuser represents that evidence presented in the case, although initially introduced as support for parties' positions on appropriate standard contract terms, provides a record for the Commission to adopt more detailed guidelines for non-standard contract negotiations. Weyerhaeuser observes that Staff agrees that Commission approval of certain policies, including contract duration, calculation of avoided costs and the pricing based on gas indexing, for standard contracts should apply to non-standard contracts. Weyerhaeuser urges the Commission to use the record in this proceed to adopt a broader array of guidelines for non-standard contracts. In briefing, Weyerhaeuser sets forth proposed guidelines that it argues are supported by the record.

In briefing, ICNU also recommends that the Commission provide more specific requirements regarding negotiation of non-standard contract terms and conditions. In particular, ICNU calls for additional guidance about how Oregon's avoided cost calculation should be modified for non-standard contracts to address factors identified by FERC, such as dispatch, reliability, scheduling outages and line losses.[27] Without such guidance, ICNU argues that the standard contract eligibility threshold could practically function as a cap on the size of QF projects developed. ICNU acknowledges that the record was insufficient, however, to determine a full panoply of guidelines and urges the Commission to take up the issues in subsequent proceedings.

3. Resolution

[27] *See* 18 C.F.R. § 292.304(e).

We continue to adhere to the policy, as articulated in Order No. 91-1605, that standard contract rates, terms and conditions are intended to be used as a means to remove transaction costs associated with QF contract negotiation, when such costs act as a market barrier to QF development.[28] Standard contracts are designed to eliminate negotiations and to thereby remove transaction costs. In implementing PURPA, FERC recognized that some QF projects would be too small and have projected revenues too minimal to justify investing the upfront costs necessary to engage an attorney on an hourly basis to negotiate a QF power purchase contract. Classifying these costs as "transaction costs," FERC determined that it was appropriate to eliminate transaction costs for a defined class of very small QFs.[29] Consequently, FERC mandated that QF projects sized at 100 kW or smaller would be eligible for standard contracts.[30] FERC discerned, however, that experience might demonstrate that this threshold was insufficient and delegated authority to state commissions to increase it.[31] As individual states have gained greater familiarity with QF projects, many states have increased the minimal threshold. This Commission has done so in the past and is asked to do so again in this proceeding.

The evidence in this proceeding shows that market barriers other than transaction costs pose obstacles to a QF's negotiation of a power purchase contract. In addition to transaction costs, which in economics and related disciplines are traditionally considered to encompass only those costs that are incurred to make an economic exchange, parties identified other market barriers such as asymmetric information and an unlevel playing field that obstruct the negotiation of non-standard QF contracts. Just like transaction costs, these market barriers can render certain QF projects uneconomic to get off the ground if an individual contract must be negotiated. We conclude that it is appropriate and in keeping with the general PURPA policies of this Commission and FERC to increase the eligibility threshold for standard contracts in order to overcome economic impediments created by these market barriers.

At the same time, however, we recognize a need to balance our interest in reducing these market barriers with our goal of ensuring that a utility pays a QF no more than its avoided costs for the purchase of energy. With standard contracts, project characteristics that cause the utility's cost savings to differ from its actual avoided costs are ignored. No party presented evidence in this docket that the special characteristics of larger projects do not need to be considered in order to achieve rates that reflect actual avoided costs. Furthermore, the risk customers face because avoided costs in the future may be different from the prices paid under a standard contract (through the Fixed-Price Method, for example) is greater for a large QF than a small one.

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[28] Order No. 91-1605, at page 2 states: ". . . [T]he transaction costs associated with negotiating a QF/utility power purchase agreement could be prohibitive for small QFs and effectively eliminate them from the marketplace. The standard rate is intended to address this concern by minimizing the transaction costs of negotiating a power purchase agreement."
[29] *See supra* note 42.
[30] 18 C.F.R. § 292.304(c).
[31] 18 C.F.R. §292.304(c)(2).

We deem the recommendation of Staff and ODOE to raise the standard contract eligibility threshold to 10 MW to be reasonable.[32] We rely, in particular, on the facts that Staff's proposed threshold of 10 MW took into account the extent to which market barriers prevented successful negotiation of a contract and that ODOE, which has significant experience with the development of QF projects, indicated that 10 MW represented a point at which the costs of negotiation become a reasonable fraction of total investment costs.

We are persuaded that QFs greater in size than 10 MW face market barriers, such as asymmetric information and an unlevel playing field, that impede negotiation of a viable QF power purchase contract with electric utilities. We agree with PacifiCorp and PGE, however, and conclude that such market barriers will be best overcome for those QFs by improved negotiation parameters and guidelines and greater transparency in the negotiation process.

Although some of the evidence presented in this case could potentially support adoption of specific QF contract negotiation parameters and guidelines, as requested by Weyerhaeuser, the parties did not address the evidence from this standpoint. Even the evidence presented by Weyerhaeuser was initially introduced for the purpose of supporting appropriate standard contract terms and conditions that would be available to QFs as large as 100 MW. We conclude that the evidence in this proceeding did not receive the analysis and examination that would be needed to support the adoption of negotiation guidelines for non-standard contracts. Consequently, we direct parties to take up the issue of negotiation guidelines and parameters for non-standard contracts in the second phase of this proceeding. Although Staff identified certain issues, such as contract duration, that could potentially be resolved with regard to both standard and non-standard contracts, we conclude that it is preferable to address the full scope of non-standard rates, terms and conditions on a collective basis. Consequently, we decline to adopt rates, terms and conditions, or associated parameters or guidelines, for non-standard contracts, except to the extent that we do so explicitly.

B. STANDARD CONTRACT LENGTH

1. Parties' Positions

All parties proposed a significant increase in the term of standard contracts. Proposals to increase the maximum standard term from five years ranged up to thirty years and beyond for some QF technologies. Most parties advocate increasing the maximum standard term from five to either fifteen or twenty years. Parties preferring a fifteen year term for standard contracts raise concerns that standard rates will not track avoided costs over too long of a term. They caution that the risks are great, pointing to past history when high QF rates were locked in for terms up to thirty-five years. Parties that favor an increase to twenty years, however, express concern that financing for many QF projects requires the longer term.

[32] Having raised the eligibility threshold to 10 MW, we decline to distinguish between wind and non-wind QF resources by instituting a higher eligibility threshold for wind resources.

PacifiCorp, PGE, Idaho Power[33] and Staff each propose that the maximum standard contract term be fifteen years, with QFs having the discretion to request any term up to the maximum. The consensus of these parties is that the maximum standard contract term should be no longer than necessary to facilitate QF financing. All indicate that a term of fifteen years represents an appropriate balance between attracting QF financing and limiting the risks that accompany long range power price forecasting.

A primary basis for Staff's recommendation for a 15-year maximum term are past representations by the ODOE that fifteen years is a sufficient financing period for some QF projects, and that certain QF project developers have requested 15-year loans in the recent past. Staff particularly relies on a letter sent in December 2003 from the loan program manager for ODOE's SELP to the Commission that indicates 15 years was a usual term for QF contracts.[34] Staff is reluctant to support a contract term longer than 15 years due to the likelihood that fixed avoided cost rates would diverge over time from actual avoided costs. Moreover, Staff recognizes that utilities must enter into must-take QF contracts without the full evaluation of cost and risk that would be associated with other power resources. PacifiCorp and PGE concur. While PGE observes that it is inappropriate to compare terms for QF contracts with terms for other utility resources due to the discretion and safeguards associated with those resources, all three parties note that 15 years is within the range of other utility resources.

ODOE recommends a maximum term of 20 years, noting that such time frame generally represents the middle point of typical terms for other utility resources. ODOE disagrees with Staff's claim that a term of fifteen years is sufficient to attract financing. ODOE indicates that since 1980, ODOE's loan program has financed twenty-one QF projects. Of those, sixteen projects have been financed for periods of twenty to twenty-five years, three for shorter terms, and two for longer. ODOE asserts that "twenty years should allow for adequate financing of the majority of QF projects our program has reviewed,"[35] and notes that some QF projects will be economically feasible only with a twenty-year term. Sherman County, Simplot Company and Weyerhaeuser concur that the maximum standard contract term should be twenty years. Weyerhaeuser adds that the Commission should provide that existing standard contracts may be renewed for ten years.

Two parties argue that the maximum term for standard contract term should be, in many cases, much longer than twenty years. FRC does not specify what the

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[33] Observing that the Idaho Commission has authorized twenty year QF contracts in Idaho, Idaho Power notes that 20-year terms in Oregon would provide administrative ease for the Company. Idaho Power further observes, however, that the QF contracts have protections that may not be authorized in Oregon. Consequently, Idaho Power requests that it be allowed to implement some of the same provisions authorized by the Idaho Commission in Oregon should a maximum standard contract term of 20 years be adopted in Oregon.

[34] The letter stated: "As a lender, it is important to have a power purchase contract that equals the loan term, usually fifteen years." Staff 200 at 6; *See* Staff 202 at 1.

[35] ODOE 3 at 2.

initial term of a QF contract should be, other than to say it should be as long as reasonably possible. FRC does, however, seek an evergreen provision that would effectively extend a QF contract over the entire economic life of a QF project. An evergreen provision would allow a QF, at its sole discretion, to continually renew a QF contract, presumably as long as the QF was able to economically operate under the contract. ICNU, on the other hand, asserts that QF contracts should extend, from the start, through the economic life of a facility. For example, a hydro QF project would be eligible to receive a standard contract for a term of up to fifty years, while a biomass QF would be eligible to receive a standard contract with a term between ten and fifteen years. ICNU asserts that financing is difficult and more expensive to obtain when contract lives are less than economic lives, and that matching QF contract life with economic life treats QF projects on par with how other utility resources are addressed.

2. Resolution

We conclude that establishing an appropriate maximum term for standard contracts requires us to balance two goals. A primary goal in this proceeding is to accurately price QF power. We also seek, however, to ensure that QF projects that are deemed eligible to receive standard contracts have viable opportunities to enter into a standard contract. To achieve this latter goal, it is necessary to ensure that the terms of the standard contract facilitate appropriate financing for a QF project. Consequently, we agree with Staff and other parties 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.

In adopting this objective, we implicitly reject the position advocated by FRC and ICNU that the life of a QF contract should extend, at the discretion of the QF developer, over the entire economic life of the project. We observe that neither FRC nor ICNU presented evidence indicating that the economic viability of a QF project requires financing that is equal to the economic life of the QF facility. Although ICNU represented that such financing would put QFs on par with utility resources, ICNU did not assert that such financing was *required* for the viability of QF projects. Although a QF project may have an economic operating life of up to 50 years, it is probable that the project may be initially financed over a period far less than its economic life.

We conclude that the contract term length minimally necessary to ensure that most QF projects can be financed should be the maximum term for standard contracts. The evidence presented in this proceeding is inconclusive, however, about whether that length of term is 15 or 20 years. No party was definitive regarding a recommendation. For example, although PacifiCorp consistently recommended that 15 years be established as the maximum standard contract, PacifiCorp did so with some ambiguity, stating: "[a] contract term of 15 years *should be* adequate to address the financiability concerns raised in this proceeding."[36]

[36] PacifiCorp Opening Brief at 4; PacifiCorp 100 at 5 (emphasis added).

No party, other than ODOE which finances QF projects through SELP, presented testimony about the appropriate term for QF contracts from entities that are likely to finance the projects. Although Staff presented evidence that ODOE has represented in the recent past that 15 years is an appropriate term, ODOE itself argued in this proceeding that 20 years is minimally adequate.

Given its role as a facilitator and financier of QF projects, we find ODOE's testimony to be the most persuasive in this proceeding. Consequently, we adopt ODOE's recommendation that the maximum term of a standard contract be raised to 20 years. In so doing, however, we acknowledge that 20 years is a significant amount of time over which to forecast avoided costs. Indeed, divergence between forecasted and actual avoided costs must be expected over a period of 20 years. Given our desire to calculate avoided costs as accurately as possible, and the testimony of several parties that avoided costs should not be fixed beyond 15 years, we are persuaded that standard contract prices should be fixed for only the first 15 years of the 20-year term. Tariffs and standard contract terms should provide that, in the event a QF opts for a standard contract with a 20-year term, the QF must take one of the market pricing options that we address later in this order for the final five years of the contract.[37]

C. CALCULATION OF STANDARD AVOIDED COSTS

1. Overview

FERC defines a utility's full avoided costs as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[38] Thus, the goal of calculating avoided costs is to accurately estimate the costs a utility would incur to obtain an amount of power that it purchases from a QF, either by the utility's self-generation or by purchase from a third party. Each utility serving customers in the state of Oregon currently utilizes an individualized methodology to calculate avoided costs.

QFs with design capacities larger than the relevant standard contract threshold are still entitled to sell power to a utility at avoided costs, but receive avoided cost rates that are individually negotiated with a utility to reflect specific characteristics of the project and its interconnection with the utility. Negotiations typically start with the standard avoided costs, however.[39] Consequently, in setting standard avoided costs, we

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[37] *See discussion*, page 34.

[38] 18 C.F.R. § 292.101(b)(6).

[39] 18 C.F.R. § 292.304(e). Non-standard avoided cost rates deviate from standard avoided costs in order to reflect the following considerations set forth by FERC:

(1) The utility's system cost data;
(2) The availability of capacity or energy from a QF during the system daily and seasonal peak periods, including:
  (i) The ability of the utility to dispatch the qualifying facility;
  (ii) The expected or demonstrated reliability of the qualifying facility;
  (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

acknowledge that we are also setting a starting point for negotiation of rates for non-standard contracts.

2. Parties' Positions

Calculation of each electric utility's standard avoided costs begins with the utility filing an integrated resource plan (IRP) for a 20-year planning horizon, as required every two years. Within thirty days of the Commission's acknowledgement of an IRP, the utility makes an avoided cost filing based on its IRP, but updated as appropriate.[40] Consistent with IRP filings, utilities calculate avoided costs for a period of 20 to 25 years.

Each utility represents that its current avoided cost methodology has been designed to capture the avoided costs actually realized by the electric utility when it purchases power from a QF. For example, PGE considers it appropriate to use expected wholesale power market prices to determine avoided costs for its system due to PGE's significant market purchases. PGE observes that paying market prices to QFs equates to PGE purchasing power on the market, which is consistent with its current operations.

PGE further explains that, as of its 2001 avoided cost filing, PGE bases avoided costs on projections of the wholesale market price of energy delivered to PGE's system. The 2001 filing listed expected market prices for a period of 20 years, as calculated by PGE's Multiple Area and Network Energy Transaction (MONET) model. Initially, in years 2001 and 2002, PGE based avoided costs on a published electricity index of forward trading prices for the Pacific Northwest. Since 2003, PGE bases avoided costs on a published index indicative of natural gas prices in the Northwest and a correlation factor that reflects the relationship between electricity and gas prices. PGE represents that as fixed costs of new resources added over time are fully reflected in long-term market prices, separate fixed capacity and energy components are not appropriate. PGE also indicates that capacity contracts are no longer available in the marketplace at economic prices. PGE separates QF power deliveries into firm and non-firm categories. Assuming firm power prescheduled and delivered flat across each hour, as well as a strong correlation to gas prices, avoided costs paid to a QF are based on an indexed

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(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a QF, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

[40] *See* OAR 860-029-0080(3).

expected market price. Standard contract rates are based on the average of expected market prices for a year, broken down by season and on- and off-peak. Non-standard contracts are customized for the characteristics of the QF project. PGE challenges the appropriateness of paying capacity fees for non-firm energy for which there is no delivery commitment.

PGE's current avoided calculation represents a break with tradition. Historically, when in a period of resource surplus or sufficiency, Oregon electric utilities have calculated avoided costs based only on the variable costs of operating existing generating facilities. In periods of resource deficiency, the calculation of avoided costs has historically included both the variable and fixed costs of avoided resources. Recent utility resource plans identify a natural gas-fired combined cycle combustion turbine (CCCT) as a proxy plant for calculating costs that can be avoided when QF power replaces new utility resources. The theory that underlies separate calculations for periods of resource sufficiency and deficiency is that a utility is actively planning to acquire, and therefore can actually avoid acquiring new resources, only when the utility is in a resource deficient position.

PacifiCorp's current avoided costs methodology is founded on the historical approach. PacifiCorp explains that its avoided costs are based until 2006, while PacifiCorp is in a resource sufficient position, on the marginal production cost of existing units. Beginning in 2007, PacifiCorp anticipates needing new resources to provide summer and winter capacity as well as additional energy to meet its resource requirements, and therefore bases its long term avoided costs on CCCT costs.

To calculate avoided costs, PacifiCorp begins with the load and resource balances developed in conjunction with its 2003 IRP planning process. During periods of resource sufficiency, PacifiCorp calculates avoided energy costs based on the displacement of purchased power and existing thermal resources, as modeled by the company's GRID model, with data input that includes the 2003 IRP monthly load and resource data. To calculate the short-run avoided costs, PacifiCorp compares the difference between two production cost studies, with one study assuming a 50 aMW increase in system resources, at zero running cost, to serve as a proxy for QF generation. During periods of resource insufficiency, PacifiCorp determines avoided costs based on the fixed and variable costs of a CCCT as a proxy for the planned resource that could be avoided or deferred. Since CCCTs are built as base load units that provide both capacity and energy, it is appropriate to split the fixed costs of this unit into capacity and energy components. To determine the portion of fixed costs allocated to capacity, PacifiCorp uses the fixed cost of a single-cycle combustion turbine (SCCT), which is usually acquired as a capacity resource, to define the portion of the fixed cost of the CCCT that is assigned to capacity. Fixed costs for a CCCT in excess of SCCT costs are assigned to energy and are added to the variable production (fuel) cost of the CCCT to determine the total avoided energy costs. The fuel cost of the CCCT, based on gas price forecasts, defines the variable energy costs. Avoided energy costs can be differentiated between on-peak and off-peak periods. To make this calculation, PacifiCorp assumes that all capacity costs are incurred to meet on-peak load requirements.

As explained in Idaho Power's informational filing, Idaho Power also breaks with the historical approach and uses the surrogate avoided resource (SAR) methodology to calculate avoided costs for Oregon. Idaho Power uses input and cost variables that are associated with a surrogate CCCT, as approved by the Idaho Public Utilities Commission.[41] Idaho Power prepares an annual forecast of on-peak and off-peak avoided costs for the surrogate CCCT that have been adjusted for seasonal differentiation and use a gas price forecast derived from the Draft Fuel Price Forecasts for the Fifth Northwest Conservation and Electric Power Plan that was issued by the Northwest Power Planning Council on April 25, 2002. Prices for generation during off-peak hours reflect the variable costs of the surrogate CCCT, while prices for generation during peak times reflect capitalized costs plus variable costs. If a QF cannot commit to provide firm power, power will be purchased from that QF at a price that reflects only the value of the energy.

When PGE and PacifiCorp are in a resource-deficit position, Staff recommends that these utilities use the historical methodology to calculate avoided costs. Staff disagrees with the premise that a utility need not pay a QF for capacity during a resource surplus period, however. Staff maintains that QF capacity during a resource surplus period has value to the utility, as the utility can sell capacity into market or use the additional capacity to improve reliability. ODOE agrees, stating:

> Planning reserve margins for capacity resources are a target to maintain an adequate but not a perfect level of reliability. It is always useful to have increased reliability from having more capacity resources.[42]

Staff and ODOE also identify advantages to incremental capacity added by QFs, rather than lumpy capacity being added by new utility plant. When the utility is in a resource-surplus position, Staff asserts that capacity should be valued, using one of two methodologies that would establish a "market-based" value for avoided capacity costs.

One methodology would value avoided costs at the sum of the variable cost of operating existing generating facilities, plus the price of capacity in the wholesale market. Staff recommends that this methodology, when employed in standard contracts, be combined with levelization of the avoided capacity costs. Although ODOE would prefer use of the SAR methodology to calculate avoided costs at all times, if market pricing is used to value avoided cost, ODOE argues that separate market prices for capacity should be included in the calculation. ODOE represents that capacity is routinely sold among utilities in Western and Northwestern regions and can be valued on a market basis. Although Staff generally opposes levelization, Staff contends that levelization of avoided capacity payments when a utility is resource sufficient is appropriate, as compensation for a QF's assistance in meeting future demand growth and as a means to encourage QF development.

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[41] IPUC Order 29124.

[42] ODOE 1 at 4, lines 9-11.

The utilities oppose any levelization of payments. Observing that levelization front-loads payments, the utilities warn that levelization of payments increases ratepayers' risks. Indeed, PGE and Idaho Power characterize levelization as a loan that imposes the risk of default on ratepayers. Should the Commission adopt levelization in any form, the utilities argue that greater security requirements will be necessary.

The second methodology would value avoided costs at monthly on- and off-peak forward market power prices as of a utility's avoided cost filing, thereby embedding the market value of capacity in the avoided cost rate. Staff ultimately prefers the adoption of this market-based methodology, as does PacifiCorp and ODOE. ODOE notes that forward firm energy markets at the Mid-Columbia hub are more liquid and standardized than markets for capacity contracts.

Staff would apply either market methodology to both intermittent and firm resources. Staff asserts that intermittent resources are, on average, available during peak hours and should, therefore, receive capacity credit. Staff recommends against always reducing avoided cost payments to energy-only payments when a QF delivers less energy than expected.[43]

Staff also recommends imposing a mechanical availability guarantee (MAG) in each standard contract. The MAG would be based on the QF's capability to produce power based on the project's capacity factor, with consideration for factors that reduce capability, including scheduled maintenance, system emergencies or a force majeure event. If they do no meet the availability threshold, utilities would be able to reduce QF payments to energy-only rates, subtracting the capacity component until the QF demonstrates that it has corrected production problems. PGE criticizes Staff's proposed MAG as guaranteeing little. ODOE, on the other hand, is concerned that the MAG could unduly penalize a QF for operational unavailability that is beyond its control. As an example, ODOE points out that maintenance delays could be extended by a third party vendor. ODOE also argues that, should the MAG result in the reduction of capacity payments, the reduction should be implemented as a reduction in future payments and that QFs should be allowed to demonstrate the reinstitution of mechanical availability within 30 days.

With regard to Idaho Power, Staff recognizes the administrative efficiency advantages of having consistency between the company's avoided cost calculations in its Oregon and Idaho jurisdictions. Consequently, Staff recommends that Idaho Power be authorized to use the SAR methodology in Oregon, regardless of whether Idaho Power is in a resource surplus or deficit position, with only one modification: Idaho Power should be required to file avoided costs for on- and off-peak hours. Staff recommends that all other requirements adopted by the Commission in this docket apply to Idaho Power. PacifiCorp does not oppose authorization of a different avoided costs calculation for Idaho Power.

In order to facilitate implementation of its pricing recommendations, Staff proposes one additional requirement for avoided costs calculations. Staff recommends that utilities develop avoided costs for both a fixed set of prices and an indexed set of prices. As will be further discussed, the fixed avoided costs would be used, for pricing purposes, as a basis for Staff's fixed pricing option while the indexed avoided costs would be used as a basis for rates developed pursuant to Staff's Deadband and Gas Market methods.

For varying reasons, ODOE, Sherman County and Simplot recommend that the Commission not differentiate with regard to the calculation of avoided costs when a utility is in a resource deficient position versus a resource sufficient position, and urge the Commission to adopt the SAR methodology, as approved by the Idaho Commission, to calculate avoided costs at all times. Sherman County and Simplot oppose calculating different avoided costs depending on whether a utility is in a resource surplus or deficit position based on administrative burden and concerns that utility planning processes minimize resource deficits. They observe that the need to determine a utility's resource position requires resolution of issues such as IRP assumptions relative to load growth projections and water year averages. Sherman County and J. R. Simplot primarily recommend that the Commission adopt the SAR approach for administrative ease. Similarly, ODOE argues that it is difficult to distinguish between when a utility is resource deficient as opposed to sufficient. Moreover, ODOE objects to the current calculation of avoided costs when a utility is in a resource deficit position. ODOE's objection is based on the volatility and uncertainty about market prices and concerns about proper valuation of capacity. ODOE favors SAR's valuation of avoided costs in all years at the full cost of a CCCT.

ICNU recommends that avoided costs be based on utility-specific resources or a proxy CCCT as a surrogate resource. Similarly, Weyerhaeuser objects to avoided costs reflecting only variable costs until the first year a utility is in a supply deficit position. Weyerhaeuser argues that avoided costs should reflect the full costs of an avoidable resource, generally agreed to be represented by a CCCT. Weyerhaeuser also supports the incremental capacity additions of QFs. Weyerhaeuser would make an exception, however, if a utility could demonstrate that it is in a resource surplus position that is likely to last more than five years.

Staff and the utilities object to the global application of the SAR methodology on several grounds. PGE deems the SAR methodology to be an artificial construct that doesn't adequately capture avoided costs for individual utilities. Another complaint, as articulated by Staff and PacifiCorp, is that SAR fails to differentiate avoided costs by season or time of day. Unlike the historical volumetric pricing model used by PacifiCorp, the SAR methodology would spread capacity benefits across all hours and would not differentiate between seasons or peak and off-peak hours, thereby removing incentives for QFs to deliver power when it is most needed. PacifiCorp states that utilities receive a capacity benefit from QF deliveries during peak hours and that volumetric pricing aligns the payment of capacity benefits with periods when surplus capacity has the greatest reliability benefits. PacifiCorp also argues that SAR's elimination of any differentiation between a utility's resource surplus and deficit position results in ratepayers paying too much, because utilities back down less expensive resources due to surplus QF capacity. Staff agrees, but notes that capacity always has some value.

3. Resolution

A primary dispute among the parties with regard to the calculation of avoided costs centers on the question of whether the calculation should be differentiated in order to reflect a utility's resource position. If we conclude that the calculation should be differentiated, parties debate what the scope and nature of that differentiation should be.

Parties arguing that there should be no differentiation uniformly recommend that we adopt the SAR methodology as a singular approach to calculating standard avoided cost rates, regardless of a utility's resource status. These parties introduced little evidence, however, that the SAR methodology is a substantively better approach than the historical methodology to calculate avoided costs when a utility is in a resource deficient position.

We are reluctant to abandon this Commission's long history of differentiating the calculation of avoided costs for a utility in a resource deficit position from a utility in a surplus position. The historical differentiation is based on recognition that a utility's avoided costs differ depending on the resource position of the utility. In a period of resource deficiency, the historical calculation of avoided costs has included both the variable and fixed costs of a planned resource in order to reflect the actual deferral or avoidance of that resource. In a period of resource sufficiency, however, the historical calculation of avoided costs has included only the variable costs of operating an existing resource, reflecting the inability of a resource sufficient utility to defer or avoid a resource when QF generation is committed.

We remain convinced that the accurate calculation of avoided costs requires differentiation when a utility is in a resource sufficient position versus a resource deficient position. As it is one of our primary goals to ensure that avoided costs are calculated accurately, we are not persuaded that the procedural administrative efficiency benefits of using the SAR methodology in all situations outweigh the substantive benefits of using different calculations depending on a utility's resource position. Consequently, we decline to adopt the SAR methodology as a singular approach to calculating standard avoided cost rates.

We find that administrative efficiency interests do, however, justify authorizing Idaho Power to continue using the SAR methodology to calculate avoided costs regardless of its resource position. In recognition of the fact that Idaho Power exclusively uses the SAR methodology in its Idaho service territory, where it serves far more customers than its Oregon service territory, we find that the administrative burdens to Idaho Power of developing and applying new avoided cost methodologies in Oregon outweigh the potential benefits and justify allowing Idaho Power to continue to use the SAR methodology. Consequently, we direct Idaho Power to continue using the SAR methodology to uniformly calculate avoided rates in Oregon.[44] We adopt Staff's proposed modification to this practice, however; Idaho Power should file avoided costs for on-peak and off-peak hours.

As for PacifiCorp or PGE, we adopt Staff's recommendation that these utilities apply the methodology historically used in Oregon to calculate avoided cost rates when either is resource deficient. Pursuant to this methodology, avoided cost rates for PacifiCorp and PGE, when either utility is in a resource deficient position, will reflect the variable and fixed costs of a natural gas-fired CCCT. In the second phase of this proceeding, parties may address whether the new resource used to determine avoided costs in the deficit period should instead be identified in the utility's IRP (which may select something other than a natural gas-fired CCCT).

Consequently, we direct PGE to discontinue using the market-based methodology it most recently employed to calculate avoided costs. In doing so, we find the substantive concern raised by ODOE regarding the use of market prices to have merit. The calculation of avoided costs when a utility is in a resource deficient position should reflect longer term resource decisions that are subject to deferral or avoidance due to QF power purchases. Although a utility may acquire market resources as demand gradually builds, at some point the increase in demand warrants the utility making plans to build or acquire long-term generation resources. At that point, calculation of avoided costs should reflect the potential deferral or avoidance of such generation resources. In Docket No. LC 33, we recently addressed PGE's long-term resource plans, which include development of a new electric generation resource.[45] Based on these long-term resource plans, we deem it appropriate for PGE to calculate avoided costs based on the historical approach.

Having determined that calculation of avoided costs will be differentiated to reflect a utility's resource position, we next address the more fundamental dispute among the parties regarding the scope and nature of such differentiation. We conclude that the basis for differentiation should not be whether capacity is valued *at all*, but *how* it is valued. When in a period of resource sufficiency, PGE and PacifiCorp have historically calculated avoided costs based only on the variable costs of operating existing generating resources. Staff and several other parties, however, challenged the lack of capacity payments to QFs when a utility is in a resource sufficient position, arguing that QF capacity has at least some value to utilities at all times and that this value should be compensated for.

When a utility is in a resource sufficient position, we adopt Staff's recommendation that QF capacity be valued based on the market. Although valuation of QF capacity based on the market price of capacity itself has significant appeal, we are concerned about inconsistent evidence regarding the viability of the market for capacity.

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[44] As we note throughout this order, this is the only exception we make for Idaho Power. All other resolutions of issues in this order shall apply to all electric utilities operating in Oregon, including Idaho Power.

[45] *See* Order Nos. 04-375 and 04-376.

Consequently, of the two market-based valuation methodologies proposed by Staff, we adopt the methodology that values avoided costs when a utility is in a resource sufficient position at monthly on- and off-peak forward market prices as of the utility's avoided cost filing.[46] We agree with Staff that this approach embeds the value of incremental QF capacity in the total market-based avoided cost rate. We find this valuation mechanism to be appropriate given the likelihood that a utility will address probable gaps between increasing demand and actual resources, in the absence of incremental QF capacity, with purchases of energy and capacity on the market. Indeed, we find PGE's recent history of buying significant resources on the market prior to a commitment to build new utility plant to be illustrative. To the extent that a party can provide evidence regarding the market pricing of capacity, however, we remain open to reconsideration of this decision in the next phase of this proceeding.

Although we find that firm energy provides the most reliable capacity benefits, we are persuaded by Staff's argument regarding the average availability of intermittent resources. Consequently, we conclude that intermittent and firm resources should be valued equally,[47] and direct utilities to pay full avoided costs pursuant to the appropriate methodology for all energy delivered under a QF standard contract, but only up to the nameplate rating of the facility. As electric utilities cannot expect and, therefore, would not rely on deliveries of excess energy in any manner, we conclude that energy delivered in excess of the nameplate rating does not provide capacity benefits that warrant payment of full avoided costs. Because we conclude that utilities have a legal obligation to take all energy provided by a QF, we direct the utilities to accept delivery of excess energy, but to compensate QFs for only the energy itself and not capacity. In such situations, utilities should use the methodology that has historically been used when utilities are in a resource deficient position.

Given our position that a QF's commitment of firm energy is preferable to non-firm deliveries, we are intrigued by Staff's proposed MAG. We find, however, that the evidence introduced regarding the MAG is too limited to make any determinations about its viability and suitability. For example, although Staff indicated that a QF's MAG would be based on the QF's capacity factor, adjusted for consideration of factors that reduce this capacity, including maintenance, system emergencies or a force majeure, there was little discussion among the parties about how these adjustments would be applied in standard contracts. Without further development of such details we conclude that the MAG would likely lead to contractual disputes which would undermine the purpose of standard contracts. Consequently, we decline to require a MAG.

Finally we note that in our view, issues relating to the scope, nature and quality of QF energy, and the effects of these factors on the calculation of avoided costs, were inadequately developed factually by the parties. A second phase of this investigation is anticipated. We envision an ongoing process to improve opportunities

[46] As we do not adopt Staff's proposed methodology that would separately value capacity and pay levelized rates, we need not address the issue of levelization in this Order.
[47] Parties may present evidence on the value of intermittent power vis-à-vis firm power in the second phase of this proceeding.

for QF power at realistic avoided cost rates. Consequently, we encourage parties to further refine such issues and to raise them for reconsideration, as appropriate, in the second phase of this proceeding.

D. FREQUENCY OF SETTING AVOIDED COSTS RATES

1. Parties' Positions

Three parties commented on how often avoided cost rates should be filed with the Commission and reviewed and approved. PacifiCorp recommends that electric utilities be allowed to update avoided costs more frequently than every two years in order to reflect new resources being added to a utility's system. Both Staff and ODOE support maintaining the current filing schedule which requires each utility to make an avoided cost filing every two years coincident with the IRP process. Staff objects to PacifiCorp's proposal, calling it "unbalanced" as it would allow a utility to update avoided costs when a change in circumstances causes the utility to be in a resource sufficient position, but would fail to direct a utility to update avoided costs when a change in circumstances causes the utility to be in a deficit resource position.

2. Resolution

We affirm the continued use of a two-year filing cycle for avoided cost rates. We acknowledge, however, that circumstances can significantly change within a short period of time to render avoided costs outdated. As it is our overriding goal to accurately assess avoided costs on an ongoing basis, we deem it appropriate to introduce some flexibility into the process that is used to establish avoided cost rates.

Understanding that circumstances may change to make existing avoided cost rates either too low or too high, we recognize that other parties besides the utility may wish to address avoided cost rates on an unscheduled basis. Consequently, we will exercise our discretion, when appropriate, to direct a utility to make an avoided cost filing between scheduled filings. The Commission may institute a supplementary proceeding to review a utility's avoided costs on its own motion or at the request of any party. We encourage parties to notify the Commission when it may be appropriate to review avoided cost rates between filing deadlines.

We also note that this issue intersects with the filing cycle issues identified by Staff for future consideration.[48] Consequently, we expect that the issue may receive further attention in the future.

[48] *See supra* note 4.

E. ADDER ON AVOIDED COSTS

1. Parties' Positions

FRC represents a class of very small QFs with installed capacities that are less than 500 kilowatts. FRC argues that the class of QFs under 3 MW (or alternatively, under 1 MW) should be paid an "adder" of .5 to 1.5 mills to recognize the reliance of this class of QFs on a reasonable rate at the time that QF projects were initially developed, or to compensate this class of QFs for the additional costs that utilities and ratepayers avoid through the benefits conferred by small QF generation. FRC indicates that these benefits include civic and community advantages, geographical diversity and aesthetics.

FRC offers a recent case decided by the Vermont Public Service Board (Vermont Commission) as support for its position.[49] FRC represents that the Vermont Commission approved an avoided cost adder to compensate for the time lag in utility payments to QFs and argues that this authorization is analogous to the adder requested by FRC.

Staff and PGE both oppose the proposed adder. PGE asserts that the adder would be compensation in excess of avoided costs, while Staff points out that any environmental benefits are already rewarded due to the QF's retention of renewable certificates, also known as green tags, than can be traded or sold on the market.

2. Resolution

Pursuant to section 210(b) of PURPA, the rate paid to QFs cannot exceed the incremental cost to the utility of alternative electric energy. Consequently, in setting avoided cost rates, only costs which would actually be incurred by a utility in lieu of purchasing QF power may be compensated for by rates that are based on avoided costs. The authority of states to prescribe rates for sales by QFs that exceed avoided costs is clear: states are preempted from doing so by section 210(b) of PURPA.[50] With regard to environmental costs, FERC has specifically held:

> Under section 210(b) of PURPA, 'no rule . . . shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.' Thus, in setting avoided cost rates, a state may only account for costs which actually would be incurred by utilities. A state may, through state action, influence what costs are incurred by the utility. Thus, accounting for

[49] *In Re 14 Vermont Electric Utilities*, Docket No. 6270, Vt. P.S.B, 212 PUR 4th 405, 2001 WL 1359779 (2001) (pagination not available).

[50] *See Connecticut Light and Power Company*, 70 FERC 61,012 (January 11, 1995), reconsideration denied, 71 FERC 61,035 (Connecticut statute requiring purchase of QF energy at retail rate preempted by section 210 of PURPA insofar as the statute requires rates that would exceed avoided cost); *Midwest Power Systems, Inc.*, 78 FERC 61,067 (January 29, 1997) (Rates prescribed by Iowa Utilities Board for wind-generated QF power preempted by PURPA to the extent they are in excess of avoided costs)

> environmental costs may be part of a state's approach to encouraging renewable generation. For example, a state may impose a tax or other charge on all generation produced by a particular fuel, and thus increase the costs which would be incurred by utilities in building and operating plants that use fuel. Conversely, a state may also subsidize certain types of generation, for instance wind, or other renewables, through, e.g., tax credits.
>
> A state, however, may not set avoided cost rates . . . by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities. Such practices would result in rates which exceed the incremental cost to the electric utility and are prohibited by PURPA.[51]

Although FRC identifies several benefits of small QF generation, FRC fails to identify how those benefits actually result in costs that a utility incurs in the absence of purchasing power from small QFs. Without such evidence, we must conclude that an adder on standard avoided cost rates would represent costs in excess of avoided costs which PURPA prohibits us from approving.

In addition, we find FRC's reliance on the cited Vermont case to be misplaced. Because the case was decided on the grounds that the fee at issue was not an avoided cost adder, it is inapposite to FRC's specific request that the Commission authorize an adder for QFs under 3 MW. In that case, Vermont utilities sought to eliminate or minimize "payment lag adders" in existing contracts with QFs.[52] The QFs responded that doing so would deprive them of the time value of avoided cost payments, which would effectively reduce their avoided cost rates.[53] According to the utilities, however, the payment lag adders were not required by PURPA or regulation by FERC and were, therefore, independent of the calculation of avoided costs such that reducing the adders would not change avoided cost rates.[54] The Vermont Commission agreed that the payment lag adders were not part of avoided cost rates, representing instead separate compensation in the agreements to account for the time value of money paid under those agreements, and concluded that PURPA did not preempt the relief requested by the utilities.[55]

For these reasons, we reject FRC's proposal for an adder to avoided costs for QFs sized at or less than either 3 MW or 1 MW.

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[51] *Southern California Edison Company, San Diego Gas & Electric Company*, 71 FERC 61,269 (June 2, 1995).
[52] *In Re 14 Vermont Electric Utilities* (pagination not available).
[53] *Id.*
[54] *Id.*
[55] *Id.*

F. PRICING

1. Parties' Positions

Determining what methodology to use to calculate avoided costs is one step of a two-step process to establish the price that utilities will pay for electric power supplied by QFs under standard contracts. A second step involves applying the avoided cost methodology within a pricing structure to compute standard rates. Currently, a volumetric pricing structure is employed by all three of the electric utilities.

Staff recommends implementing more pricing options than currently exist for standard contracts. In addition to a Fixed Price Method, Staff proposes two variable pricing options which are respectively identified as: (1) the Deadband Method; and (2) the Gas Market Method. Both options would alter how QF payments are calculated.

The Fixed Price Method would pay prices, established at the time the contract is executed, over the contract's entire term. Under this option, a utility would pay fixed rates that are based on a single set of forecasted natural gas prices in the utility's last approved avoided-cost filing. The Fixed Price Method would remit a total avoided energy cost, calculated as the cost of energy plus capitalized energy costs at a certain capacity factor based on a natural gas price forecast, with prices modified to account for shrinkage and transportation costs.

The Deadband and Gas Market Methods would base the fuel price component of QF rates on monthly natural gas price indexes. The Deadband Method would bound the rates that a QF receives within a floor and ceiling based on 90 percent and 110 percent of the natural gas price forecast that is included in the avoided-cost filing in place at the time of the contract execution—*i.e.*, the same natural gas price forecast used to set fixed rates. The Gas Market Method uses a monthly indexed price with no forecast to set avoided cost rates. Staff contends these two pricing options allow QF prices to reflect ongoing market conditions, rather than tying prices to a long-term natural gas forecast that is subject to inaccuracy. Staff opines that hydro and wind QFs would likely prefer the Deadband Method, while natural gas-fired cogeneration QFs would choose the Gas Market Method.

Under either of these market methods, the total avoided energy cost of the traditional avoided cost payment would be replaced by two index components, the actual natural gas price used (AGPU) and a factor for non-index costs (NIC), such as shrinkage, transportation and capitalized energy costs that are not accounted for by an index. The off-peak price of energy would equal the sum of AGPU and NIC. To calculate the on-peak price of energy, the off-peak price would be added to avoided capacity costs allocated to on-peak hours.

The AGPU would be calculated differently under Staff's two proposed market methods. The Deadband Method would require calculation of the fuel index price, which requires the appropriate forecast natural gas price contained in the utility's then approved avoided cost filing being multiplied by the assumed heat rate of the applicable CCCT, as well as calculation of floor and ceiling prices based on 90 percent and 110 percent of this forecast natural gas price. The weighted monthly average index price of natural gas at Sumas would then be compared against the deadband values and, if over or under, the floor or ceiling would be used as the AGPU. Under the Gas Market Method, AGPU would equal the monthly indexed gas price, multiplied by the heat rate of the applicable CCCT.

Staff proposes to differentiate the availability of the options based on QF size. QFs under two megawatts in size would be allowed to select either the Fixed Price option or the Gas Market Method. QFs that are greater than two megawatts but under the maximum threshold for standard contract eligibility would select between the Deadband and the Gas Market Methods. QFs ineligible for standard contracts due to their size would be required to negotiate a custom pricing structure.

Staff argues that the proposed market methods accommodate differences among QFs with different fuel types regarding financing needs, market access, and levels of risk aversion. Moreover, Staff asserts, the proposed market methods better reflect the actual market price for electricity, thereby ensuring more accurate avoided cost payments and insulating ratepayers from harm of paying too much for power. Indeed, Staff acknowledges the probability that market prices will deviate from forecasted prices over time and advises against allowing QFs larger than two megawatts to select the Fixed Pricing Option.

PGE also proposes that QFs have three pricing options. PGE agrees that a fixed price option is appropriate. PGE also agrees an option that indexes the variable cost component of avoided costs to a natural gas index is appropriate. However, PGE proposes that an annual natural gas index be used rather than a monthly index. Staff counters that a monthly index better reflects variations in natural gas prices throughout the year, giving QFs more accurate price signals and capturing avoided costs better.

PGE does not support Staff's Deadband Method, observing that this option would provide a QF with a fixed price stream while subjecting either the QF or ratepayers to risk should the prices swing significantly above the ceiling or below the floor. Instead, PGE proposes an alternative market pricing option that would offer a daily indexed rate based on the Dow Jones Mid-Columbia electricity price index (Mid-C index). As PGE generally buys energy on the market, PGE asserts that it is appropriate to have PGE's avoided costs set by the market. PGE also notes that the Mid-C index has the advantage of varying by season and on- and off-peak. For these reasons, PGE argues the Mid-C index option would be a "viable and highly transparent pricing mechanism" that sends appropriate price signals to QFs and allows QFs to participate in wholesale market opportunities. Staff supports PGE's proposed Mid-C index rate option as a pricing methodology to be offered by PGE, but not PacifiCorp since PacifiCorp may purchase power on hubs other than the Mid-C. Staff encourages PacifiCorp to develop a market-based pricing option, however.

PacifiCorp advocates continuation of existing volumetric pricing, but does not oppose Staff's market methods. PacifiCorp points out, however, that in the interest of fairness and administrative ease, it would be appropriate to allow QFs of all sizes to select among the same set of pricing options. PacifiCorp also contends that each utility should select which natural gas index to use, based on that utility's system characteristics. PacifiCorp states that Opal is the appropriate index for it to use, as most of its gas resources that are not constrained are located in the Desert Southwest.

Idaho Power indicates that it could apply Staff's market pricing structures to the SAR methodology and, therefore, does not oppose Staff's proposal. Idaho Power raises concerns with PGE's proposed Mid-C pricing structure, however, noting the difficulty in implementing an hourly index price option.

ODOE expresses concerns that the Deadband Method may hinder a QF's ability to obtain adequate project financing because lenders will evaluate projected revenues of the proposed facility based on floor prices. Should the Commission adopt the Deadband Method, ODOE suggests that the Commission also adopt a twenty-year maximum term for standard contracts to offset any financing disadvantage caused by the Deadband Method.

Weyerhaeuser agrees that two pricing options, a fixed price option and a natural gas indexed price, should be implemented, but argued both options should be available to QFs of all sizes. Weyerhaeuser also cautioned against Staff's proposed Deadband Method. Calling the proposed floor and ceiling artificial, Weyerhaeuser advises that they would create additional risks either for QFs or for ratepayers, depending on market activity. Weyerhaeuser argues that caps and floors on natural gas indices are not needed because utilities can obtain the same by hedging against gas market swings.

ICNU indicates that as an overriding principle, QF pricing structures should provide predictability and allow a potential developer or investor to easily evaluate the economic feasibility of a project. ICNU also asserts that pricing options should be universally available to QFs.

2. Resolution

We conclude that the adoption of more pricing options for QF standard contracts is consistent with our goal, in this proceeding, to more accurately value avoided costs. Recognizing that a QF is in the best position to select a pricing option that best suits its operations, and agreeing with PacifiCorp and ICNU that fairness and administrative ease call for all eligible QFs to have the same set of pricing options, we do not adopt Staff's proposed limitations on the availability of certain pricing options. Instead, we adopt four pricing options for PGE and three pricing options for PacifiCorp and Idaho Power, with no qualifications regarding the ability of an eligible QF to choose among these options.

All three electric utilities shall offer the same three pricing options, as follows: (1) the Fixed Price Method; (2) the Deadband Method; and (3) the Gas Market Method. We adopt each of these methodologies, as defined by Staff. We delegate implementation decisions to each utility but direct each utility to work with Staff, as appropriate, to develop implementation tariffs and standard contract rates, terms and conditions. For example, each utility may designate the natural gas index to be used to implement the Deadband Method. Although PacifiCorp indicates that it set forth an implementation plan for each of Staff's proposed pricing methodologies and asks us for approval of this plan, it is not clear that other parties had a full and adequate opportunity to respond in full. Consequently, we decline to approve PacifiCorp's implementation plan at this time. The tariffs and standard contract forms of all three electric utilities should provide information about implementation of the adopted pricing methodologies. We will evaluate each utility's implementation of the pricing methodology in the proper forum.

For PGE, we also adopt its proposed Mid-C Index Rate Option. Neither PacifiCorp nor Idaho Power proposed a market indexed pricing option and we do not direct either to implement one at this time. Idaho Power raised concerns about whether its effort to develop an indexed pricing option would be too great to be warranted, and we acknowledge that the effort required to develop an indexed pricing option for Idaho Power may be vastly greater than potential benefits to QFs in Idaho Power's service territory that would be likely to select an indexed pricing option. Consequently, we leave it to Idaho Power's discretion whether or not to pursue development of an indexed pricing option. We direct PacifiCorp, however, to work with Staff to evaluate whether it would be appropriate to develop an indexed pricing option and encourage either Staff or PacifiCorp to offer an indexed pricing option for PacifiCorp in the second phase of this proceeding.

Only the Deadband Method was the subject of any concern or criticism by the parties. ODOE's concerns about effects on financing are overcome, however, by our decision to allow all QFs eligible for standard contracts to choose any of the options. A QF project that is concerned that the Deadband Method may hinder financing options is free to select a different pricing methodology. Although we acknowledge the risk posed by the Deadband Method of price swings above and below the methodology's ceiling and floor, we deem it important to make a market pricing option available to QFs that provides a sufficient revenue stream to attract financing. The Gas Market Method and PGE's fully indexed pricing option will provide useful counter examples for comparison purposes. We advise parties that it may be appropriate to further consider market pricing options in the second phase of this proceeding.

G. FORECASTING NATURAL GAS PRICES

1. Parties' Positions

With regard to implementation of its proposed pricing structure, Staff recommends that each utility specify in its avoided cost filing the hub, or combination of hubs, used to forecast natural gas market prices. Staff also recommends that each utility specify the published natural gas prices index that it will use to determine QF rates under the Deadband and Gas Market Methods.

ODOE disagrees, asserting that natural gas forecasts should be consistent among the utilities. ODOE is concerned that utilities have an incentive to underestimate natural gas forecasts in order to reduce avoided cost rates. Moreover, ODOE contends that evidence did not show that wholesale natural gas prices for the various Northwest hubs would vary among utilities, with the exception of small differences for transportation costs. For the purpose of setting avoided costs, ODOE claims that the only substantive difference in natural gas costs among Oregon utilities should be the mix of hubs used, and the weighting of each hub. ODOE recommends adopting methods to ensure consistency among utility price forecasts, including preparation by Staff of twenty-year natural gas price forecasts for the three local hubs to be reviewed in a contested case proceeding every two years. Sherman County and Simplot concur that a single, transparent forecast prepared by a neutral third party should be used.

Staff counters that consistency between a utility's calculation of avoided costs and its actual resource decisions is more important than consistency among the utilities' price forecasts. Staff observes that utilities have different views on future natural gas prices and that a utility's particular view influences that utility's resource planning decisions. Staff concludes, therefore, that "the principle of 'consistency' is best advanced by continuing to review avoided costs using the utility's view of prices because those prices are consistent with the utility's actual resource decisions."[56]

ODOE also expresses a concern that the current avoided cost filing process does not provide parties with a sufficient opportunity to review and challenge utilities' gas price forecasts. Staff disagrees, explaining that a utility files its avoided costs as a proposed tariff, giving ODOE or any party an opportunity to request a suspension of the tariff with full process available to investigate the reasonableness of the filing.

ODOE also takes issue with PacifiCorp's exclusive use of the Opal gas price index to calculate avoided costs. ODOE argues that it is inappropriate for PacifiCorp to match its western control area load resource balance with eastern control area gas prices, particularly since PacifiCorp is likely to site its next power plant in the eastern control area.

2. Resolution

We decline to require the use of a single natural gas forecast to set avoided costs rates. As Staff notes, utilities have differing views on future natural gas prices and, consequently, there could be legitimate variations among utility forecasts. Moreover, the continued review of avoided costs based on each utility's view of prices is consistent with each utility's actual resource decisions.

We do not share ODOE's concern about the inability to review and challenge a utility's gas price forecast. Avoided cost filings are subject to suspension and the same investigatory process that any tariff filing may undergo. Natural gas forecasts that utilities use in avoided cost filings are, therefore, also subject to investigation and full review. We encourage ODOE and other interested parties to seek suspension of an

[56] Staff 700 at 2-3.

avoided cost filing when necessary to address concerns about natural gas forecasts, or any other aspect of a utility's filing. Indeed, an issue that would be appropriate to raise in an avoided cost proceeding is PacifiCorp's exclusive use of the Opal index to forecast natural gas prices. In any future examination, Staff or another party may introduce an independent natural gas forecast for comparison.

H. COSTS INCURRED DUE TO NATURAL GAS PRICE VOLATILITY

1. Parties' Positions

PacifiCorp represents that the proposed indexed pricing options will place greater risks on electric utilities. Because customer rates are established in general rate cases based on normalized conditions, PacifiCorp explains that utilities bear the risk between rate cases for any deviation between projected and actual costs. PacifiCorp argues that indexed pricing guarantees that costs will deviate from projected costs, thereby significantly increasing utilities' risk should a considerable volume of QF generation be indexed to gas.

PacifiCorp recommends that utilities' risk be mitigated and proposes that a mechanism, such as deferred accounting or a power cost adjustment (PCA), be implemented to allow utilities to recover costs associated with natural gas volatility. PacifiCorp also asserts that electric utilities should be able to recover any hedging costs that are prudently incurred in connection with indexed QF power purchase costs.

Staff counters that utilities recover fuel costs for utility-owned generation based on expected future gas prices, yet pay for fuel based on actual market prices. Staff observes that recovery risk for indexed rates should, therefore, be no different than recovery of utility-owned generation costs. Staff also points out that utilities have the ability to hedge against natural gas volatility. Staff indicates that it would be appropriate to consider recovery of a utility's prudently incurred hedging costs in a general rate case, so long as both the associated benefits and costs are reflected in test year revenue requirements.

ICNU opposes the use of deferred accounting or a PCA mechanism for recovery of costs associated with utilities' exposure to natural gas volatility due to indexed pricing. ICNU asserts that deferral of costs should be approved only under extraordinary circumstances and that institution of a PCA is justified only if a utility is actually facing and incurring costs associated with market volatility. ICNU opines that PacifiCorp has failed to demonstrate such conditions. ICNU also observes that the use of either mechanism should only be considered in conjunction with evaluation of a utility's cost of capital, and contemplation of whether a utility's authorized cost of capital should be lowered to reflect a reduction in the amount of risk the utility faces. Finally, ICNU asserts that it is outside the scope of this docket to address the use of deferred accounting or a PCA to recover natural gas volatility costs that utilities may incur due to indexed pricing. ICNU and Weyerhaeuser support utilities' use of hedging tools to address natural gas volatility and do not object to the recovery of hedging costs.

2. Resolution

We are not persuaded that it is appropriate to handle cost recovery for indexed QF payments differently than cost recovery for other energy resources. Staff's analogy to cost recovery for utility generation is an appropriate one and informs our decision. We also conclude that PacifiCorp has failed to adequately distinguish the risks associated with recovery of indexed QF payments.

To the extent that utilities desire to generally address risk mitigation methods, we advise utilities to raise such issues in dockets better suited to this discussion. For example, a proposed PCA mechanism would be best addressed as part of a general rate case proceeding. We also remind parties that a decision in Docket No. UM 1147 regarding our deferred accounting policies is currently pending and will eventually govern all applications for deferred accounting.

Hedging tools are financial instruments that can be used to reduce the risk of price volatility in certain markets. We have previously addressed the use of hedging tools to address volatility in natural gas markets in Order No. 99-272. The use of hedging instruments to mitigate risks associated with contracts that pay QFs indexed prices and the recovery of hedging costs incurred by utilities to mitigate QF contract risks were appropriately raised as issues in this proceeding. We find that such issues should be fully considered, but we do not find that a record has been sufficiently developed to allow us to do so in this order. Consequently, we direct parties to raise the issues again in the appropriate dockets, such as a general rate case or a proceeding that addresses PGE's resource valuation mechanism.

I. PRICING ADJUSTMENTS FOR STANDARD CONTRACTS

1. Parties' Positions

Perhaps in anticipation that standard rates may be made available to QFs with design capacities larger than the threshold limits that they proposed, PacifiCorp and PGE recommend that the Commission allow some standard contract pricing flexibility for certain project-specific characteristics. PacifiCorp notes that Staff agrees that parties to a standard contract may negotiate term variations. PacifiCorp recommends, however, that utilities be allowed to impose certain pricing adjustments in order to address issues that might include integration costs, debt imputation, or commercial and operational costs associated with intermittent QF resources.

Staff counters that the characteristics of a specific QF may impose costs greater or lesser than costs captured by the standard contract rate, but notes that on balance, the standard contract rate is deemed to provide a fair rate to QFs eligible to receive it. Staff observes that the ability of utilities to impose pricing adjustments would undermine the transparency, simplicity, timeliness and economy of a standard contracting process.

2. Resolution

In this order, we establish standard contract rates, terms and conditions that incorporate sufficient flexibility to address QF project-specific characteristics that we have deemed it appropriate to address. For example, the pricing structure we have adopted allows certain QFs to select a pricing option suitable to fuel and risk characteristics of the facility. As another example, QF pricing provides differentiation on a seasonal, as well as peak and off-peak basis. We believe further flexibility in negotiating the terms of a standard contract would fundamentally undermine the purposes and advantages of standard contracts and, therefore, deny the request by PacifiCorp and PGE for additional pricing flexibility.

Standard contracts are designed to minimize the need for parties to engage in contract negotiations. Consequently, any flexibility in the terms and conditions of a standard contract should be specifically delineated and bounded. To the extent that a party anticipated the need for flexibility with regard to a particular standard contract term or condition, the specific issue should have been raised and examined in this proceeding. It is inappropriate to request that standard contracts be subject to potential negotiation to address project-specific characteristics. In any case, we note that certain issues, such as integration costs, will likely be taken up during the second phase of this investigation when interconnection procedures and agreements will be addressed.

J. DETERMINING ELIGIBILITY TO RECEIVE A STANDARD CONTRACT

1. Parties' Positions

To be eligible to receive a standard contract, a QF must be sized at or under the 10 MW threshold we have established herein. Parties raised an issue in this proceeding regarding how the threshold is defined with regard to measuring QF eligibility. Staff recommends basing QF eligibility for standard contracts on the manufacturer's nameplate capacity for a particular facility. Staff maintains that nameplate capacity provides a clear standard that is not subject to manipulation. Staff also argues that, over the course of a year, a QF's average output will align with its nameplate rating. ICNU concurs with Staff's position, asserting that QFs may operationally fluctuate over the course of a year, but on average produce energy below the nameplate capacity.

Idaho Power contends the issue is more complicated and recommends that an alternative approach. Idaho Power also disagrees with Staff, asserting that nameplate capacity is subject to manipulation. Idaho Power initially recommended a metered energy test be applied on an hourly basis. Under this methodology, standard contract rates, terms and conditions would not apply to metered energy delivered in any month that exceeded 10,000 kWh per hour. Idaho Power ultimately recommends adoption of the monthly metered energy standard instituted by the Idaho Commission, which established a two-part test to determine QF eligibility for standard contracts.[57] A QF developer must initially provide evidence that, under normal or average design conditions, a QF project will not generate more than the threshold amount on a monthly average basis. Energy delivered is then metered on a monthly basis, and standard contract rates are not paid for any energy delivered in excess of the monthly threshold. PacifiCorp supports adoption of either an hourly or monthly metered energy test with a cap on standard contract payments, combined with requiring a QF developer to represent that a particular project does not exceed the threshold.

During cross examination of Staff's witnesses, Weyerhaeuser raised another question, asking whether a QF with a nameplate capacity greater than the size threshold for standard contract eligibility could agree to sell an amount of power equal to, or lower than, the threshold in order to qualify for standard contract terms. Staff argues no. Asserting that standard contracts are offered as a means to overcome transactional barriers experienced by QFs deemed to be disadvantaged, Staff reasons that QFs larger than the threshold size are capable of negotiating a contract and should not be eligible in any way for standard contract terms.

2. Resolution

Design capacity was established as the criterion for standard contract eligibility in Order No. 81-319. We deem the evidence introduced in this proceeding insufficient to justify imposing a different standard at this time.

Design capacity, as defined by the manufacturer's nameplate capacity for a QF project, will continue to be the measure of eligibility for standard contracts. In order to be eligible to receive standard contract terms and conditions, a QF must have a manufacturer's nameplate capacity at or under 10 MW. If a QF's nameplate capacity is greater than 10 MW, the QF is ineligible to receive a standard contract and cannot agree to operate at a lower threshold level in order to qualify for a standard contract.

As we have emphasized in this Order, the purpose of standard contracts is to eliminate negotiations for QF projects for which they would be economically prohibitive. We have determined that QF projects larger in size than 10 MW have the financial resources to engage in QF purchase contract negotiations despite the hurdles posed by market barriers that they face. Consequently, we do not discern any justification for permitting a QF with a nameplate capacity larger than 10 MW to reduce operations to 10 MW or less in order to receive standard contract terms and conditions.

Although significant evidence may have been presented to the Idaho Commission that conclusively established the inappropriateness of using the manufacturer's nameplate capacity, the bulk of any such evidence was not presented in this proceeding. We cannot make a decision based upon evidence that did not receive full examination and vetting in this docket. To the extent parties wish to introduce

[57] IPUC Order No. 29632, in Case No. IPC-E-04-8/IPC-E-04-10.

additional evidence on this issue, they are invited to do so in the second phase of this proceeding.

K. STANDARD CONTRACT FORM

1. Parties' Positions

Two parties recommend that we adopt model standard contracts created or approved by an independent organization or another state public utility commission. FRC recommends that the Commission adopt a model standard contract endorsed by the National Association of Regulatory Utility Commissioners (NARUC), while Weyerhaeuser suggests that the Edison Electric Institute (EEI) Master Agreement or standard contract forms approved by the California Public Utilities Commission be used to draft default standards for non-rate terms and conditions.[58]

Staff and three other parties recommend that each utility draft its own standard contract within the framework that we adopt in this order. PacifiCorp indicates that it currently has three separate standard contract forms: one form addresses projects up to 100 kW, another addresses projects up to 1 MW and a third addresses projects over 1 MW. Although the terms of the three contracts are similar, selected terms vary to address particular characteristics of projects of a certain size. PacifiCorp states that additional contract forms may be necessary should the Commission adopt pricing options and recommends that the Commission allow flexibility in the form and number of standard contracts. Observing that it is consistency across the utilities on essential contract terms that matters, not variations on non-essential terms, Sherman County and Simplot agree with PacifiCorp that each utility should draft compliant standard contract forms. Staff recommends that each utility file standard contract forms with the Commission for approval, and advises that approved forms should be made publicly available in the same manner as tariffs.

2. Resolution

For reasons presented by Sherman County, Simplot, and PacifiCorp, we decline to adopt a model standard contract form and agree that each utility should draft its own standard contract rates, terms and conditions. We therefore direct the electric utilities to draft and file one or more standard contract forms as necessary to comply with our decisions in this order. Standard contract forms should accompany revised tariffs. We direct utilities to file standard contract forms with revised tariffs within sixty days of this order. We expect each standard contract form to contain terms and conditions that are consistent with the resolution of issues in this order or past orders, as appropriate. It is not necessary, however, that particular terms be identically worded across all standard contract forms, so long as the meaning of each term is consistent with the present or past decisions. We expect that terms that are not specifically discussed in this order or past orders will vary among the utilities. Staff will review each standard contract form and work with each utility to ensure the compliance of submitted standard contract forms.

[58] Weyerhaeuser submitted a California Standard Offer No. 1 QF Contract as Exhibit 102.

Filed standard contract forms will be subject to the same suspension and approval process as tariffs.

L. SECURITY, CONSTRUCTION CREDIT, INSURANCE AND INDEMNITY REQUIREMENTS

1. Overview

The parties engaged in significant discussion regarding what terms should be included in standard contracts to address a variety of recognized contractual risks. Recognized risks include the timely construction of a QF project and its online availability by the start of scheduled power deliveries, the failure of a QF to provide promised power due to operational interruption, and third-party liabilities arising from a QF accident or failure. Although interconnected in many ways, each risk must be separately addressed.

2. Default Terms

a. Overview

Under a standard contract, a QF agrees to provide a certain amount of power to a utility in exchange for payment of avoided cost rates. After the QF project is operational, there are a number of reasons why a QF might not deliver the promised amount of power, including weather-related reductions in resource availability, operating problems which may be extended due to vendor repair problems, mismanagement, or bankruptcy. Parties debate whether it is necessary to include terms and conditions in standard contracts that delineate what constitutes a default and provide for compensation to the utility in the event that costs are incurred to replace the QF power.

Standard contracts currently require QFs to demonstrate creditworthiness, or to make a specified amount of funding available to the utility party as "default security." The default security would typically be in the form of a letter of credit or a cash escrow that could be used as reimbursement in the event the QF defaults after it begins operation. Only PacifiCorp provided detailed information about current security requirements in standard contracts.

To demonstrate creditworthiness to PacifiCorp, a QF with a design capacity up 99 kW in size must make a series of representations and warranties, including that it is current on debt repayment and has not been a debtor in a bankruptcy proceeding. A QF that is sized between 100 kW and 999 kW must provide evidence of operating history for five years, or meet a financial test and have no material change in financial condition in the past two years. A QF with a design capacity greater than 1,000 kW must meet a published credit rating test.

Sample standard contract forms filed as part of the utilities' informational filings in this proceeding did not specify the amount of required default security that is typically required. PacifiCorp states that its credit and security requirements are currently being further developed, but represents that a 4.95 MW project would be required to submit default security in an amount that would cover PacifiCorp's replacement power costs for twelve months. Default security would have a floor amount equal to three months of average monthly output times an average purchase price, or three months of average monthly payments by PacifiCorp. PacifiCorp also imposes annual and lifetime caps and adjusts default security requirements on an annual basis. If a QF provides non-firm power on an as-delivered basis and does not receive capacity payments, PacifiCorp does not require default security.

b. Parties' Positions

In the absence of other documentation, Staff considers the default security term of a generic power purchase agreement form, which accompanied a request for proposals by PacifiCorp for renewable resources, to be representative of the amount of default security that may be required by a utility of QF projects that have a design capacity of 1 MW or more. The power purchase agreement specified an amount equal to the positive difference between the contract purchase price and the result of 110 percent of forward power prices at the appropriate market hub for the next 18 months, multiplied by the estimated monthly outputs under the contract. Staff notes that Idaho Power indicated it would likely use the amount of energy expected to be provided under the contract for two years multiplied by the price per MWh that is specified for the first contract year.

Staff is concerned about this level of default security requirements, and questions whether a small QF will be able to obtain and make available the level of security required, particularly in the form of a letter of credit. As a result, Staff is ultimately concerned that utilities' default security requirements will hamper QF development. Rather than require a letter of credit or escrow deposit, Staff recommends that standard contracts specify that, in the event of default, should market prices exceed the QF contract price during the default period, future payments that are resumed after the end of the default period would be commensurately reduced over a reasonable time period.

In the event that levelized rates are authorized for QFs, Staff recognizes the need for default security requirements beyond a contractual term that would reduce future payments. Staff acknowledges that levelized payments would subject the utility and its ratepayers to overpaying the QF in the early years of the contract should the QF breach the contract in later years. Should a QF receive levelized payments, Staff recommends that the utility allow the QF to select one of the following default security measures: credit rating requirements; a senior lien on the facility; step-in rights; a cash escrow; or a letter of contract. Staff also takes the position that default should not be triggered by weather-related conditions for QF projects that use natural motive force for generation.

ODOE indicates that as risks arising from potential QF default are small, default security is not warranted. Any benefits that might be provided by default security in standard contracts would be outweighed by the barriers to QF development imposed by the requirements. ODOE agrees, however, that default security is warranted if payments are levelized. ODOE acknowledges that, over the course of a contract with levelized payments, there will be a certain period during which the QF will be paid in excess of the fixed year-to-year contract price. ODOE asserts that the associated risks can be quantified by comparing revenue streams under a levelized and non-levelized contract. ODOE states that it is appropriate to require default security in the amount of the difference between the two revenue streams. The amount of security required could be calculated at the inception of the contract on a year-by-year basis. ODOE recommends that the total amount of security required be limited, however, to "around 2% of the capital cost of the project."[59] ODOE further qualifies that it might be appropriate to scale this cap based on the type of QF technology. ODOE suggests that QFs be able to choose between a non-levelized rate with no default security requirements and a level rate with a known level of default security required. A letter of credit should not be required as they are typically too difficult and expensive for a smaller QF to obtain.

PacifiCorp asserts that to ensure the indifference of ratepayers between QF power and other sources of electric power, the risks of QF development and operation need to be considered. Consequently, PacifiCorp argues that it is appropriate to require that a QF demonstrate creditworthiness, or alternatively to provide credit assurance in the amount of the anticipated replacement cost of QF power. Replacement cost is measured as the difference between the contract price and the expected market price.

For QFs smaller than 3 MW, however, PacifiCorp is willing to modify its existing requirements. PacifiCorp would allow a QF that is 3 MW or less to establish creditworthiness by making a set of representations and warranties that would include an affirmative statement that the QF is current on its financial obligations and that it has not been a debtor in a bankruptcy proceeding within the past two years. PacifiCorp will not require default security from any QF that is sized at 3 MW or less. In the event of default, to the extent PacifiCorp incurs replacement costs greater than the contract price, PacifiCorp will recoup the difference from future payments. PacifiCorp suggests implementation of a reasonable cap on the amount that can be recouped from future payments, however.

c. Resolution

Pursuant to the rates, terms and conditions that we adopt in this order, standard contracts for the purchase of electric power from QFs will be long term, must-take contracts with significant revenue impacts. Contracts of this scope and nature, regardless of their subject matter, typically impose some level of security requirements on one or more of the parties. Although ODOE represents that risks arising from potential default by a QF are likely small, ODOE does not quantify the risk. Indeed, no party provides any empirical evidence of the risks associated with QF default.

[59] ODOE 3 at 6.

In the absence of such evidence, we conclude that it would not be prudent to subject utilities and, in turn, their ratepayers, to an unknown level of unsecured risk. We agree, however, that the risk may be relatively low and that an unreasonably high level of security may create a major impediment to the development of QF projects. Consequently, the question is not whether to require *any* default security, but rather what level of default security requirements should be required?

We are persuaded that all QFs should be required to establish creditworthiness by making a set of representations and warranties that the QF has good credit, including that it is current on existing debt obligations and has not been a debtor in a bankruptcy proceeding within the preceding two years. Requiring a party to a contract to enter the contract with good credit is a reasonable and prudent requirement.

Although PacifiCorp recommends that QFs with a design capacity of 3 MW or less be required to establish creditworthiness by making a set of representations and warranties that the QF has good credit, PacifiCorp did not indicate any recourse if the QF could not, in good faith, make such representations and warranties. We conclude, however, that in the event that a QF cannot demonstrate creditworthiness, the QF should be required, regardless of its size, to provide some default security. In the absence of an applicable proposal, we adopt Staff's proposal that requires a QF unable to satisfy credit rating requirements to provide a reasonable amount of default security by one of the following means, selected at the QF's discretion: senior lien, step-in rights, a cash escrow or a line of credit. As parties did not address the proper amount of default security, we decline to impose any requirements at this time and leave this determination to the discretion of each utility, subject to Commission review of the standard contract provision implementing the amount. We direct parties to further address the appropriate amount of default security in the event that a QF cannot demonstrate creditworthiness in the second phase of this proceeding.

Should a QF demonstrate creditworthiness, we conclude that some provision for default security in the event that it is needed is appropriate. In balancing the goals of facilitating QF contracts while sufficiently protecting ratepayers, we recognize that the primary aim is to ensure that ratepayers remain indifferent to the source of power that serves them. Although default security provided in the form of a letter of credit or escrow deposit provides immediate recovery of costs incurred due to a QF's default, we are persuaded that terms providing for future recovery over the course of a long term contract are reasonable. Consequently, we adopt Staff's recommendation that standard contracts include a clause providing that, in the event that a QF defaults and the market prices to replace the contracted for energy exceed the contract price, future payments after the default period ends shall be commensurately reduced over a reasonable period of time to recoup the costs incurred by the utilities. Although PacifiCorp proposed a reasonable cap on the amount that can be recouped, PacifiCorp provided no further detail. As no evidence was presented regarding the appropriate size of such a cap, nor any evidence about alternate provisions, we decline to impose any requirements. Instead, we encourage PacifiCorp to raise this issue in the second phase of this proceeding.

3. Construction Credit

a. Overview

A standard contract for a QF project under development will typically specify an operational date for the QF. On that date, the parties anticipate the QF will begin power deliveries for which it will be compensated. Construction delays may interfere with the timely completion and start-up of a QF project. Parties debate whether construction delays may result in compensable harm to the utility and its ratepayers should the anticipated QF power need to be replaced with higher priced power.

Standard contracts typically require QFs to provide "project development security" in the form of a letter of credit or a deposit in escrow for a specified amount. The intent is to provide funds that the utility party can draw upon should a construction delay occur that postpones the commercial operation of the QF.

b. Parties' Positions

Again, Staff considers the project development security term of a generic power purchase agreement form, which accompanied a request for proposals by PacifiCorp for renewable resources, to be representative of the amount of project security likely to be required of QF projects over 1 MW. The power purchase agreement specifies an amount equal to the result of the amount of energy expected to be provided under the contract for a period of two years, multiplied by the price per MWh that is specified for the first contract year.

Rather than requiring a QF to provide a letter of credit or an escrow deposit during construction, Staff recommends that utilities require a QF to provide a construction or performance bond. Staff indicates that a bond required by a financing company would suffice. Staff asserts that such a bond will provide about the same protection to the utility as a letter of credit or escrow deposit would, but at a more affordable cost.

ODOE represents that it is standard financing practice to require a performance and payment bond during construction to insure funding to complete the project. Such bonds do not require completion of the project by the anticipated date, however, and do not provide funds to third parties that may rely on the project beginning operation. Nevertheless, ODOE recommends against allowing utilities to require an additional performance bond.

PacifiCorp indicates that it would consider allowing performance bonds to be used to provide project development security if they are shown to provide the same safeguards as traditional forms of security.

c. **Resolution**

As an agency experienced with financing of QF projects, ODOE persuades us that financing companies require appropriate security to ensure that a QF project is fully developed. Consequently, we conclude that the issue before us is not what level of security is needed should a contracted QF project never be operational. Rather, the issue we must consider is what security is needed should a contracted QF project be delayed in coming on line?

This situation is effectively no different than a default situation. In both situations, the utility may need to replace the contracted for energy at market prices that may exceed the contract price. The only difference with regard to construction default or delay will be that replacement will occur not far in advance of the date of contract implementation.

At the time the contract is signed, we would expect parties to be aware of whether the contracting utility is in a resource deficient or sufficient position. We observe that if a utility is in a resource sufficient position, the contracted-for energy will likely not need to be immediately replaced. Consequently, we do not discern any reason to require additional security requirements in such a situation. If the utility is in a resource deficient position, however, it is more likely that the utility will need to replace the contracted for energy. Such a situation should be able to be addressed, however, with the same security requirements imposed in a general default situation. Although Staff proposes the use of a performance bond to address construction delays, evidence was inconclusive as to the availability and effectiveness of such instruments to address costs to third parties. We find that it would be more appropriate, in the event of construction default or delay, to impose the same default security requirements that we have already authorized in the event of default or delay after a QF facility is operational.[60] We direct the electric utilities to draft construction default provisions that are consistent with these default security provisions.

4. **Indemnity and Liability Insurance Requirements**

a. **Overview**

QF standard contracts usually require all QFs, regardless of size, to indemnify utilities and to carry various types of liability insurance in varying amounts. They also may require the QF to name the utility as an additional insured on the QF's policies. A primary purpose of these insurance requirements, in conjunction with an indemnity clause, is to pay for litigation and judgment costs arising out of any lawsuit that is instituted against a QF based on its operations.

[60] *See discussion*, page 45.

b. Parties' Positions

FRC members testified that utilities' insurance requirements are new—relative to existing standard contracts signed many years ago—and act as a significant impediment to development of small QF projects because insurance is difficult and expensive to obtain and maintain.[61] For example, testimony by Mr. Steve Sanders, the proprietor and operator of Minikahda Hydropower Co. LLC, indicated that the insurer for his construction business is unable to provide a one million dollar liability policy for his QF operations for less than $10,000 a year. Ms. Toni Roush, proprietor and operator of Roush Hydro, testified that although she was aware of one insurance carrier that would underwrite an affordable insurance policy for QFs, most insurance providers did not have sufficient familiarity with the risks associated with small QF operation to offer an affordable policy. Other FRC members characterized insurance simply as an unknown cost.

In response to past complaints from QFs that the insurance requirements are onerous and unfair, Staff recommends that standard contracts not impose any insurance requirements on QFs. Although Staff supports the inclusion of indemnity clauses in standard contracts and considers it prudent for QFs to carry liability insurance, Staff takes the position that the QF, not the utility, should determine the type and level of insurance to be carried. Staff is concerned that the insurance terms required by utilities impose greater cost than is necessary to obtain satisfactory insurance. Moreover, given no past record of any event that required a QF to rely on insurance, Staff perceives the risk to be low that insurance of the type and level currently required by utilities would be necessary. Consequently, Staff contends that the potential harm to ratepayers caused by a QF carrying inadequate insurance is too small to justify imposing insurance requirements deemed sufficient by the utilities.

Staff also observes that insurance is often not mandated for other types of contracts between utilities and small energy providers. For example, NARUC has recently published a model interconnection agreement that does not contain mandatory insurance requirements, and Staff states that eighteen states do not mandate insurance coverage for QFs interconnecting with utilities.[62] Staff also notes that the Oregon net metering law prohibits utilities from imposing insurance requirements.[63] Staff would support inclusion of language in QF standard contracts that is similar to that contained in the net metering statute.

PacifiCorp asserts that indemnity clauses and insurance coverage are complementary and should be mutually included in QF contracts. PacifiCorp states that absent insurance coverage, QFs may lack the financial resources to satisfy indemnity obligations which subjects ratepayers to inappropriate risk. Observing that the risks of

[61] FRC members indicate that utilities did not require insurance when they originally entered into QF contracts. Upon renewal of these contracts, however, utilities are seeking to impose insurance requirements.

[62] Staff 100 at 10-11, citing the Interstate Renewable Energy Council's ("IREC") "Interconnection Regulations for Non-Net-Metered Distribution Generation" (June 2004).

[63] *See* ORS 757.300(4)(a)-(c).

interconnection between a utility and a QF include fire, electrical surges and electrocution, PacifiCorp argues that the level of risk exposure is not commensurate with QF size and that the potentially smaller financial resources of small QFs render them less likely to be able to fulfill indemnity clauses without the aid of insurance. Indeed, PacifiCorp observes that if a small QF cannot afford liability insurance, it will not be able to afford litigation and judgment costs arising from a lawsuit. Nevertheless, PacifiCorp opines that should the Commission exempt QFs from carrying insurance, the exemption should only apply to very small QFs with capacities at 100 kW or under, and the Commission should specify that utilities may recover costs arising out of lawsuits directed against uninsured QFs.

To the extent QFs are required to carry insurance, PacifiCorp argues that utilities should mandate the level of insurance required in order to assure consistency among QFs. PacifiCorp indicates that it is willing to work with QFs to obtain satisfactory insurance options. PacifiCorp also observes that insurance requirements imposed on QFs are not discriminatory, as PacifiCorp requires liability insurance to be carried by all vendors with which it contracts. Moreover, PacifiCorp notes that Oregon typically requires vendors with which it contracts to carry sufficient insurance.

PacifiCorp considers the NARUC model interconnection agreement to be inadequate. In any case, PacifiCorp observes that the NARUC model is not pertinent to QF power purchase contracts. Moreover, PacifiCorp points out that the model agreement may be outdated based on November 2004 filings in a FERC docket addressing the standardization of small generator interconnection procedures. In that proceeding, PacifiCorp represents, NARUC and other parties submitted a consensus proposal that requires insurance for small interconnected generators.[64]

PacifiCorp also takes issue with Staff's assertion that eighteen states prevent utilities from requiring QFs to carry insurance. In the first place, PacifiCorp argues that Staff's assertion is based on a document that pertains to interconnection agreements, not QF power purchase contracts. Second, PacifiCorp contends that the document at issue actually only discusses eighteen states that have conclusively resolved the issue of insurance, with seven of those states requiring some form of insurance. PacifiCorp asserts that it reviewed a different IREC publication that indicates most utilities require liability insurance to be carried by interconnecting distributed generation facilities. Similarly, PacifiCorp points out that Oregon's net metering statute applies to net metering projects that are 25 kW or less in size and that the statutory language would provide little security against third-party lawsuits against utilities for QF conduct.

Idaho Power urges the Commission to allow utilities to require that QFs carry proper liability insurance as the Idaho Commission has done. The Idaho Commission has considered appropriate liability insurance requirements twice, concluding both times that QFs should carry insurance.[65] Idaho Power states that in

[64] Reply Brief of PacifiCorp at 10, citing "Second Interim Report of Coalition of Parties Seeking Consensus on Small Generator Interconnection Issues," Docket No. RM-02-12-000 (Nov. 22, 2004).
[65] Idaho Power 100 at 12-13, referring to Case No. U-1006-292 and Case No. IPC-E-03-16.

2003, the Idaho Commission concluded that Idaho Power's business insurance requirements, including the requirement that all QFs, regardless of size, carry general liability insurance, should be maintained with only minor changes. Idaho Power notes that 71 QFs have obtained liability insurance in Idaho, including numerous QFs smaller than 100 kW that carry the required one million dollars in insurance coverage. PGE points to experience in Idaho as evidence that insurance requirements do not impede QF development. Both Idaho Power and PGE maintain that ratepayers should not be forced to bear *any* risk for accidents or negligence resulting from QF operation and that insurance is an appropriate means to protect them. Should the Commission decline to grant utilities the authority to mandate insurance requirements, Idaho Power requests that any costs that arise out of QF litigation be strictly allocated to Oregon ratepayers. Staff opposes the allocation of a singular category of costs to one jurisdiction.

c. Resolution

Standard contracts typically include mutual indemnity clauses and no party contests the appropriateness of such terms. We affirm the appropriateness of including indemnity clauses in standard contracts. No party requested that we specify the wording of such clauses, and we discern no need to do so. We direct utilities to individually draft standard contract indemnity clauses.

We conclude that the issues of indemnity provisions and liability insurance requirements[66] are inextricably linked, as they share the common and complementary purpose of minimizing risks associated with the interconnection of a utility and QF. Indeed, we understand a primary role of general liability insurance to be to provide the resources necessary to fulfill promises that are made in an indemnity clause.

Most parties weighing in on the subject of liability insurance, including Staff, agree that it is prudent for all QFs to carry liability insurance. Nevertheless, the parties' discussion regarding appropriate liability insurance requirements focused primarily on the question of whether standard contracts should require QFs to carry *any* insurance, rather than on the alternate question, if insurance coverage is required, what kind, and how much, should be specified. With regard to the question of whether all QFs should be required to carry liability insurance, the parties' underlying concern seems to be, not whether it is necessary or prudent for QFs to carry some amount of liability insurance—again, most if not all parties agree that it is—but whether it is feasible, in terms of availability and cost, for certain QF projects to obtain and carry sufficient liability insurance.

We find it unfortunate that no party presented testimony from, or based on, the representations of an insurer. Idaho Power testified that all 71 QFs that have

[66] Although parties did not explicitly list the types of insurance at issue in this proceeding, we consider the discussion to be limited to property and general liability insurance that covers risks associated with interconnection of a utility and QF. We consider other types of insurance, such as workers' compensation, employer's liability and automobile insurance to be beyond the scope and purpose of insurance at issue in this proceeding.

entered into standard contracts in Idaho, regardless of the size of the QF, have obtained the required liability insurance. We have limited evidence about the scope of insurance requirements in standard contracts in Idaho, however, and we do not have any evidence about whether any QF in Idaho did not enter into a standard contract due to the level of required insurance. Consequently, we deem Idaho Power's testimony about the wide-spread availability of insurance to be of limited value. We also find the testimony about insurance requirements in standard contracts or interconnection agreements to be inconclusive. Moreover, we do not have any testimony from QFs larger than the very small QFs represented by FRC about their experiences obtaining liability insurance. Additionally, although some utilities expressed a willingness to work with QFs having difficulty obtaining liability insurance, we do not have any testimony from the utilities about the availability and cost of such insurance. Consequently, we only have the uncontested testimony of FRC members who testified that liability insurance is either not available, or is prohibitively difficult or expensive to obtain, for very small QFs operating in Oregon.

We must conclude, therefore, that it is inappropriate to require QFs that have a design capacity of 200 kW or less to be required to obtain general liability insurance. Nevertheless, we are not persuaded that the absence of past incidents requiring QFs to rely on liability insurance indicates that insurance will not be needed in the future and we reiterate our position that it is prudent for *every* QF to carry liability insurance. Consequently, we encourage QFs with a design capacity of 200 kW or less to pursue liability insurance on their own. We also encourage the electric utilities to work, in the coming months, with QFs that have a design capacity of 200 kW or less to determine whether reasonably priced general liability insurance is available. If the utilities find that such insurance is available, parties may raise the issue again in the second phase of this proceeding.

We direct the utilities to require all other QFs that sign standard contracts to obtain prudent amounts of general liability insurance. As parties did not raise the issue, we do not address the scope of general liability insurance considered prudent. Should this issue be of concern to any party, we encourage that party to raise it in the second phase of this proceeding.

We recognize that making an exception to general liability insurance requirements for QFs with a design capacity of 200 kW or less exposes utilities to some risk. No party presented any evidence, however, regarding the potential scope of such risk. In the absence of such evidence, we conclude that the risk is likely small and decline to make any conclusions, for Idaho Power or any other electric utility, about the need to pre-approve recovery of costs stemming from QF uninsured liability. Parties may further raise this issue, however, in the second phase of this proceeding.

IV. ISSUES OF GENERAL APPLICABILITY TO STANDARD AND NEGOTIATED QF CONTRACTS

A. SIMULTANEOUS PURCHASE AND SALE OPTION

1. Parties' Positions

One form of QF power is thermally-balanced combined heat and power (CHP) installations. Manufacturing facilities with installed CHP can supply energy for on-site manufacturing processes and under an existing QF contract—whether standard or custom—sell any excess power that is not needed to power the site, to a utility at the utility's avoided cost. Weyerhaeuser argues that CHP QFs should have more than one option for selling cogeneration power and requests the ability to sell the entire output from a CHP installation, less internal auxiliary use, to a utility at its avoided costs, with the host manufacturing facility's onsite load being fully served by the utility pursuant to a standard tariff. Weyerhaeuser labels this arrangement a "simultaneous purchase and sale option" and represents that FERC has approved it.[67]

Weyerhaeuser acknowledges that there should be some limitations on the ability of a CHP QF to elect to sell its entire generational output (net internal auxiliary use). Weyerhaeuser suggests that utilities may impose reasonable limitations on the frequency with which a QF is allowed to transfer between a simultaneous purchase and sale and the sale of surplus power only. Weyerhaeuser also recommends that CHP QFs be prohibited from switching between the two options more than one time a year. Moreover, Weyerhaeuser declares that a QF electing a simultaneous purchase and sale option must abide by the terms of service of the utility's sales tariff, and be required to pay for any additional metering needed to facilitate the simultaneous purchase and sale option.

PacifiCorp interprets Weyerhaeuser's proposal as a request to be able to alternate once a year between Schedule 47 (the full requirements tariff) and Schedule 36 (the partial requirements tariff), and raises practical and policy concerns with such an arrangement. From a practical standpoint, PacifiCorp represents that tariff rules would need to be modified to implement Weyerhaeuser's proposal, as current tariff rules require a customer to stay on either tariff for a period of five years before switching to another tariff. PacifiCorp also expresses concern that allowing QFs to alternate between options may be inappropriate from a policy perspective:

> The effect of Weyerhaeuser's proposal is to allow it to game (to the detriment of ratepayers) the difference between the Company's retail rates and the QF avoided cost rates. Basically, Weyerhaeuser wants firm prices

[67] Weyerhaeuser 100 at 12, citing *Connecticut Valley Electric Company, Inc. v. Federal Energy Regulatory Commission*, 208 F.3d 1037, 1040 (D.C. Cir. 2000), affirming *Connecticut Valley Electric Company, Inc. v. Wheelabrator Claremont Company, L.P. and Related Actions*, 82 FERC 61,116 (1998) and 83 FERC 61,136 (1998) (order denying rehearing).

> for generation that it will only put to the company when it is least valuable *and* a tariff entitlement to move its load on and off the grid without paying demand charges that reflect the cost to the Company of that optionality. Such proposal is inconsistent with the principle of ratepayer neutrality and should be rejected.[68]

Weyerhaeuser responds that its proposal should be accommodated according to existing tariff rules. Weyerhaeuser also argues ratepayers are indifferent to when QF power is sold to and purchased by a utility, as the power is sold at avoided cost.

2. Resolution

FERC precedent firmly establishes that a QF may sell no more than "net output" under PURPA.[69] "Net output" of a QF facility is defined by FERC as a facility's "send out after subtraction of the power used to operate auxiliary equipment in the facility necessary for power generation (such as pumps, blowers, fuel preparation machinery, exciters) and for other essential electricity uses in the facility from the gross generator output."[70] FERC has reaffirmed this limitation on several occasions and has refused to allow exceptions.[71]

Pursuant to FERC precedent, a QF may already sell the full net output of its facility, as opposed to surplus power only, to a utility. QFs are free to negotiate a net output sale that is consistent with FERC standards and with existing utility tariffs and rules. Standard contracts, on the other hand, currently provide only for a "surplus sale." Weyerhaeuser raises the question of whether standard contracts should also contemplate a "net output sale."

There was no discussion, however, from the parties about whether the avoided cost calculation requires modification to accurately reflect a "net output sale." As such, we do not believe there is sufficient evidence to warrant imposing a requirement that standard contracts offer a "simultaneous purchase and sale option." We observe, however, that many, if not most or all, CHP projects will be larger than the threshold we have designated for standard contracts. Consequently, most CHP QFs that desire a "simultaneous sale and purchase" arrangement will be required to negotiate a non-standard contract with a utility. We acknowledge that there may be hurdles to negotiating a "simultaneous sale and purchase" QF contract and encourage parties to

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[68] PPL 100 at 29.

[69] *See Occidental Geothermal, Inc.*, 17 F.E.R.C. ¶ 61,231 (1981); *Power Developers, Inc.*, 32 F.E.R.C. ¶ 61,101 (1985); and *Penntech Papers, Inc.*, 48 F.E.R.C. ¶ 61,120 (1989).

[70] *Occidental Geothermal, Inc.*, 17 F.E.R.C. ¶ 61, 444 (1981).

[71] *See Turner Falls Limited Partnership*, 53 F.E.R.C. ¶ 61,075 (1990) (denied request to waive "net output" standard for determining electric power production capacity of a QF); *Conn. Valley Electric Cooperative v. Wheelabrator Claremont Co. L.P., Carolina Power & Light Co. v. Stone Container Corp., and Niagra Mohawk Power Corp. v. Penntech Paper, Inc.*, 82 F.E.R.C. ¶ 61,116 (1998) (reiterated that a QF may not sell in excess of its net output); *Conn. Valley Electric Cooperative v. Wheelabrator Claremont Co. L.P., Carolina Power & Light Co. v. Stone Container Corp., and Niagra Mohawk Power Corp. v. Penntech Paper, Inc.*, 83 F.E.R.C. ¶ 61,136 (1998) (denies rehearing)

raise the issue of how to better facilitate "net output sales" in the second phase of this proceeding.

B. DISPUTE RESOLUTION

1. Overview

Pursuant to ORS 756.500, any person may file a formal complaint regarding the negotiation or enforcement of a QF contract. Unless a formal complaint is filed, the Commission does not intervene in negotiations or disputes between parties, other than to provide general information as requested. The Commission does not currently offer informal dispute resolution mechanisms.

2. Parties' Positions

Staff and two parties, PacifiCorp and PGE, comment on the proper role of the Commission in resolving disputes about QF contracts. All recommend that the Commission retain its current policy. Staff advises that the existing policy reduces real and perceived opportunities for Staff to be viewed as unobjective should a formal complaint be filed.

Although most parties did not directly address this issue, several parties comment that greater oversight of the non-standard contract negotiation process is needed. For example, as previously discussed, both Weyerhaeuser and ICNU call for greater guidelines regarding negotiation of non-standard QF contracts. PGE also suggests that concerns about negotiation of non-standard contracts could be addressed by improving the process and increasing its transparency.

3. Resolution

We have already concluded that certain market barriers impede the negotiation of non-standard contracts and have directed parties to develop, in a second phase of this proceeding, negotiation parameters and guidelines that would overcome these market barriers and facilitate negotiations. We understand, however, that even with better parameters and guidelines, disputes may arise during negotiation of a non-standard contract. We also understand that formal dispute mechanisms are not timely during contract negotiations. Consequently, we find that it is appropriate to reconsider whether Staff should have a role in the resolution of informal disputes.

As we explained in the Historical Background section of this order, the role of Staff in resolving QF disputes has varied over time. Staff currently does not participate in the informal resolution of QF contract disputes, due to concerns that such efforts would adversely affect Staff's objectivity, or the perception of Staff's objectivity, in formal disputes or rate cases.[72] We encourage parties to determine, in the second

[72] *See* "Report to the Sixty-Fifth Legislative Assembly and Energy Policy Review Committee," (November 1, 1988), p. 19.

phase of this proceeding, whether there is a role for Staff to play in the informal resolution of QF contract negotiation disputes that will not compromise Staff's objectivity in formal proceedings.

C. APPROVAL OF INDIVIDUAL QF CONTRACTS

1. Parties' Positions

Both PacifiCorp and Idaho Power argue that utilities should receive up-front assurances from the Commission that costs undertaken in a QF power purchase contract will be fully recovered and not subject to any disallowance. Both utilities contend that QF power purchase contracts are unique among other power purchase contracts. Idaho Power points to the fixed nature of standard contracts, while PacifiCorp observes that utilities do not make decisions regarding the location, timing, and cost effectiveness of QF power as they do for contracts for other resources. Consequently, PacifiCorp and Idaho Power argue that QF power costs should not be subject to prudency disallowances and should automatically be included in rates.

Although PacifiCorp acknowledges that there is no history of disallowance of QF power costs in any state in which the company provides service, PacifiCorp maintains that the potential for disallowance is a significant concern, particularly since QF power purchase costs may be more than other energy purchase costs. Indeed, PacifiCorp opines that prevalent perceptions that utilities are reluctant to contract with QFs may be due to utilities' efforts to mitigate exposure to regulatory disallowance. PacifiCorp also notes concerns that, as a multi-state utility, some portion of its costs for Oregon QF purchases may be disallowed in other jurisdictions. Idaho Power and PacifiCorp recommend that each QF power purchase contract be filed with the Commission and approved on an individual basis. Idaho Power indicates that this has been the practice of the Idaho Commission for the past twenty years. ICNU, Sherman County and Simplot all support pre-filing of QF power purchase contracts and pre-approval of associated costs, although ICNU notes that the Commission should continue to exercise oversight over the administration of QF contracts.

Staff disagrees that QF power purchase contracts should be pre-filed or pre-approved. Staff argues that the basic regulatory compact allows utilities to recover all prudently incurred costs, including payments to QFs, and that no greater assurances are needed. Staff observes that the Commission does not individually review other power purchase contracts and asserts that the utilities have failed to demonstrate why QF contracts should be treated differently. Staff notes that there is no history of past disallowances to cause concern and maintains that the Commission should retain the discretion to review utility actions in connection with a QF power purchase contract. Moreover, Staff contends that the Commission's approval of each QF contract would add unnecessary delay to the QF power purchase contracting process which developers cannot afford. PacifiCorp counters that the Commission could dispense with individual QF contract review and make a general finding in this order that QF power purchases executed pursuant to approved tariffs and a standard contract form are per se reasonable for ratemaking purposes.

2. Resolution

While we agree with parties that QF power purchase contracts are unique among other power purchase contracts, we conclude that the unique characteristics of QF contracts already provide utilities with sufficient assurances, pursuant to the traditional regulatory compact that governs cost recovery, and that costs incurred under the contracts will be recovered. For example, in this Order, we have directed utilities to file QF power purchase standard contract forms. Those forms will be pre-approved for compliance with all standards set forth in this Order or still applicable prior orders. Although pre-approval of the standard contract form is not pre-approval of a utility's recovery of costs that are incurred under a particular standard contract, utilities are assured, to the extent a standard contract is entered into with a QF, that we have pre-approved the rates, terms and conditions of the agreement with the QF. With regard to non-standard contracts, utilities have the obligation to negotiate and administer non-standard power purchase contracts with QFs that comply with federal and state mandates. The good faith fulfillment of this obligation is the best means for a utility to mitigate the risk of prudency disallowances associated with QF contracts. Indeed, we find utilities' lack of discretion regarding issues such as the location, timing, and cost effectiveness of QF power contracts favors the likelihood of a QF contract being deemed prudent. We determine that it is unnecessary and inappropriate to treat cost recovery of costs incurred under QF contracts any differently than cost recovery is handled for all other power purchase contracts.

We do so because we agree with ICNU that we should maintain our ability to oversee the administration of QF contracts. We disagree with ICNU, however, that we would be able to effectively oversee the administration of QF contracts should a contract be pre-approved with regard to general prudency and cost recovery issues, in addition to the approval of its rates, terms, and conditions, if it is a standard contract. Due to the finality of our decisions, such pre-approval would foreclose future opportunities to address administration of the contract. We also are not convinced that we have the legal authority to bind future Commissions on ratemaking treatment of long-term contracts.

D. REPEAL OF PURPA

1. Parties' Positions

PacifiCorp requests that the Commission address the issue of recovery of QF contract costs in the event that PURPA is repealed by the United States Congress. Although PacifiCorp expects to be able to continue recovering costs associated with then existing QF contracts should PURPA be repealed, PacifiCorp desires the authority to terminate QF contracts in the event that cost recovery will not be available.

Staff objects, arguing that a QF should be able to rely on the full term of a power purchase contract. Staff recommends that the Commission clarify that, absent contrary direction by federal or state law, the repeal of PURPA would not terminate then existing QF contracts. ODOE, Weyerhaeuser and ICNU agree, observing that a PURPA termination clause would have a chilling effect on QF financing.

2. Resolution

We agree that existing QF contracts should not terminate upon the repeal of PURPA, but should continue in effect with utilities able to recover contract costs under normal regulatory principles and procedures. We cannot, however, predict the provisions of future legislation, although the repeal of PURPA on a retroactive basis might be legally barred. We direct utilities to insert a clause in any QF contract that specifies that QF contracts do not terminate upon the repeal of PURPA, unless such termination is mandated by federal or state law. We believe this provision provides all the protection that is available under the law, but should not have any adverse effect on financing as it imposes no additional risk on QFs.

E. ADMINISTRATIVE RULES REVISIONS

1. Overview

The federal PURPA statute[73] and related FERC regulations[74] are applicable to, and the Commission is responsible for implementing the same, for all three electric utilities operating in the state of Oregon. Pursuant to electric industry restructuring and Senate Bill 1149, PacifiCorp and PGE have been exempted from the Oregon PURPA[75] pursuant to ORS 757.613(4). With this exemption, the Commission's PURPA regulations at Division 29 of the Oregon Administrative Rules[76] were also amended to not apply to the state's electric utilities.

2. Parties' Positions

Asserting that it was inappropriate to exempt the state's electric utilities from the Commission's PURPA regulations because they implement both Federal and Oregon PURPA law, Staff recommends that the Commission open a rulemaking to consider whether, and how, to modify Division 29 of the Oregon Administrative Rules. Staff states that the rulemaking would address the consistency of the rules with federal PURPA law, and to clarify which rules, if any, apply to electric utilities given the provisions of ORS 757.612(4).[77] Staff initially proposed that a temporary rulemaking be opened for these purposes in order to address the issues expediently and to prevent potential financial harm to QFs. In response to several parties' opposition to a temporary rulemaking, however, Staff ultimately recommends that the scope and nature of the rulemaking be determined at the start of the new proceeding.

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[73] *See supra* note 2.
[74] *See supra* note 10.
[75] ORS 758.505 through 758.555.
[76] *See supra* note 11.
[77] After the passage of Senate Bill 1149 (SB 1149), OAR 860-029-0001 was modified to provide that rules in the division did not apply to public utilities that satisfy their public purpose obligations under ORS 757.612.

PacifiCorp and PGE agree that it is appropriate to open a rulemaking that addresses the Commission regulations implementing federal PURPA law, but disagree that it is necessary to implement temporary rules. PacifiCorp states that Staff has not demonstrated how QFs may be financially harmed without temporary rules. Both PacifiCorp and PGE call for a deliberate review of Commission regulations.

3. Resolution

We concur with all parties commenting on this issue that it is appropriate to open a rulemaking to update our PURPA-related regulations. We do not find, however, that a case was made for the implementation of temporary rules. A rulemaking will be opened at a later date to revise our PURPA-related regulations on a permanent basis.

F. TARIFF CONTENT

1. Parties' Positions

The Commission's current rules require utilities to set forth standard contract rates and terms in tariffs that are filed with the Commission.[78] Staff proposes that this rule be retained, but advises that utilities be required to augment the information that is currently provided, in addition to filing standard contract forms. Staff recommends that tariffs specify approved 20-year avoided costs and set forth detailed information about avoided cost pricing. Staff also recommends that tariffs should state that standard avoided costs are the starting point for negotiation of non-standard contracts and set forth the FERC-mandated factors that may result in adjustment of these rates. To the extent the Commission adopts Staff's recommendations on several issues in this proceeding, Staff recommends that the tariffs specify policy decisions. For example, Staff suggests that tariffs include a statement that the rates paid under a standard contract are established upon execution of the contract and continue during the term of the contract, as well as a statement that QF contracts do not terminate in the event of the repeal of federal PURPA laws.

PacifiCorp agrees that tariffs should be supplemented to conform to the Commission's Order in this docket, in addition to standard contract forms being filed with the Commission. PacifiCorp does not oppose Staff's recommendation that tariffs set forth full avoided cost pricing information. PacifiCorp also recommends that tariffs contain information about the process for entering into a QF power purchase contract.

PGE disagrees, taking the position that current tariff filings are sufficient and opining that tariffs should be minimalist in nature. PGE argues that tariffs should contain only key information, including specification of avoided costs, pricing options and interconnection requirements. PGE observes that detailed information is better made

[78] *See* OAR 860-029-0040(4)(a).

available upon request or electronically at a utility's website. Staff counters that the Commission's rules favor making all relevant information available through tariffs.[79]

2. Resolution

The goal of tariffs is to provide sufficient information about the terms, rates and conditions of utility service to an inquiring third party. We have already determined that information provided in tariffs will be supplemented with filed standard contract forms that contain full information about the terms, rates and conditions governing the sale and transfer of electrical energy between a utility and a QF project with a design capacity at or under 10 MW. We conclude, therefore, that the pertinent tariffs should provide information that will not be provided in the standard contract forms. Our objective is to ensure that the combination of tariffs and standard contract forms will provide a potential QF developer with readily accessible information that facilitates a decision by the QF developer about whether to contact a utility for further information.

We expect tariffs to contain information including the following: (1) full details about the process to enter into a standard contract or a negotiated contract, including instructions to contact a utility for further information; (2) specification of avoided costs including how they are calculated; (3) details about how non-standard contracts are negotiated, including a statement that the starting point for negotiation of price is standard avoided costs and that standard avoided costs may be modified to address specific factors mandated by federal and state law; (4) delineation of these factors; and (5) general information about pricing options.

ORDER

IT IS ORDERED that:

1. Within sixty days of the effective date of this order, each electric utility shall file by application, and serve upon all parties to this proceeding, one or more standard contract forms that set forth standard rates, terms and conditions that are consistent with the policy decisions made in this order.

2. The standard contract form shall become effective 30 days after the date of filing, unless otherwise suspended by the Commission. Prior to effectiveness, the standard contract forms shall be considered initial offers.

3. A QF or electric utility which signs an initial offer may not modify such offer until the term of the resulting contract expires. Any later modifications to a standard contract form will be prospective only and will not alter the terms of the initial offer.

[79] *See, e.g.*, OAR 860-022-0010.

4. Each electric utility shall also file, with its standard contract forms, revised tariffs that implement the resolutions made in this order.

5. Tariffs shall become effective 30 days after the date of filing, unless otherwise suspended by the Commission.

6. A subsequent phase of this proceeding will be opened to address issues previously identified by the parties, as well as those identified in this order.

7. Rate recovery of hedging costs to mitigate indexed QF rates may be addressed in appropriate future dockets, such as a utility's general rate case.

8. A rulemaking will be opened at a later date to revise, on a permanent basis, the Commission's PURPA regulations at Division 29 of the Oregon Administrative Rules.

Made, entered, and effective MAY 13 2005.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

Oregon Public Utility Commission

Docket No. UM 1129, ODOE Rebuttal Testimony of Jeff Keto

Jan. 20, 2006

HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

January 20, 2006

VIA EMAIL AND U.S. MAIL

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, #215
P.O. Box 2148
Salem, OR 97308-2148
Puc.filingcenter@state.or.us

Re: *In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*
OPUC Docket No. UM 1129
DOJ File No. 330-020-GN0041-04

Enclosed for filing are an original and five copies of the rebuttal testimony of Carel DeWinkel and Jeff Keto with attachments, offered by the Oregon Department of Energy in the above-captioned matter for filing with the Public Utility Commission today.

Sincerely,

/s/ *Virginia L. Gustafson for*

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

Enclosures

c: Phil Carver, ODOE
Carel DeWinkel, ODOE
Jeff Keto, ODOE
UM 1129 Service List

JLP:jrs/GENP0108.DOC

PHASE 1 COMPLIANCE FILING REBUTTAL TESTIMONY OF JEFF KETO

Q: PLEASE, STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A: My name is Jeff Keto. I am the Loan Manager of the Small Scale Energy Loan Program (Loan Program), Oregon Department of Energy. My business address is 625 Marion St. N.E. Salem, Oregon. My educational background and professional background is described in ODOE Exhibit No. 6, submitted in this matter.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The subjects of my testimony are a cap on default damages, minimum contracted power delivery, damages in the event of a delay in commercial operations and contract termination (issues 5 and 36).

Q: WHAT IS THE BASIS FOR YOUR RECOMMENDATION OF A CAP ON DEFAULT DAMAGES?

A: In testimony ODOE recommended the contract cap on default damages be set at the value of the contracted minimum power delivery during the default period. (ODOE/Exhibit 6/Keto/Page 16, Lines 19-21). In response to Staff's data request #20 ODOE responded "I would not recommend financing if projected maximum damages under the power purchase agreement could not be paid from a reduction in future revenue within a reasonable time while keeping expenses and debt service current." Additionally, in testimony ODOE stated "To avoid potential negotiations ODOE recommends the standard contracts state a minimum amount of delivered power based on the type of resource. ODOE recommends setting annual minimum power delivery based on the following capacity factors of nameplate ratings: 5 percent for solar, 10 percent for hydro and wind, 20 percent for geothermal, biomass or natural gas fired cogeneration. The percentage should be adjusted by the percentage of power a QF intends to use on site." (ODOE/Exhibit 6/Keto/Page 7, Lines 17-23).

The recommended cap on default damages is based on the recommended minimum power delivery requirements. As an example, a biomass generation project that has a long-term projected capacity factor of 85% and establishes the contract minimum delivery at a capacity of 20% would have a cap on damages of about 23% of its anticipated generation (20/85). This 23% would be close to the maximum amount the QF could be expected to repay the utility in a reasonable amount of time and still have funds for plant operations and debt service. Our recommendation for a default damages cap was complementary with our recommendation for the minimum delivery requirements.

Q: DOES ODOE AGREE WITH STAFF'S RECOMMENDATION THAT THE CAP ON DEFAULT DAMAGES BE BASED ON 110% OF THE UTILITY'S FORWARD MARKET PRICES AT THE TIME OF CONTRACT EXECUTION? (Staff 1000/Schwartz 1, Page 53)

A: Yes. If the Commission does not accept ODOE's minimum delivery requirements by project type, ODOE concurs with Staff that the cap based on 110% of the utility's forward market prices at the time of contract execution should be used. This provides what is needed for financing: a quantifiable cap at the time of loan underwriting and a maximum amount that could be repaid in a reasonable time and still maintain project viability.

Q: DOES ODOE AGREE WITH STAFF RECOMMENDATION TO MODIFY THE CONTRACTS "TO EXCLUDE DELAY OF COMMERCIAL OPERATIONS AS AN EVENT OF DEFAULT THAT ALLOWS TERMINATION IF THE UTILITY DETERMINES AT THE TIME OF CONTRACT EXECUTION THAT IT WILL BE RESOURCE-SUFFICIENT AS OF THE QF

ON-LINE DATE SPECIFIED IN THE CONTRACT"? (EMPHASIS ADDED) (STAFF 1000/SCHWARTZ 1, PAGE 35).

A: Not entirely. While ODOE agrees with not allowing termination as recommended by Staff, ODOE is concerned that utilities will include in their contract a provision allowing termination if the utility is not resource-sufficient. The PacifiCorp contract (11.2.2) allows an opportunity to cure for a delay in commercial operations—a provision critical to obtaining financing. The PGE contract does not include such an opportunity to cure. The Idaho Power contract provides ten months cure provision in (section 5.4) if the scheduled operation date is not met. Because a reasonable opportunity to cure will increase ODOE's ability to finance projects, ODOE recommends that the Commission require PGE to include opportunity to cure language similar to PacifiCorp or language similar to Idaho Power that extends the time of default as stated above. ODOE further recommends that the Commission retain the PacifiCorp and Idaho Power contract language sited above.

Q: STAFF/1000 SCHWARTZ/1, PAGE 37 LINES 14-19 STATES "IDAHO POWER STATES THAT IT WOULD NOT TERMINATE A QF CONTRACT DUE TO REDUCED RESOURCE AVAILABILITY RESULTING FROM ADVERSE NATURAL MOTIVE FORCE CONDITIONS OR PRODUCTION CURTAILMENTS AT THE HOST INDUSTRIAL FACILITY, UNLESS THE PROJECT APPEARS TO HAVE PERMANENTLY CURTAILED ITS GENERATION TO VERY LOW LEVELS AND THE DEVELOPER IS NOT MAKING REASONABLE EFFORTS TO CURE THE PROBLEM." DOES ODOE SUPPORT THE COMMISSION REQUIRING THIS LANGUAGE IN ALL STANDARD CONTRACTS?

A: Yes. We support such standard language. In response to ODOE's data request #9, Staff stated:

> "Staff has testified throughout this proceeding that weather should not be a cause for default or termination. Staff supports the use of a Mechanical Availability Guarantee (MAG) as the basis for determining default for under-delivery. Weather-related under-deliveries would not trigger default or termination under such a mechanism.

> Without a MAG, utilities must rely on the QF to account for adverse natural motive force conditions in designating minimum annual generation, with supporting documentation. Similarly, a cogeneration QF should account for production curtailments in designating minimum generation. Avoided cost rates are based on a firm proxy resource. In order for a utility to avoid such a resource, the QF must provide reasonable estimates of anticipated generation.
>
> Under PGE's standard contract, the Company will not terminate for under-delivery unless the QF has under-delivered for two consecutive years. Therefore, Staff does not believe it is necessary for the Commission to require PGE to add language consistent with Staff's testimony, cited above.
>
> Under Idaho Power's standard contract, the Company will not terminate a QF unless it fails to deliver at least 10% of its minimum obligation in any contract year. If, for example, a hydroelectric project does not produce energy for a year due to temporary lack of water, the contract would allow for termination, even though the Company states it would not terminate the contract under such a circumstance. In the absence of a MAG, Staff would not object to a party recommending the Commission require Idaho Power's standard contract to include language consistent with Staff's testimony, cited above, for intermittent renewable resources.
>
> PacifiCorp's contract provides no exceptions for termination due to under-delivery other than events excused by force majeure, which do not include lack of wind or water. In the absence of a MAG, Staff would not object to a party recommending the Commission require PacifiCorp's standard contract to include language consistent with Staff's testimony, cited above, for intermittent renewable resources."

ODOE has testified in ODOE/Exhibit 6/Keto/Page 9 that termination for under delivery should not be allowed because a lender needs time to help correct generation project problems and possibly foreclose and sell a project. ODOE recommends that the Commission require that QF contracts include language either similar to the Idaho Power statement in Staff's testimony above (regarding non-termination for under-delivery because of lack of motive force or production curtailment at the host industrial facility if the developer is making a reasonable attempt to increase the generation) or language as in PGE's contract (that PGE will not terminate for under-delivery unless the QF has under-delivered for two consecutive years).

Q: IS ODOE CONCERNED WITH TERMINATION DAMAGES IN THE UTILITY CONTRACTS?

A: Yes. ODOE is concerned that if a power sales contract is terminated and it must take over the project as a result of a loan default, ODOE may need to pay any termination damages out of any sale proceeds of the project or before obtaining a new power sales contract for the project. These damages may make restarting a project uneconomic. To reduce this risk, ODOE has stated above that termination should not be allowed except in cases of an extended period of under-delivery or after an opportunity to cure for a delay in commercial operations. This extra time allows a lender to help cure any default or sell the project and avoid termination and payment of damages.

Q: DOES THIS CONCLUDE YOUR TESTIMONY.

A: Yes.

Oregon Public Utility Commission

Docket No. UM 1129, ODOE Testimony of Jeff Keto

Aug. 2, 2004

HARDY MYERS
Attorney General

RECEIVED

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Public Utility Commission of Oregon
Administrative Hearings Division

PETER D. SHEPHERD
Deputy Attorney General

RECEIVED

AUG 0 3 2004

P.U.C

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

August 2, 2004

VIA EMAIL AND U.S. MAIL

Traci Kirkpatrick, Administrative Law Judge
Administrative Hearings Division
Public Utility Commission of Oregon
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Re: *In the Matter the Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*
UM 1129
DOJ File No. 330-020-GN0041-04

Enclosed are an original and five copies of the testimony of Philip H. Carver, Carel DeWinkel and Jeff Keto, offered by the Oregon Department of Energy in the above-captioned matter for filing with the Public Utility Commission today.

Sincerely,

Janet L. Prewitt

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

Enclosures

c: Distribution List
Carel DeWinkel, ODOE
David Stewart-Smith, ODOE
Philip Carver, ODOE
Jeff Keto, ODOE

JLP:jrs/GENJ8353

DOCKETED

Q: PLEASE PROVIDE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A: My name is Jeff Keto. I am the Loan Manager of the Small Scale Energy Loan Program (Loan Program), Oregon Department of Energy. My business address is 625 Marion St. N.E. Salem, Oregon.

Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF YOUR EDUCATION AND EMPLOYMENT BACKGROUND.

A: I received a BS in Marketing from the University of Oregon in 1977. I worked for US Bank between 1971 and 1993 as a credit examiner, commercial loan officer and district manager. I have worked for the Oregon Department of Energy, Energy Loan Program since 1997. As Loan Manager I oversee loan marketing, underwriting and documentation.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A: The purpose of my testimony is to discuss the following issues from the perspective of a lender of QF projects: contract length and price structure (Issue 1), contract size (Issue 2), and contract conditions (Issue 3).

Q: WHAT EXPERIENCE DOES THE LOAN PROGRAM HAVE IN FINANCING QF PROJECTS?

A: Since its beginning in 1980 the Loan Program has financed 21 QF projects representing a total of 67 MW of capacity.

Q: WHAT WERE THE TERMS (CONTRACT LENGTHS) OF THE 21 PROJECTS YOUR PROGRAM FINANCED?

A: The loan program has financed 16 projects for between 20 and 25 years, three for shorter terms, and two for up to 30 years.

Q: WHAT WAS THE BASIS FOR SELECTING THESE TERMS?

A: The length of the contract for the loans are individually determined and were driven by the projected power sales revenues form the proposed projects. The projected net

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available revenue, after accounting for operating and maintenance expense and a reserve, required the stated loan terms. Specifically, the revenues must be adequate to cover the loan payments, which are determined by the loan term along with the interest rate.

Q: IN LIGHT OF YOUR EXPERIENCE, WHAT CONTRACT LENGTH WOULD YOU RECOMMEND THE COMMISSION ADOPT FOR QF CONTRACTS?

A: I recommend 20 years. While developers might prefer longer terms, 20 years should allow for adequate financing of the majority of QF projects our program has reviewed. A shorter loan forces project developers to contribute more equity, which is generally not available for local, community owned projects that have inquired about financing. For many projects, terms less than 20 years will make it difficult to cover loan payments from the power sales revenue.

Q: WOULD CHANGING FROM A 1 T0 A 10 MW SIZE LIMIT REQUIRE A SHORTER QF CONTRACT TERM (E.G. 10 YEARS) TO REDUCE ANY RISK TO RATEPAYERS?

A: No, I believe a 20-year maximum contract length is necessary for successful financing for many projects. The proposed 20 years is 10 to 20 years shorter than utility ownership of natural gas and coal fired power plants, respectively, which lock utility customers in for 30 to 40 years, respectively. In addition, information obtained from the Commission's Staff Settlement Proposal showed several examples of utilities' plans or RFPs that call for contracts up to 20 years. If utilities are allowed to expose the ratepayers to long-term commitments with fossil fuel power plants or RFP contracts, the same should be true with QF contracts.

Q: WHAT PRICING STRUCTURE WOULD ENABLE PROJECTS TO QUALIFY FOR YOUR FINANCING?

A: Our financing calls for level monthly debt service. The Loan Program issues State general obligation bonds to fund its loans. We require regular monthly loan payments in order to assure that funds are available to make timely payments on the bonds. For a project to make timely loan payments, adequate power sales revenue must be received each year. A QF facility should have the choice of levelized capacity payments if early year payments are significantly lower. This would ensure adequate revenues if there are years with low capacity payments.

Q: ARE THERE ANY OTHER CONDITIONS FO PRICING YOU ARE CONCERNED WITH?

A: The power rate could be tied to PUC forecasted natural gas price, with a ceiling and floor of plus or minus 10%. Phil Carver of ODOE has testified that the gas forecast needs to be unbiased and readily available to potential QF project developers. It is very important that all the prices be published along with the standard contract so the pricing and terms are available during project conception and development. As a lender, I need to know the power sales terms in order to discuss financing. I recommend the Commission specify the pricing methodology so there is some consistency between the utilities.

Q: ARE THERE OTHER PRICING ISSUES?

A. Yes. A QF that is not producing at its contracted capacity may require a utility to purchase additional resources at a higher price. Currently, this may trigger a price penalty for the supplier. However, because this event would constitute such a small fraction of the utility load, I think a QF of up to 10 MW should not pay a price penalty for generating below capacity. It is in the financial interest of a QF to produce as much power as possible and a price penalty is not necessary.

Q: WHAT SIZE QF PROJECTS HAS THE LOAN PROGRAM PREVIOUSLY FINANCED?

A: The projects have ranged from 30 kW to 19.6 MW.

Q: WHAT ARE THE SIZES OF THE PROJECTS OVER 1 MW FINANCED BY THE LOAN PROGRAM?

A: Eleven of the projects financed by the Loan Program were over 1 MW: six of these were between 1 and 5 MW, three were between 5 and 6 MW, one was 8.5 MW and one was 19.6 MW).

Q: HAVE POTENTIAL QF PROJECTS APPLIED FOR OR INVESTIGATED FINANCING OPPORTUNITIES BUT NO PROCEEDED TO CONSTRUCTION? IF SO, WHAT TYPES OF PROJECTS HAVE REQUESTED FINANCING?

A: At least 15 potential QF projects have applied for or discussed financing with us. Project technologies include hydro, natural gas-fired cogeneration, biomass-fired cogeneration, wind, landfill methane gas and dairy digester methane gas. They range from 300 kW to 12 MW.

Q: DOES THE LOAN PROGRAM'S EXPERIENCE SUPPORT A PROJECT SIZE THRESHOLD SIMILAR TO THE RECOMMENDATION GIVEN IN ODOE'S TESTIMONY BY CAREL DE WINKEL?

A: Yes it does based on our experience. I also recommend that the Commission adopt a 10 MW threshold for a standard purchase contract. This would cover most of the QF projects that have inquired about financing. Most projects under 10 MW cannot afford the resources or time to enter into power purchase contract negotiations with the utility.

Q: WHAT OTHER CONTRACT TERMS SHOULD BE INCLUDED IN THE UTILITY TARIFF FOR QFS?

A: The tariff filing should include the standard power purchase contract with complete terms. It is important that the contract terms and pricing be readily available for review during project design and development, and discussion of financing. Project owners need to have a clear picture of potential revenue and contract terms before they apply for financing, and I need that information to evaluate the projects. In addition to the contract term and pricing, any security requirements are of great concern to developers of QF projects and to us as a lender.

Q: WHAT SECURITY REQUIREMENTS DO YOU RECOMMEND?

A: Project owners, lenders and the utility have an interest in seeing that a project is completed. Standard financing practice is to require a performance and payment bond to mitigate the risk of non-completion. I believe such bonds are a satisfactory tool for utilities to rely on to assure a project is completed.

A second risk is that a QF might cease producing power before the power purchase agreement expires. If this occurs the utility may need to replace the power with a new resource that may be more or less expensive. Because the total capacity of QFs with a standard offer contract will most likely be very small in relation to the utility's load, default security should not be required to mitigate against replacement power price risk. I hold this same position for the situation in which a QF facility produces less than contracted capacity.

In addition, QF developer's or owner's funds will be tied up in project equity, working capital and reserves, and will not be available for large security deposits. In the experience of the Loan Program, the QF default rate is very low. Requiring default security for replacement power price risk will stop a lot of good QF projects.

Q: IS THERE ANY CASE WHERE DEFAULT SECURITY SHOULD BE ALLOWED IN THE STANDARD OFFER CONTRACT?

A: Yes. In the course of a levelized payment contract there is a certain period in which a QF facility will be paid in excess of the fixed year-to-year contract price. This rate differential generally diminishes over a few years and then may be reversed--the levelized price is less than the year-to-year rate. This risk should be easily quantifiable by comparing the two price streams over the contract term. A security deposit could be required to cover this over-payment risk. If used, the security requirement should be reduced annually according to the calculated risk.

The amount of security requirement, year-by-year, should be calculated at the inception of the contract. The total amount of this security requirement should also be limited to around 2% of the capital cost of the project. (Perhaps this escrow percentage should be technology specific.) In this way a QF has the option of choosing a non-levelized rate with no default security requirement and a levelized rate with a known and manageable security deposit requirement. A letter of credit should not be required for this security deposit because it is difficult and costly to obtain for many small QF projects.

Q: WHAT IS THE LIKELY IMPACT IF YOUR SUGGESTIONS ARE REJECTED?

A: Very few, if any, QF facilities will be built. In the past decade Oregon has seen few projects. A significantly larger number of QF projects were completed in Idaho under an avoided cost tariff similar to what is being proposed by ODOE. This is despite the fact that Idaho has none of Oregon's incentive programs, including the Business Energy Tax Credit and the Loan Program, that provide strong financial incentives for QF development in our state. ODOE, in the testimony of Phil Carver , has suggested that the OPUC adopt certain of the measures used in Idaho's avoided cost tariff. We suspect that the tariff changes we have proposed will foster the completion of many of these projects.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

Oregon Public Utility Commission

Docket No. UM 1129, ODOE Direct Testimony of Jeff Keto

Dec. 9, 2005

HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

December 9, 2005

Traci Kirkpatrick, Administrative Law Judge
Administrative Hearings Division
Public Utility Commission of Oregon
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Salem, OR 97301-2551
traci.kirkpatrick@state.or.us

Re: *In the Matter of the Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*
UM1129
DOJ File NO. 330-020-GN0041-04

Dear Judge Kirkpatrick:

Enclosed is an original and five copies of the testimony of Carel DeWinkel, Jeff Keto, and Phil Carver offered by the Oregon Department of Energy in the above-captioned matter for filing with the Public Utility Commission today.

Sincerely,

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

Enclosures

c. Distribution List
Carel DeWinkel, ODOE
Jeff Keto, ODOE
Jeff Carver, ODOE

JLP:tmc/GENO6773

PHASE I COMPLIANCE FILING

TESTIMONY OF JEFF KETO

Q: PLEASE PROVIDE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A: My name is Jeff Keto. I am the Loan Manager of the Small Scale Energy Loan Program (Loan Program), Oregon Department of Energy. My business address is 625 Marion St. N.E. Salem, Oregon.

Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF YOUR EDUCATION AND EMPLOYMENT BACKGROUND.

A: I received a BS in Marketing from the University of Oregon in 1977. I worked for US Bank between 1971 and 1993 as a credit examiner, commercial loan officer and district manager. I have worked for the Oregon Department of Energy, Energy Loan Program since 1997. As Loan Manager I oversee loan marketing, underwriting and documentation.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A: The purpose of my testimony is to discuss the following Phase I Compliance issues from the perspective of a lender to QF projects: Issues 5 a, b & c, 6, 8, 13, 14, 21, 20, 33, 35 and 36.

Q: PLEASE DESCRIBE THE BENEFITS TO THE PURCHASING UTILITY OF ODOE'S PARTICIPATION IN A QF PROJECT.

A: If ODOE through its Energy Loan Program (SELP) is financing a project, we believe the utility and ratepayers receive significant protection from our due diligence, our loan conditions and covenants and the fact that we deemed the project worthy of financing. SELP requires project owners to have an equity investment in the project. Our experience is that QFs try to maximize their generation and project revenue. If there is a reduction in generation, SELP has historically worked with QFs to help improve their generation where possible. This includes upgrading controls, transmission or operating characteristics of the project. In the event a borrower does not have the resources or capability to generate sufficient power to meet contracted minimums, they are likely to be delinquent on their loan. In one such a case SELP foreclosed on a project and sold it to an operator who was able to restore generation and operate the facility effectively. SELP believes its involvement in projects helps reduce the risk to utilities and ratepayers. The combined financial risk taken by the QF and SELP is substantial relative to the risk the utility takes with a QF contract.

Q: WHY IS SELP INTERESTED IN THE POWER PURCHASE AGREEMENTS FOR QF FACILITIES?

A: The purpose of the power purchase agreement and its assignment to SELP is to provide a source of revenue sufficient to cover projected operating and maintenance expenses, debt service and a reserve, with minimal risk of disruption of that revenue stream. This income stream acts as the primary security for the loan. The power purchase agreement needs to be reviewed in its entirety for acceptance. The circumstances that make a provision acceptable in one transaction and not in another can't be cited inclusively. In general, the larger the amount of equity capital and the lower the amount of financing needed for a project, the more SELP has the ability to accept higher risk in the power purchase agreement and still finance the project. Loans that are supported by a strong financial balance sheet that includes additional revenue streams may also allow acceptance of more risk in the power purchase agreement while still being acceptable for financing. However, most of the community scale projects SELP has reviewed, have very little financial reserves and thus require a power purchase agreement with limited risk in order to finance their project. The proposed decreasing power rates over the first five years delivers sufficient risk in the financing that the probability of default and payment of damages must be very small in order to accommodate financing.

Q: WHAT IS YOUR GENERAL UNDERSTANDING OF ORDER NO. 05-584 REGARDING CREDITWORTHINESS?

A: ODOE believes, per Order # 05-584, § L(2)(c), that a QF has the option of meeting creditworthiness by making the following representations and warranties: "that the QF has good credit, including that it is current on existing debt obligations and has not been a debtor in a bankruptcy proceeding within the preceding two years." ODOE understands the Order to mean that a QF can demonstrate creditworthiness by making this set of representations and warranties without any other action or representation required.

The Order further states "we adopt Staff's proposal that requires a QF unable to satisfy credit rating requirements to provide a reasonable amount of default security by one of the following means, selected at the QF's discretion: senior lien, step-in-rights, a cash escrow or a line (letter) of credit." ODOE interprets this to mean that a utility can accept a QF as creditworthy if it has a satisfactory credit rating (long-term debt rating by Moody's or Standard and Poor's) and thus not require the QF to provide default security. ODOE believes that this does not mean that a long-term debt rating is required in addition to making the prior set of representations and warranties in order to establish creditworthiness. Requiring a long-term credit rating, which the majority of QFs would not possess, or any other condition, other than making the above set of representations and warranties, does not comply with the Order.

Q: IN GENERAL, ISSUE 5.a. ADDRESSES THE REASONABLENESS OF SECURITY PROVISIONS. HOW DO YOU RESPOND TO ISSUE 5.a.i.?

A: The filed utility contracts include requirements for creditworthiness beyond a QF making the above set of representations and warranties. Idaho Power (IP) (§ 4.1.6) states that the specified security requirements are "at a minimum," which does not bring transparency to the contract and leaves IP to add additional requirements as they see fit or to require the posting of security. PacifiCorp (§ 3.2.7) requires QFs over 3MW to have a long-term debt rating in addition to making the stated representations and warranties or post security. As stated above, ODOE believes these or similar provisions should not be allowed and are in violation of the Order.

PGE requires a QF to additionally warrant that it will continue to be current on its obligation throughout the term of the contract (§ 3.1.4). SELP interprets this to mean that if the QF was delinquent on its loan to SELP, even if we had a structured workout to bring the borrower current, PGE could declare an event of default and require default security. These provisions could lead to default without the ability of the QF to cure the default. It is unlikely the QF would have resources to meet the default security. SELP assumes that the only viable security option a QF has under such a situation is to establish an escrow account. Most likely the QF could not qualify for a letter of credit, could not give a senior lien on the project and could not give step-in-rights if it requires posting a letter of credit or similar instrument as PacifiCorp does (§ 10.5). This provision in the PGE contract would generally prohibit SELP from financing the project.

Q: HOW DO YOU RESPOND TO ISSUE 5.a.iii.?

A: If a QF is not able to make the representations and warranties to meet creditworthiness, as stated above, the Order provides that a QF can provide one of four security options (Order # 05-584, § L(2)(c)). These are: senior lien, step-in-rights, a cash escrow or a line (letter) of credit. ODOE believes that IP and PGE should define these options to provide contract transparency, much as PacifiCorp has.

Q: HOW DO YOU RESPOND TO ISSUE 5.a.ii.?

A: PacifiCorp's contract (§ 10.5) requires a letter of credit for environmental remediation in the event of QF default if the QF selects either the senior lien or step-in rights security option. ODOE believes that many renewable generation projects have little environmental remediation potential and that asking all those who choose step-in rights or a senior lien to provide a letter of credit would unduly burden them at minimal reduction in risk to ratepayers. To pose a risk to the utility and ratepayers, a QF would need to default, there would need to be significant environmental remediation required and market energy prices would need to be above contract prices. In the rare event all these condition occur and a utility chooses not to step-in they can always litigate against a QF to seek damages. ODOE believes it is not correct to ask all QFs that choose step-in rights or offer a senior lien to pay the full amount to cover a risk that will be a rare occurance by a very small percentage of QFs.

Because of the expense and the inability of most small QFs to obtain a letter of credit, ODOE believes a letter of credit should not be required for QF projects on greenfield sites. For a generation project at an industrial or brownfield site the host company should be given the option to assume this financial responsibility in lieu of a letter of credit. If the Commission approves the utilities' use of a letter of credit in the event of step-in-rights or senior lien, the Commission should qualify that a letter of credit should only be needed in circumstances where environmental remediation is a clear documented risk and the amount of the letter of credit should not exceed the documented potential risk.

Q: IN GENERAL, ISSUE 5.b. ADDRESSES THE REASONABLENESS OF THE DEFAULT AND TERMINATION PROVISIONS. HOW DO YOU RESPOND TO ISSUE 5.b.iii.?

A: In ODOE's experience financing QF projects it is difficult for many QFs to accurately predict the minimum availability of natural motive resource and thus minimum delivered power for any specific week, month or even year over that life of a twenty year contract. In our experience actual available resources do vary below those estimated for a given period during the course of a twenty-year contract. In developing projects, the available historical resource data can vary from 10 to30 years of water flow, a year or two of wind data, or the assumed availability of biomass from forest lands. Severe weather events like forest fires, severe storms, floods and droughts are unpredictable. Loan underwriting is based on a predicted long-term average availability of a resource, but variations from one period to the next are expected. Because of the variation in resource availability and the need for flexibility, ODOE loan documents do not include lack of motive force as a default. ODOE works with its borrowers in times of low available resource, without adding loan penalties, because we believe the resource will return and the project will regain generation and revenue in future periods. Adding penalties at times of low resource availability can be a financial disaster for a project.

A QF standard contract needs to accommodate variations in delivered power according to the type of resource and the variability of that resource over time. One primary risk to a QF in meeting any contracted minimum delivered power is the lack of natural motive resource due to catastrophic weather events (forest fire, severe draught, severe storm). ODOE recommends that this risk can best be mitigated by including catastrophic weather related events in force majeure, which is not the case in any of the three filed contracts. A QF should not be in default or owe damages because of unusual or severe weather conditions.

Q: HOW DO YOU RESPOND TO ISSUE 5.b.i.?

A: The Order states "we conclude that intermittent and firm resources should be valued equally" (§ C(3)), and "It is inappropriate to request that standard contracts be subject to potential negotiations to address project-specific characteristics" (§ I(2)). However, each of the filed contracts provides space for the QF to fill in an amount of delivered energy on a monthly or annual basis, which if not delivered will result in default and penalties. ODOE is concerned that settting the delivered amounts in the contract will be subject to negotiations because a QF will want to use a very low number to avoid default and the possible payment of damages while the utility will want a higher number. To avoid potential negotiations ODOE recommends the standard contracts state a minimum amount of delivered power based on the type of resource. ODOE recommends setting annual minimum power delivery based on the following capacity factors of nameplate ratings: 5 percent for solar, 10 percent for hydro and wind, 20 percent for geothermal, biomass or natural gas fired cogeneration. The percentage should be adjusted by the percentage of power a QF intends to use on site. These pre-set minimums need to accommodate a wide variety of generating projects including the small farm-scale facilities. If the contract requires minimum delivered power that is likely to put a QF in default or require payment of damages, financing the project will be very difficult if not impossible.

Q: HOW DO YOU RESPOND TO ISSUE 5.b.xi?

A: PacifiCorp's contract provides that in the event of termination a QF may not sign a new contract to sell power until after the contract expiration date (§ 11.3.2). ODOE believes this is not in the spirit of the Order and may not be allowed under PURPA. Such a restriction could preclude ODOE from foreclosing and selling the project and thus would render the project not be acceptable for financing. ODOE requires the right and opportunity to foreclose on a facility and sell it to a new owner with the original power purchase agreement remaining in effect. ODOE recommends that the Commission not allow standard contracts to prohibit a QF from making future sales to the utility if a contract default or termination occurs.

Q: HOW DO YOU RESPOND TO ISSUE 5.b.xiii.?

A: ODOE believes it is reasonable for the utilities to request the QF provide anticipated power delivery figures for planning purposes. The Net Energy Amount in Idaho Power's contract (§ 1.12 and 6.2), which is the amount of power a QF intends to deliver to IP, is also the amount that could result in penalties if not delivered. ODOE believes that the IP contract should include the monthly anticipated power delivery for informational purposes but should not use these amounts to calculate any potential penalties. Penalties should be based on a separate minimum delivered annual capacity figure the QF fills in or the capacity factors as discussed above.

Q: HOW DO YOU RESPOND TO ISSUE 5.b. AS THE ISSUE RELATES TO DAMAGES AND TERMINATION OF THE QF CONTRACT IN GENERAL?

A: ODOE recognizes that the Commission provided that a QF may owe damages if the facility does not meet the contracted commercial operations date or deliver the minimum amount of contracted power (§ L(2)(c), L(3)(c)). Any damages to cover utility costs are to be repaid by reducing future payments to the QF.

ODOE believes the Commission intended these damages to adequately protect the utility and ratepayers but also allow for the continued operation of the QF generating facility. The filed contracts allow for termination for not meeting the scheduled commercial operations date or not delivering the minimum required power in any given period. This should not be allowed. A lender needs the time to work with a borrower to cure defaults and correct any project construction or operational problems. A lender also needs the time to foreclose on a project, make improvements or repairs, and resell it with a valid power purchase agreement.

Termination for late start up or under-delivery of power will make many QF projects unfinancable by SELP. If termination is allowed for under-delivery of power, it should be allowed only in the most egregious cases that do not involve that lack of motive force, and the contracts should allow the QF to make repairs and correct operational problems or allow the lender to take legal action and facilitate renewed generation within a commercially reasonable time frame. The time needed to accomplish these actions could be more than one year if parts, contractors or transportation are difficult to obtain. If the Commission allows termination for under-delivery in egregious cases, SELP recommends that the contracts allow two years to cure the lack of power delivery before termination is an option.

Q: HOW DO YOU RESPOND TO ISSUE 5.c. AS THE ISSUE RELATES TO THE CALCULATION AND LEVEL OF DAMAGES IN GENERAL?

A: As stated above, the Order provides for payment of damages by the reduction of future contract payments. PacifiCorp's contract states that it will work with the QF to limit the reduction in payments to provide for continued facility operation and payment of debt (§ 11.4.2). ODOE recommends that similar language be inserted in IP and PGE standard contracts. If contract penalties can reduce revenue below that which is needed for continued facility operation and payment of debt service, such penalties will reduce the amount of debt any project can obtain and require additional equity that simply is not available for many locally-owned QF projects. In the Order the Commission indicates that "future payments after the default period ends shall be commensurately reduced for a reasonable period of time" (§ L(2)(c).

Q: HOW DO YOU RESPOND TO ISSUE 6, WHICH PROVIDES: Should tariffs for Qualifying Facilities include a detailed list of procedures, including timelines, to comply with the Commission's directive that such tariffs contain "full details about the process to enter into a standard contract or a negotiated contract," per Order No. 05-584 at 59? If yes, which procedures and timelines should be included at a minimum, and what timelines are appropriate?

A: ODOE recommends that the tariffs provide that the utility will review standard contracts submitted by a QF and sign or provide the reason for not signing within 30 days of the date submitted.

Q: HOW DO YOU RESPOND TO ISSUE 8, WHICH PROVIDES:

Should increased Qualifying Facility output resulting from changes in operation of generating equipment — for example, improving its efficiency or operating at a higher power factor — qualify for the full avoided cost prices in the tariff as of the effective date of the agreement? Should increased generation resulting from efficiency improvements that increase the project's output above the nameplate rating specified in the contract be entitled to full avoided cost prices, so long as the project's nameplate rating remains at or below 10 MW? If so, should the increased generation be priced at the full avoided cost in the tariff as of the effective date of the agreement or as of the date of the improvement? Can Seller change the generator nameplate rating if equipment replacement is necessary?

A: The standard contract should not penalize or prohibit QF projects from making efficiency improvement to their generating facility. The standard tariff should also recognize that a QF may want to increase the net generation of a project. At the same time, ODOE recognizes that the standard contract is limited to 10MW nameplate capacity and that adding any additional generation will require a review of interconnect and transmission availability. In addition, the economics of power rates and the cost of generation will likely vary over time.

To accommodate improvements in efficiency and the possible increase in generation at a QF site, ODOE suggests that the original contract payment terms should apply to the facility generation up to original nameplate rating. If efficiency improvements or additional generation capacity is installed, a QF should be paid at the original contract rates up to the original nameplate rating, Any increase of nameplate rating up to 10MW should be paid at the avoided cost rates in effect as of the date of the improvement. This provides the QF with capacity payments for any additional generation but only up to the facility's nameplate rating.

Q: HOW DO YOU RESPOND TO ISSUE 13, WHICH PROVIDES:

Can Seller choose to service some or all of its own load that is not plant parasitic load to determine Net Output?

A: A QF should be able to service part or all of its own load and enter into a standard contract for the net generation provided the nameplate capacity is no greater than 10MW. Allowing a QF to supply their own load as part of Net Output provides a good incentive to some QFs to embark on the complex and costly task of developing a generation resource.

Q: HOW DO YOU RESPOND TO ISSUE 14, WHICH PROVIDES:

If a utility and a Qualifying Facility Seller under 10 MW mutually agree to change a few terms of the standard contract for a facility but still use the applicable standard tariff, is this arrangement considered a PURPA contract in future rate making proceedings?

A: ODOE supports the ability of a QF and utility to make mutually agreeable changes to a standard contract form, while still using the published tariff, as this helps facilitate the development of additional generation resources. Mutually agreeable changes will protect ratepayers because of utility review and benefit ratepayers from a new energy resource. As the utility would still be obligated to purchase this power under PURPA, the modified contract should enjoy whatever protections a PURPA contracts offers.

Q: HOW DO YOU RESPOND TO ISSUE 21, WHICH PROVIDES:

If the Commission's decision in AR 495 allows, should standard contracts contain a waiver of claim to ownership of environmental attributes of delivered power as provided in § 8.1 of Idaho Power's contract?

A: The standard contracts should specify the ownership of environmental attributes of the QF power (a.k.a. renewable energy certificates or RECs). This should conform to the Commission's decision in AR 495. If the Commission decides the RECs belong to the utility, the avoided cost payments should reflect the market value of the RECs.

Q: HOW DO YOU RESPOND TO ISSUE 30, WHICH PROVIDES:

Are prohibitions against any liens or encumbrances on the project other than for third party financing in § 3.1.5 of PGE's contract too restrictive?

A: This provision may preclude or reduce the availability of financing. As a lender, we would ask that an exception be included in the contract to allow for statutory liens. Contractors, material suppliers and others have the authority under law to file liens, which may occur during construction, maintenance or upgrade of a generating facility. The filing of this type of lien can't be prohibited. We would not want the filing to automatically trigger a default in the contract and subsequent penalties or termination. An exception for statutory liens should also recognize that the project owner has the right to contest a lien in good faith, which may involve significant time to clear the lien.

For the Commission's reference, here is the current language in ODOE loan agreements:

> "Permitted Liens" means, with respect to the Collateral, in addition to any liens and security interests created by the Security Documents:
>
> (a) Any liens for taxes, assessments, levies, fees,

water and sewer rents, and other governmental and similar charges and any liens of mechanics, materialmen, laborers, suppliers or vendors for work or services performed or materials furnished in connection with the Premises or the Project, which are not due and payable or which are not delinquent or the amount or validity of which are being contested in good faith and execution thereon is stayed or, with respect to liens of mechanics, materialmen, laborers, suppliers or vendors, have been due for less than 60 days;

(b) Easements, rights-of-way, servitudes, restrictions, oil, gas or other mineral reservations and other minor defects, encumbrances and other matters affecting title to the Premises, including without limitation, rights reserved to or vested in any municipality or public authority to control or regulate the Premises or to use such Premises in any manner, to the extent set forth in Preliminary Title Report, dated _________, _______ issued by Title Company.

Q: HOW DO YOU RESPOND TO ISSUE 33, WHICH PROVIDES:
Is it reasonable for Idaho Power to require in § 3.3 that a hydroelectric Qualifying Facility warrant that it has a FERC license at the time of execution of the agreement, rather than warrant it will have a FERC license prior to the first operation date?

A: SELP supports requiring a FERC license at the date of initial operations. Based on a limited review of older hydro projects SELP financed, SELP normally required a FERC license at the time of loan closing and first loan disbursement. SELP staff believes that loan advances were made on at least one hydro project prior to the facility receiving its FERC license. In order to advance funds SELP would require a signed PPA. Allowing a QF to wait until first operations for a FERC license adds flexibility in project development. The standard contracts should require hydro QFs to have applied for a FERC license but should not require the QF to have a license at the time the standard contract is signed. Requiring a license to obtain a standard contract may reduce the viability of some hydro QF projects with negligible risk reduction for utilities and ratepayers.

Q: HOW DO YOU RESPOND TO ISSUE 35, WHICH PROVIDES: 'In the event of the inability of a QF to establish creditworthiness, determination of an appropriate amount of default security to be required (relating to standard contract only).

A: In earlier testimony ODOE stated that default security may be specific to project type, but should be limited to around 2% of project capital costs. Of the forms of default security a QF can choose from (senior lien, step-in-rights, a cash escrow or a line (letter) of credit), a senior lien would not be available if the project is financed. A letter of credit would likely not be available for most locally-owned projects, because they would not have security to pledge to a bank that provides the letter of credit. A cash escrow deposit may be the only available security option, and the amount of the escrow deposit will probably be paid from additional equity from the project owners. Financing will already be maximized based on the projected project cash flow. This means the QF must find equity to cover any additional project costs. Equity is in short supply for most locally-owned projects. We arrived at the limit of 2% of project capital costs using the following example that represents a locally owned project that SELP would like to finance. To look at the cost of an escrow deposit in terms of a potential project, ODOE has reviewed a 1.5 MW QF project that costs around $2.4 million to construct. An ODOE loan, an Oregon Business Energy Tax Credit pass-through and tax-equity contribution based on federal tax credits is projected to provide the majority of the project funding while $100,000 to $200,000 is provided by the local land owners. This project is based on some added revenue from the Energy Trust. A 2% increase in project cost for an escrow default security account would be around $50,000. This would be a significant amount for the property owners to raise. A larger sum would likely make the project unworkable. Higher equipment prices are increasing the cost of generating projects. As a result the Energy Trust is being asked to contribute more. I suspect the Energy Trust would not increase their contribution to a project just to cover a default security deposit. In this example, $50,000 represents roughly three months of projected average project power sales revenue.

Q: HOW DO YOU RESPOND TO ISSUE 36, WHICH PROVIDES:

Cap on amount of default losses that can be recouped, pursuant to future QF contract payment reductions.

A: ODOE believes a reasonable cap on the amount of losses that can be recouped by the utility for an individual event of default is the contract value of the contracted minimum power delivery during the default period.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

Oregon Public Utility Commission

Docket No. UM 1129, ODOE Surrebuttal Testimony of Jeff Keto

Oct. 14, 2004

um 1129

HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

October 14, 2004

RECEIVED

OCT 14 2004

Public Utility Commission of Oregon
Administrative Hearings Division

VIA E-MAIL AND U.S. MAIL

Traci Kirkpatrick, Administrative Law Judge
Administrative Hearings Division
Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551
traci.kirkpatrick@state.or.us

Re: *In the Matter the Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*
UM 1129
DOJ File No. 330-020-GN0041-04

Enclosed are an original and five copies of the surrebuttal testimony of Philip H. Carver and Jeff Keto, offered by the Oregon Department of Energy in the above-captioned matter for filing with the Public Utility Commission today.

Sincerely,

Janet L. Prewitt

Janet L. Prewitt
Assistaut Attorney General
Natural Resources Section

Enclosures

c: UM 1129 Distribution List
Larry Gray, ODOE
Carel DeWinkel, ODOE
Philip Carver, ODOE
Jeff Keto, ODOE

DOCKETED

JLP:jrs/GENK5603

Case UM-1129
ODOE Exhibit No.4
Witness Jeff Keto

RECEIVED

OCT 14 2004

Public Utility Commission of Oregon
Administrative Hearings Unit Division

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Oregon Department of Energy

Surrebuttal Testimony of Jeff Keto

Policy

October 2004

DOCKETED

Q: PLEASE PROVIDE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A: My name is Jeff Keto. I am the Loan Manager of the Small Scale Energy Loan Program (Loan Program), Oregon Department of Energy. My business address is 625 Marion St. N.E. Salem, Oregon.

Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF YOUR EDUCATION AND EMPLOYMENT BACKGROUND.

A: I received a BS in Marketing from the University of Oregon in 1977. I worked for US Bank between 1971 and 1993 as a credit examiner, commercial loan officer and district manager. I have worked for the Oregon Department of Energy, Energy Loan Program since 1997. As Loan Manager I oversee loan marketing, underwriting and documentation.

Q: HAVE YOU PREVIOUSLY TESTIFIED IN THIS MATTER?

A: Yes. I sponsored testimony on August 2, 2004, identified as ODOE Exhibit No. 3.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A: The purpose of my testimony is to respond to rebuttal testimony by Mark Widmer of PacifiCorp and Doug Kuns and Ted Drennan of Portland General Electric on contract length and price structure (Issue 1), contract size (Issue 2), and contract conditions (Issue 3).

Q: SEVERAL UTILITY WITNESSES ADVOCATE FOR A 15 YEAR MAXIMUM TERM FOR A STANDARD OFFER QF CONTRACT. DO YOU AGREE WITH THEIR RECOMMENDATION?

A: No. I believe the maximum term should be set at 20 Years

Q: WHAT IS YOUR BASIS FOR 20 YEAR CONTRACTS?

A: Witness Widmer stated that the current 5-year contract term was put into place by the Commission in 1996 to correspond with the competitive market place that offered similar terms in wholesale contracts. Given the current wholesale market that includes long-term contracts in the 20 to 30 year range, it would create a significant disadvantage to QFs if QF are not allowed contracts of at least 20 years. In addition, our experience in financing renewable electricity generating projects, as stated in prior testimony, indicates that many projects require 20 year financing to be economically feasible.

Q: DO YOU AGREE WITH WITNESS WIDMER (WIDMER/8 LINE 8-15, AND WIDMER/24 LINES 11-17) THAT LEVELIZED PRICING SHOULD NOT BE ALLOWED AND THAT CONTRACT PRICES FOR A GIVEN YEAR SHOULD TRACK THE UTILITY'S AVOIDED COST PRICE STREAM FOR THAT YEAR?

A: I do agree that the Commission should consider this in the case where declaration of resource surplus is abolished. Witness Widmer (Widmer/24, lines 11-17) accepts levelized capacity payments. My concern is that levelized pricing may add a default security requirement to QF projects that abolishing the surplus period would not. Even if there is a surplus period, it is not necessarily true that short-term market prices will be lower than the costs of a proxy CCCT. Whether levelization is needed will depend on the actual stream of avoided costs that will depend on the year-by-year forecasts of natural gas prices as well.

Q: WHAT MAXIMUM CAPACITY SHOULD BE INCLUDED IN A STANDARD CONTRACT?

A: As stated in my previous testimony I believe 10 MW is a reasonable size limit for standard contract.

Q: DOES THE POSSIBILITY OF SUBSIDIES TO A QF REQUIRE THAT THE COMMISSION LIMIT THE STANDARD CONTRACT SIZE TO LESS THAN 10MW?

A: No. I acknowledge that there may be some subsidy, but part of the purpose in supporting QFs is to diversify Oregon's energy resource base and provide more opportunities for distributed generation. With uncertainties in gas prices for the proxy plant and future transmission constraints and cost, we could realize additional financial value from distributed renewable generation that would offset any initial subsidy. If the structure of QF standard contracts does not support QF development, then Oregon would lose this valuable diversity of energy resources.

Q: IN DETERMINING AN APPROPRIATE LEVEL FOR A STANDARD OFFER CONTRACT, SHOULD THE AVOIDANCE OF EXCESSIVE TRANSACTION COSTS BE THE ONLY DETERMINING FACTOR?

A: No. Other revisions in contract terms supported by Staff and witness testimony are significant issues to many potential QF project owners. As I previously testified, a community-owned QF may find it impossible to complete a project if a significant level of default security is required. Having workable standard contract terms is very important. Witness Widmer stated that in his opinion, potentially higher rates in a standard offer were the motivation for QF parties to seek a higher standard offer ceiling. In my opinion, other elements of the standard contract are as important or maybe more important for projects in the one to 10 MW range.

Q: DO YOU AGREE WITH THE PROPOSAL BY KUNS AND DRENNAN FOR ESTABLISHING A 5MW LIMIT FOR WIND PROJECTS AND A 2MW LIMIT FOR ALL OTHER TYPES OF PROJECTS FOR A STANDARD OFFER CONTRACT?

A: No. The basis for the split appears to be that the output of a 5MW wind project will be close to that of other 2MW resources (Drennan, Kuns/13, lines 17-22). However, other renewable resources also have seasonal or daily variations in generation. In addition, some of the proposed biomass projects I referred to in prior testimony may operate at less than full time in order to match their plant steam load and achieve high efficiency. I believe that one limit should be set for all projects.

Q: COULD YOU COMMENT ON THE PRICING OPTIONS PRESENTED BY WITNESSES KUNS AND DRENNAN.

A: I believe the three pricing options offer a good choice for QF projects. A fixed price option needs to be based on an appropriate forecast of avoided costs. A price with a variable energy component, using appropriate monthly index of natural gas prices, can benefit natural gas-fired cogeneration facilities. A variable market-based price may appeal to some project owners.

Q: WHAT ABOUT CREDIT REQUIREMENTS?

A: Witness Carver has stated that it is important to have the best available forecast of the future price of natural gas. As natural gas fuel costs are the vast majority of the costs of the proxy CCCT, a portfolio of QF generation can hedge uncertainties in gas price forecasts and future gas availability. This is a benefit to ratepayers.

If the purpose of default security is to protect ratepayers and stockholders against the risk of higher price replacement power, then it benefits ratepayers to have renewable power generation in the portfolio and QF projects included in the resource diversity. I believe default security provisions could significantly reduce the number of new QF facilities, which in turn would increase gas price risk to ratepayers. In my opinion, the diversity and hedging benefits of QF facilities offset the potential risk of not requiring default security in the standard contract.

Q: DO YOU AGREE WITH WITNESS WIDMER'S STATEMENT THAT UTILITIES SHOULD HAVE THE RIGHT TO TERMINATE THE CONTRACT IN THE EVENT PURPA IS REPEALED OR RETAIL DEREGULATION RESULTS IN UNRECOVERABLE STRANDED COSTS. (WIDMER/19, LINES 18-20).

A: No. The possibility that the QF contract could be terminated because of future PUC or legislative decisions is of great concern to lenders. It could add a significant roadblock to project financing. Termination provisions such as Widmer proposes are generally unacceptable to our loan program unless the project has excessive equity or reserves. We rarely see a QF scale project with equity or reserves sufficient to allow for these termination risks, which could result in the need to negotiate a new contract. Worse, the utility wants to require default security--an additional drain on available project funds. I do not think termination should be allowed in either event but I acknowledge the utilities' concern for cost recovery.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

Certificate of Service

I hereby certify that on the 14th day of October 14, 2004, I served the foregoing Surrebuttal Testimony of Philip Carver and Jeff Keto, upon the persons named on the attached UM 1129 service list by electronic mail and by mailing a full, true and correct copy thereof addressed to the persons at the addresses on the UM 1129 service list.

Dated: October 14, 2004

Janet L. Prewitt

Janet L. Prewitt, #85307
Assistant Attorney General

Oregon Public Utility Commission

Docket No. UM 1734, Response Testimony of John Lowe

Oct. 15, 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1734

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Application to Reduce the Qualifying Facility	)
Contract Term and Lower the Qualifying	)
Facility Standard Contract Eligibility Cap	)
	)
	)

RESPONSE TESTIMONY OF

JOHN R. LOWE

ON BEHALF OF THE

RENEWABLE ENERGY COALITION

October 15, 2015

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John R. Lowe. I am the director of the Renewable Energy Coalition (the "Coalition"). My business address is 12050 SW Tremont Street, Portland, Oregon 97225.

Q. Please describe your background and experience.

A. In 1975, I graduated from Oregon State with a B.S. I was employed by PacifiCorp for over thirty years, most of which was spent implementing the Public Utility Regulatory Policies Act ("PURPA") regulations throughout the utility's multi-state service territory. My responsibilities included all contractual matters and supervision of others related to both power purchases and interconnections. Since 2009, I have been directing and managing the activities of the Coalition as well as providing consulting services to individual members related to both power purchases and interconnections. Further details are included on Exhibit Coalition/101.

Q. On behalf of who are you appearing in this proceeding?

A. I am testifying on behalf of the Coalition.

Q. Please describe the Coalition and its members.

A. The Coalition was established in 2009, and is comprised of over thirty members who own and operate over fifty non-intermittent small renewable energy generation qualifying facilities ("QFs") in Oregon, Idaho, Montana, Washington, Utah, and Wyoming. Several types of entities are members of the Coalition, including irrigation districts, water districts, corporations, and individuals. Except two, all are small hydroelectric projects.

Q. What are the Coalition's interests in this proceeding?

A. The Coalition has a number of key interests in this proceeding. First, our goal is to ensure fair and reasonable contract terms and conditions for projects of all size and type, and reasonable access avoided cost rates for small baseload projects historically eligible for Schedule 37 prices. Second, the Coalition's members are primarily existing QFs, and our goal is to ensure that any final order in this proceeding recognizes and accounts for the unique circumstances and benefits of existing projects and does not diminish the opportunity for these projects to continue operating. Finally, the Coalition recognizes that PURPA must work to benefit all interested parties, including the utilities, ratepayers, and new and existing QFs of various sizes. The Coalition's goal is that PURPA policies account for all these interests, and the changes (if any) adopted by Oregon Public Utility (the "Commission") are narrowly tailored to resolve specific problems. Any policy changes should not unduly harm any project type or size, and certainly should not have detrimental impacts to those projects not contributing to the alleged problems that led to PacifiCorp's filing. The Commission should understand the practical impacts of PacifiCorp's proposal, which would include permanently eliminating payment for capacity to any QFs, continuous repetition of contract negotiation, and the uncertainty in price and sale of power leading to severe limitations in project improvements. For hydroelectric projects this will likely translate to the inability to make improvements to increase efficiency and water conservation.

Q. Please summarize PacifiCorp's requests in this case.

A. PacifiCorp has requested a reduction in the maximum term of its power purchase agreements ("PPAs") with all QFs from 20 to three years, and to lower the size threshold for wind and solar QFs to 100 kilowatts ("kW").

Q. Please summarize your testimony.

A. The alleged problems facing PacifiCorp are exaggerated. The problems (if any) are not caused by small baseload Schedule 37 eligible QFs, especially existing ones. The Coalition opposes PacifiCorp's proposal in its entirety, and does not believes that the company has demonstrated that contract terms or size thresholds should be lowered for any QFs. If the Commission adopts any changes in PURPA policies, then any changes should exempt small baseload projects, and adopt more limited relief than requested by the company.

I also explain the unique reasons why that there should be no change in policy for existing projects. Existing projects also are not causing any problems, and in fact are providing significant benefits. Imposing a policy change like a shortened contract term on existing QFs could significant and unnecessary harm the utilities, ratepayers, and these projects. In addition, three-year contract terms could place existing projects' continued operation in jeopardy.

Q. Is the Coalition sponsoring any other testimony?

A. Yes. Jeremiah Camarata, the District Manager at Farmers Irrigation District, and Edson Pugh, the General Manager at Deschutes Valley Water District, are submitting testimony on the impact of reduced size thresholds and contract terms on existing baseload hydro projects. As they explain, such reductions could significantly harm and even shut down their facilities.

Q. Please summarize your specific responses to PacifiCorp's filing?

A. First, the Commission should not lower the contract terms for any QFs. However, if the Commission lowers contract terms, then it should not apply to any baseload QFs. For example, the Commission could adopt relief similar to what was done recently by the Idaho Public Utilities Commission ("Idaho Commission") in Docket GNR-E-15-01. The Idaho Commission rejected PacifiCorp's identical proposal to reduce contract terms to three years for all QFs, and adopted a more limited and nuanced change in its PURPA policies. Unlike the Idaho Commission, however, the Oregon Commission should not lower the contract term for any baseload QF, including those over the standard contract size threshold.

Second, the Commission should include a capacity payment in the contracts for QFs that renew their contracts, especially if the Commission lowers the contract term to any period which may be shorter than a utility's then-current projected resource sufficiency period.

Third, the Commission should not lower the size threshold for standard contracts for any QFs. However, if the Commission intends to lower the size threshold for standard contracts, then it should not apply to small baseload QFs. This is consistent with PacifiCorp's proposal in the case. In addition, Commission should consider a size threshold higher than 100 kW, since a reduction from 10 megawatts ("MW") would be the maximum possible and no justification has been provided for such a severe shift. Finally, the Commission should consider other forms of relief. For example, the Commission could establish an annual cap on the amount of new wind and solar projects, or adopt more stringent security deposits on larger wind and solar projects.

Q. Are there other Oregon policy goals impacted by PacifiCorp's filing?

A. Yes. There are a number of regulatory requirements and proposals that support maintaining existing and encouraging new QF development, including responding to the Environmental Protection Agency's ("EPA") new carbon reduction regulations and existing coal plant regulations, Oregon's goals to reduce greenhouse gas emissions, and Oregon's goal 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. It will be extremely difficult, if not impossible, to meet the eight percent goal without PURPA policies that allow existing QFs to continue to operate and new projects to be developed.

II. PACIFICORP ALLEGED PROBLEMS

Q. Please describe the alleged problems facing PacifiCorp.

A. PacifiCorp has supported its request to reduce the contract term with claims regarding the harm caused by new large wind and solar QFs. For example, PacifiCorp states that they have a large amount of new wind and solar projects under contract, and a large number of additional wind and solar QFs seeking new contracts. Application at 5. PacifiCorp alleges significant customer rate and reliability concerns associated with this large amount of new large wind and solar QFs. Application at 6-10.

Q. Do you agree with PacifiCorp that they are facing significant problems associated with new PURPA projects?

A. I agree that PacifiCorp is facing a large number of new contract requests and recently executed contracts. This is a legitimate issue that warrants consideration. Managing this problem is a challenge, but does not warrant foreclosing opportunities for small baseload projects that for years have been the heart-and soul of local PURPA project development. The majority of the contracted and/or proposed solar projects are located in Utah, so it is unclear why the Company is proposing a policy change in Oregon that will not impact its alleged problem, unless the real agenda remains undisclosed.

In my experience, not all of the QFs that request contracts, or that even those that enter into contracts, ever come on line. I worked at PacifiCorp after PURPA was passed and in the early years of the 1980s and there was a huge number of new requests for hydroelectric projects. Only a small fraction ever entered into contracts and an even lesser number were constructed. There are the traditional forces related to project financing, ordinary risks of development, resource or project location and interconnection costs, utility processes and interests, and many other factors that ultimately reduce the number of proposed projects that are eventually constructed.

Utilities like PacifiCorp traditionally and for many reasons over-estimate the costs and harms associated with QFs, and always underestimate their benefits. In any event, it is unlikely that small baseload QFs have created any significant problems that warrant correction by the Commission.

III. SIZE THRESHOLDS SHOULD NOT BE REDUCED

Q. Should the Commission address PacifiCorp's alleged problems by lowering the standard contract size threshold?

A. No. The Commission should reject PacifiCorp's proposal to lower the standard contract size threshold. Alternatively, if the Commission is inclined to adopt any relief, then it should: 1) only lower the size threshold for wind and solar, as proposed by PacifiCorp; 2) lower the size threshold to something significantly higher than 100 kilowatts; and/or 3) adopt a different remedy, including a potential annual cap on new wind and solar projects or higher security deposits for new larger projects.

Q. Please describe the standard contract rate threshold.

A. The standard contract rate eligibility threshold is the maximum size for a QF to be eligible to sell power at a utility's published avoided cost rates and to apply the standard form agreement, both approved by the Commission.

Q. Is the standard contract and rate threshold important?

A. Yes. It is far more difficult in time, money and expertise for QFs to negotiate and complete contracts over the rate eligibility threshold than those below the threshold. All states that I work in allow smaller QFs to obtain published rates instead of negotiating rates or having their rates determined by a utility-controlled computer model runs. This also typically includes the application of a standard form contract minimizing the need to negotiate contract terms.

There are a number of important reasons for treating smaller projects differently, some which include developer sophistication, transaction costs, economies of scale, and the inability to economically access alternative markets.

It is important to recognize the unique difficulties facing smaller projects, and allowing smaller projects to sell power at a published rate helps mitigate some of these difficulties.

Negotiating contracts can be costly in terms of upfront transactional costs. Small QFs do not typically have in house attorneys and experts with the skills to assist in the evaluation and negotiation of contracts. Therefore, they often need to hire outside experts. In addition, negotiating a QF contract with a utility can take a great deal of time. This makes completion of such agreement quite challenging and risky since many factors important to the negotiation can change during an extended process. All of these transactional costs can impose significant economic burdens and risks, and can make a smaller project uneconomic.

Small projects also do not have the options available to larger projects. For example, large scale resources developed by utilities or large independent power producers benefit from being sized so that the dollar-per-kilowatt investment required to build the plant is less than for a much smaller sized QF of the same basic technology. Similarly, it is my understanding that the typical short-term power sale trades in the Pacific Northwest electricity market are generally for blocks of 25 MW power, and small QFs cannot effectively participate in this market.

Q. If the Commission lowers the size threshold, is it appropriate to limit such a reduction to wind and solar QFs?

A. Generally I agree that it is not necessary or appropriate to treat all project types and sizes in a similar fashion. Adjustments to policy on PURPA's implementation are appropriate from time to time, and limiting the size threshold for wind and solar, without the drastic change proposed, may be an appropriate adjustment under current conditions. While I am not agreeing with PacifiCorp's allegations of harm, none of its alleged problems are being caused by existing and small QFs.

In addition, existing and operating QFs provide PacifiCorp with significant benefits. For example, PacifiCorp relies upon their continued operation to provide needed capacity benefits. Limiting the size threshold to these operating projects applicable after contract expiration does not address the problems identified by the utilities, and may harm the utility, its ratepayers, and the projects. The Commission's final order in this proceeding should be careful not to harm those QFs that are not contributing to the alleged problems faced by the utilities.

Q. Has PacifiCorp justified lowering the size threshold for wind and solar to 100 kWs?

A. No. PacifiCorp has not explained why the size threshold should be 100 kWs, instead of 1 MW, 3 MWs, 5 MWs, or something else. For example, PacifiCorp has not demonstrated that a 200 kilowatt facility is similar to a 10 MW facility, and that very small facilities should not have the protection of standard contracts and rates. In the end, the Commission should adopt the minimum amount of relief to address the alleged problems by PacifiCorp in order to minimize the harm to QFs.

Q. Are you concerned about the impact of the Commission's generic PURPA investigation in UM 1610 on this proceeding?

A. Yes. For example, PacifiCorp and Staff recommend that the company be allowed to use its complex power cost model to set avoided cost rates for QFs above the size threshold because larger QFs are sophisticated and have sufficient resources to analyze the model. While the Coalition strongly opposes the use of PacifiCorp's computer model for setting avoided cost rates, it is difficult to imagine that a 200 kilowatt QF, let alone a project of several MWs, will have the sophistication and resources to analyze the avoided cost rates that are set using PacifiCorp's computer model.

IV. CONTRACT TERMS SHOULD NOT BE REDUCED

Q. Should the Commission address PacifiCorp's alleged problems by lowering the standard contract term?

A. No. The Commission should reject PacifiCorp's proposal to lower the standard contract term. Alternatively, if the Commission is inclined to adopt any relief, then it should not apply to small or existing baseload QFs. In GNR-E-15-01, which included similar proposals to lower the contract term, the Idaho Commission rejected PacifiCorp's proposal to reduce the contract term for all QFs, and only reduced the contract term for QFs under the rate eligibility cap, as proposed by Idaho Power Company ("Idaho Power").

Q. You previously mentioned existing QFs. Please explain what you mean by existing QFs.

A. Existing QFs are those projects that are already operating and are generally selling power to the interconnected utility. Some of these projects have been operating since the mid 1980s.

Existing projects face some unique challenges. Existing projects must enter into a replacement contract when their current contract expires. First, this means there is no flexibility to the time at which such a new contract would start. This means that a new contract always starts during a contract term that includes an initial period of utility resource sufficiency, and the new contract term may be shorter than the then-current resource sufficiency period. In other words, if a project is not allowed to replace its contract in advance of expiration, and the resource sufficiency is at least three years long, then the new contract will not include a period of resource deficiency based prices. Historically, resource sufficiency is four or more years long, and today's resource sufficiency periods are more than twice that number of years. This is further explained below.

Most existing projects have been operating for years, and may require major replacement and/or upgrading of their equipment, conveyance structures, and other facilities including interconnections. New interconnection agreements are often required. There can be significant time and costs involved in addressing these needs or requirements

Q. What are existing projects financing and planning horizon needs related to a new or replacement power purchase agreement?

A. Existing projects have financing and planning needs very similar to those of proposed projects. Since nearly all of the Coalition's 50-plus projects involve existing projects, this is matter of significance concern and experience. Many members' have already gone through a contract renewal. Often the expiration of a power purchase agreement is the appropriate time to revise and update a project.

This could include additions and improvements as well as updating of equipment to then-current standards. These changes are often significant in terms of financial, process and timing considerations that must align with the contracting process and contract terms, including contract length and prices of a power purchase contract renewal. Short-term contract renewals will impact the opportunity to make necessary and mutually desirable project improvements. In the case of hydroelectric projects, this would mean that short contract terms would result in the loss of efficiency and water conservation improvement opportunities.

Q. Are existing QFs treated differently than new QFs?

A. Yes. For example, existing QFs are included in the utilities' resource plans. Most baseload projects especially hydro are very long-term projects and have little locational flexibility. These QFs have been and will continue to contribute to the utilities' capacity needs, which justifies paying existing QFs a capacity payment. This will recognize the capacity value they provide when they renew their contracts regardless of the utilities' resource position. The Idaho Commission requires capacity payments to existing QFs during the resource sufficiency period because they provide capacity value to the utilities during all years and are expected to continue to sell power to the utilities.

Q. Are small and existing projects contributing to the utilities' alleged problems?

A. No. Assuming that all of PacifiCorp's alleged problems are true, these problems are not being caused by existing and small QFs. Nearly all the new QF contracts are new wind and solar generation resources. The Commission's final order in this proceeding should be careful not to harm those QFs that are not contributing to the problems faced by PacifiCorp.

Q. Would changing PURPA policy to include a three-year or another short contract term harm these existing and small projects?

A. Yes. Currently, small QFs can enter into a twenty-year contract term but typically enter into terms which align with fixed prices, such as 15-years in Oregon. New projects certainly need the longer term in order to meet debt requirements. Even existing projects require long term agreements for system improvement projects, planning and financing. This is especially true for QFs that are part large water conveyance systems, such as irrigation districts. There are other reasons why longer-term agreements are necessary, one of which is the avoidance of market based or lower energy prices during periods of resource sufficiency. A three-year (or other short) term limit on existing projects is problematic in terms of continuous renewal of contracts and exposes the QFs much lower prices (total value) than would result from a single long-term contract.

Renegotiating contracts can be time consuming and costly, especially for small and existing QFs, and could be expected to be very burdensome if required every three years. Small existing facilities rarely have the option of selling their power to other entities, and typically only have the choice of continuing to sell their power to their interconnected utility or shutting down. Also, since existing QFs, especially small hydro projects that are Federal Energy Regulatory Commission licensed or exempted are not going mobile, there is no need to place a significant burden and the cost of constantly entering into new short-term contracts. These projects were planned for and can be expected to continually operate and deliver power to their interconnected utility, provided the price warrants continued operation.

Slashing the contract term for small QFs is unnecessary, would also harm the utilities and ratepayers, and is unproven as the proper response. Requiring the utilities to renegotiate all small QF contracts every three years, for example, would be costly for the utilities. These unnecessary costs would be passed on to ratepayers.

Q. Would the practical result of PacifiCorp's short contract terms result in QFs never or almost never being paid for capacity?

A. Yes. PacifiCorp's proposal for short contract terms means that there will always be a period of resource sufficiency, which would likely result in QFs never being paid for their capacity. If the resource sufficiency period is short and the contract term is limited to a few years, then projects will no longer receive capacity payments because the next capacity deficit will normally be more outside the period of the contract term.

Q. Can you provide an example?

A. Yes. If there are short contract terms, QFs will not be paid for capacity if they enter into a contract term that expires prior to the time when the next thermal resource acquisition is planned.

For example, assume that PacifiCorp is planning its next thermal resource acquisition in four years (2019). Under PacifiCorp's proposal, a QF that enters into a new three-year contract in 2015 will not be paid for capacity during the entire contract term. In 2019, PacifiCorp would have a new IRP, and the next new thermal resource would be at least more than three years away; therefore, avoided costs would not have any capacity payments during this "sufficiency" period. And since a new thermal resource usually cannot be avoided in less than three years, resource sufficiency could be expected to be at least four to five years, as demonstrated by previous avoided cost filings.

If the QF renews its contract and enters into a new three-year contract in 2019, then the QF will again not be paid for capacity. The QF could continue entering into renewing contracts for the rest of its useful life, but never be paid for capacity. The QF will have caused PacifiCorp to reduce both its energy and capacity needs (including the capacity related to the next planned thermal resource), however, the QF will not be paid for capacity under the company's approach.

This example highlights the extreme unfairness of PacifiCorp's proposed three-year contract term. If contract terms are shortened to five or ten years, then similar problems could continue to exist. As long as the contract term is shorter than the resource sufficiency period and resource sufficiency period prices do not include capacity payments, then the QFs will not be paid for capacity.

Even when the contract term is a few years longer than the sufficiency period, QFs would not be fairly treated. For example, with a nine-year "sufficiency" period, and ten-year contract term, then the QF would be paid only one year of capacity in the last year of its contract. When the QF entered into its new contract, it would suddenly stop being paid capacity in at least the first years of its new contract. Assuming another nine-year sufficiency period and ten year contract, then the QF would only be paid only one year of capacity in this second contact, and only two years of capacity over a twenty year period. The unfairness and unevenness of capacity payments can be resolved if avoided cost rates would recognize, that once a project is on-line providing capacity, then it does so continuously just like a utility's own resources. Short-term contracts make the payment and recognition of capacity value very problematic.

IV. EXISTING QFS SHOULD BE PAID CAPACITY

Q. If the Commission shortens the contract term, do you have any recommendations?

A. Yes. All existing projects seeking a replacement of a firm contract should continue to receive capacity payments or value for capacity. The continuum of payment for capacity should remain uninterrupted once a project comes on line and delivers during a resource deficiency period.

Q. Does PacifiCorp rely upon renewing QFs capacity?

A. As part of the IRP process, PacifiCorp assumes that small QFs renew their contracts, which provides capacity value to the company and its ratepayers. This assumption is reasonable because nearly all of these QFs do not have other alternatives to sell their power, and they reliably renew their contracts, particularly hydroelectric projects. Existing QFs help defer new capacity resources since the utilities plan on them selling power after the expiration of their contracts. PacifiCorp agrees that existing QFs help defer its next capacity resource because the "capacity contribution of all signed QF contracts executed subsequent to the development of the IRP preferred portfolio reduce the deferrable capacity of the next avoidable resource . . . ." Re Investigation into QF Contracting and Pricing, Oregon PUC Docket No. UM 1610, PAC/100, Dickman/15.

Existing QFs are essentially providing this capacity, effectively for free, through their assumed contract renewals when avoided cost rates are based on market prices. If PacifiCorp's proposal is adopted, then existing QFs will provide this capacity for free during the entire life of their project.

Avoided cost rates should reflect that existing QFs provide capacity value by helping to defer the utilities' need to buy or build new capacity resources. Existing QFs have also not caused any projected short-term surplus and should not be penalized in the form of reduced capacity value in a subsequent follow-on contract.

The solution is that existing QFs entering into follow-on contract extensions should be provided full avoided cost pricing based on the avoided resource cost each and every year. To not provide full avoided resource cost payments to QFs in follow-on contracts would be inequitable as compared to the treatment afforded utility-owned resources.

Q. Are you aware of how capacity payments are addressed in other jurisdictions?

A. Yes. The Idaho Commission provides that renewing QFs are not subject to a sufficiency period. The decision states:

> By including a capacity payment only when the utility becomes capacity deficient, the utilities are paying rates that are a more accurate reflection of a true avoided cost for the QF power. However, we find merit in the argument made by the Canal Companies that contract extensions and/or renewals present an exception to the capacity deficit rule that we adopt today. It is logical that, if a QF project is being paid for capacity at the end of the contract term and the parties are seeking renewal/extension of the contract, the renewal/extension would include immediate payment of

> capacity. An existing QF's capacity would have already been included in the utility's load resource balance and could not be considered surplus power. Therefore, we find it reasonable to allow QFs entering into contract extensions or renewals to be paid capacity for the full term of the extension or renewal.

Re the Commission's Review of PURPA QF Contract Provisions, IPUC Case No. GNR-E-11-03, Order No. 32697 at 21-22 (emphasis added) (Dec. 18, 2012) clarified in Order No. 32871 (Aug. 9, 2013).

The Idaho Commission specifically reaffirmed that policy in its most recent order in Docket GNR-E-15-01 lowering the contract term. Re Idaho Power Company's Petition to Modify Terms and Conditions of PURPA Purchase Agreements, IPUC Case Nos. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03, Order No. 33357 at 25-26 (Aug. 20, 2015). The Idaho Commission explained that if it lowered the contract term without paying QFs for capacity during the sufficiency period, then QFs would never be paid for capacity due to the fact that the sufficiency period exceeds the contract term. Existing QFs that renew their contracts would continue to be paid capacity during the sufficiency period, and new QFs that signed contract would be paid capacity in most of the years for renewal contracts. The Idaho Commission explained that:

> We recognize that a new two-year contract would be unlikely to reach a capacity deficiency date. Therefore, we find it reasonable for utilities to establish capacity deficiency at the time the initial IRP-based contract is signed. As long as the QF renews its contract and continuously sells power to the utility, the QF is entitled to capacity based on the capacity deficiency date established at the time of its initial contract. For example, if the QF comes on-line in 2017 and the utility is capacity deficient in 2020, the QF would be eligible for capacity payments in the second year of its second contract and thereafter if in

> continuous operation. This adjustment recognizes that in ensuing contract periods, the QF is considered part of the utility's resource stack and will be contributing to reducing the utility's need for capacity. This mitigates the concern that short-term contracts will not contribute to the avoidance of utility capacity/generation.

Id.

This Commission should make the same determination regarding capacity or fixed payments for renewing QF. Existing QFs entering into follow-on contracts should be provided avoided costs prices with no sufficiency period.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes

Oregon Public Utility Commission

Docket No. UM 1734, Response Testimony of Jeremiah Camarata and Edson Pugh

Oct. 15, 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1734

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Application to Reduce the Qualifying Facility	)
Contract Term and Lower the Qualifying	)
Facility Standard Contract Eligibility Cap	)
	)
	)

RESPONSE TESTIMONY OF

JEREMIAH CAMARATA AND EDSON PUGH

ON BEHALF OF

THE RENEWABLE ENERGY COALITION

October 15, 2015

Q. Please state your name and business address.

A. My name is Jeremiah Camarata. I am the District Manager at Farmers Irrigation District ("FID"), which is a member of the Renewable Energy Coalition (the "Coalition"). My business address is Farmers Irrigation District, 1985 Country Club Road, Hood River, OR 97031.

My name is Edson Pugh. I am the General Manager at Deschutes Valley Water District ("DVWD"), which is a member of the Coalition. My business address is Deschutes Valley Water District, 881 S.W. Culver Highway, Madras, OR 97741.

Q. Mr. Camarata, please describe your background and experience.

A. I have worked for private, non-profit, and public water resource-based entities since 2003. Before that, I grew up on farmland, earned degrees from prominent universities, and travelled some of the world. For over the last twelve years, I have served farmers, ranchers, and urban water users alike, and have worked diligently towards water and power efficiencies that create jobs, benefit the environment, and serve the common good. I have a Masters degree in Landscape Architecture, serve as the Chair of the Oregon Water Resource Congress Hydropower Caucus, and am currently responsible for delivering water to ~5,900 acres of high value agricultural land. My district's mission is to support this important economy by promoting ecologically, socially, and financially sustainable agriculture by providing energy and irrigation service for the common good. A further description of my educational background and work experience can be found in Exhibit Coalition/201 in this proceeding.

Q. Mr. Pugh, please describe your background and experience.

A. I have worked for Deschutes Valley Water District for about 30 years as the district's engineer, the last 11 years as the general manager and engineer. I have been a registered professional engineer since 1990. Our district's mission is to provide safe and good tasting drinking water at a reasonable cost to existing and future DVWD patrons while continuing a high level of customer service.

A further description of my educational background and work experience can be found in Exhibit Coalition/202 in this proceeding.

Q. On whose behalf are you appearing in this proceeding?

A. We are testifying on behalf of the Coalition in this Oregon Public Utility Commission (the "Commission" or "OPUC") proceeding.

Q. Have you previously testified before the Commission?

A. Yes, we submitted similar testimony in Phase I of Docket No. UM 1610.

Q. What topics will your testimony address?

A. Our testimony will provide background information about FID and DVWD (jointly, the "Districts"), our hydroelectric projects which sell power to PacifiCorp as qualifying facilities ("QF"), as well as address PacifiCorp's proposal to lower the size threshold for wind and solar contracts from 10 megawatts ("MW") to 100 kilowatts ("kW"), and shorten the contract term for all QFs from twenty years to three years.

<u>FARMERS IRRIGATION DISTRICT PROJECT AND CONTRACT SPECIFICS</u>

Q. MR. CAMARATA, PLEASE DESCRIBE FID.

A. FID, a nonprofit government agency founded in 1874, is located in Hood River, Oregon, in the beautiful, culturally rich Columbia River Gorge. Water is provided to ~5,900 acres of land and 1,860 customers, both residential and agricultural. Hood River County is known for its orchards and depends heavily on their production of pears, apples, and cherries for economic vitality. The county produces more winter pears than any county in the United States and the annual economic footprint of agriculture in Hood River County was estimated at $306 million in 2009. FID's mission is to support this economy by promoting ecologically, socially, and financially sustainable agriculture by providing energy and irrigation service for the common good.

FID has nine primary water diversions, all of which are run-of-the river (no dams on free flowing rivers and creeks) and protected by state of the art head works and our patented fish friendly Farmers Screens approved by National Oceanic and Atmospheric Administration ("NOAA") fisheries. Having received state and federal agency approval for The Farmers Screen, we patented the technology and now license it to the Farmers Conservation Alliance with the condition that profits be used for the united benefit of fish, farms, families, and the environment. The screen investments have dramatically stabilized and increased our hydro production while saving farmers hundreds of thousands of dollars per year. These technologies and concepts extend to many other water districts in the state and beyond. We are proud of our century-long efforts in innovative efficiencies and environmental protection and plan on continuing to be the leaders in irrigation management by aggressively raising the bar in sustainable agriculture, power production, fish screening standards, and water conservation measures into the foreseeable future.

Since implementation of hydropower production capabilities in the mid-eighties, our district has made over $40 million in capital improvement projects that create and maintain jobs, and support the community and environment. None of this would be possible without dependable, fair, long-term power-sales agreements. Continuation of power-sales agreements that are dependable, fair, and long-term in nature are absolutely critical to our operational budgets, commitments to agriculture, long-term debt service owed to private, state and federal entities, necessary investments in critical water conveyance infrastructure, and the entire fabric of community and commerce that have come to depend on us as a public entity.

Q. Mr. Camarata, please describe your QF project.

A. FID owns, operates, and maintains a hydroelectric facility for the generation of electric power, including interconnection facilities, located in Hood River Oregon (within the region covered by the Western Electricity Coordinating Council) with a Facility Capacity Rating of 4.8 MW. FID sells its net output directly to PacifiCorp and the associated, unbundled renewable energy credits ("RECs") to various other public and private entities under renewable portfolio standard ("RPS") mandates or to those generally concerned about their carbon footprint and or climate change. Generating renewable electricity from local water systems has been a critical component of FID daily operations since the mid-eighties. FID has two turbine and generator sets. FID power plants are modern and utilize sophisticated equipment and technology. In fact, in 2015 FID made ~$4.96 million in hydropower upgrades. FID generators produce an approximate average of 26,000 MWh per year. With our many capital improvement projects, infrastructure rehabilitation efforts, innovation, and water conservation measures implemented over time, our production is stable year-round.

Q. Mr. Camarata, please describe your current QF contract with PacifiCorp.

A. FID's current contract term became effective on January 1, 2011, and shall terminate on December 31, 2025. Contract prices are paid for on-peak and off-peak production. This contract replaces the original contract of 25 years which expired on December 31, 2010. The original contract contained both energy and specific capacity payments. The current contract applies limited levelization of prices to help FID in minimizing severe cash flows mainly caused by resource sufficiency year avoided cost pricing under Schedule 37 and the non-payment for capacity during such sufficiency years. Had FID continued to receive capacity payments for the sufficiency years 2011 through 2013, the levelization of prices under our 2010 power purchase agreement would have been unnecessary.

FID also has a separate interconnection agreement that was just recently executed in 2015.

Q. Mr. Camarata, did FID recently make signficant upgrades at its facility?

A. Yes. As stated above, FID made ~$4.96 million in hydropower upgrades in 2015.

DESCHUTES VALLEY WATER DISTRICT PROJECT AND CONTRACT SPECIFICS

Q. Mr. Pugh, please describe DVWD.

A. DVWD is a government agency and special district as defined by ORS § 264. DVWD is a public water supplier to approximately 5,000 service connections to residential, commercial, and industrial customers in the communities of Culver, Metolius, Madras, and their surrounding areas in Jefferson County, Oregon.

DVWD's hydro-electric plant is integral to the District's mission in keeping water rates reasonable and funding capital improvement projects for the water system infrastructure. DVWD's service area is over 23 miles long and is served by over 400 miles of pipelines.

Q. Mr. Pugh, please describe your QF project.

A. DVWD owns, operates, and maintains the Opal Springs hydroelectric facility for the generation of electric power, including interconnection facilities, located in Jefferson County, Oregon (within the region covered by the Western Electricity Coordinating Council) with a Facility Capacity Rating of 4,300 kW. DVWD sells its net output directly to PacifiCorp and the associated, unbundled RECs to various other public and private entities under RPS mandate who are voluntarily concerned about carbon footprint and climate change. Opal Springs Hydro is a "run of the river" low head hydro-electric facility with a single generator driven by a Kaplan turbine. Power production is consistent on a monthly basis with extra production during spring run-off. The plant usually produces over 360 days per year.

Q. Mr. Pugh, please describe your current QF contract with PacifiCorp.

DVWD's current thirty-five-year term contract was executed in 1982 with power deliveries to begin January 1, 1985 and it shall terminate December 31, 2020. This original contract contains both energy and specific capacity payments based upon demonstrated capacity, and further is the original type of non-bifurcated power purchase and interconnection agreement. We will likely need to negotiate a new interconnection agreement before our current contract expires.

<u>THE 10 MW SIZE THRESHOLD SHOULD NOT BE REDUCED</u>

Q. Do you support keeping the Commission's current 10 MW size threshold for all QFs?

A. Yes.

Q. Why are you testifying about the size threshold for wind and solar when your projects are hydro-electric?

A. We are concerned that PacifiCorp may request to lower the size threshold for other resoruces like hydro-electric in the future. We are providing information that may be helpful in understanding why the size threshold is important for all QFs. In addition, we are concerned that the Commission may lower the size threshold for all QFs, even though PacifiCorp has only requested a lower size threshold for wind and solar QFs. In no circumstance should the Commission lower the size threshold for baseload QFs like hydro-electric projects.

Q. What is the importance of being under the size threshold?

A. The primary reason is to avoid being subject to extremely costly negotiation of replacement power purchase agreements (that are not based upon known published prices), including highly variable prices and short contract terms. The Districts do not have the expertise nor resources to negotiate such prices and terms without significant third-party assistance and expense. Further, it has been experienced, and is expected that such agreements can not be reasonably met without significant time delays, cost, controversy, and risks associated with fluctuating prices and terms.

Q. Arguments have been made that many QFs are large, sophisticated energy developers. Does this apply to your facilities?

A. Absolutely not. Although the Districts may be relatively large in terms of acreage and end-users of water and other delivered resources, our primary business is not the development of energy producing projects. Our primary focus is the continued operation of the critical water systems needed to serve our communities. Maintaining the safe and reliable nature of our current hydroelectric projects is extremely important, but we are in the water delivery service sector.

Q. How important is it to avoided delays and have an expeditious contract completion process?

A. Extremely important, for several reasons.

Under the current Schedule 37 process, in PacifiCorp's case, little negotiation should be necessary to complete the power purchase agreement since it is essentially a "fill-in-the-blanks" form agreement. Then current published prices are added to the agreement as an exhibit. Provided that avoided cost prices are not in the process of changing and there are not other obstacles, the agreement should be able to be executed within a couple of months. We have been informed that the negotiation process even for standard contracts can take much longer. In any event, the successful completion of the agreement is more assured in the standard contract process than if all terms and prices must be negotiated. This is not the case with negotiated contracts which include negotiated prices whose basis or beginning point is subject to constant change. We are not large, sophisticated energy developers, nor can we afford to waste or justify taxpayer dollars on non-expeditious process in which we have very little expertise.

THE COMMISSION SHOULD MAINTAIN THE CURRENT CONTRACT DURATION AND CAPACITY PAYMENTS

Q. What are the Commisison's current requriemetns regarding contract terms?

A. QFs should have the option to select contracts of up to 20 years, with fixed prices for the first 15 years.

Q. Do you support the Commission's current policy?

A. We support the Commission's policy regarding a twenty (20) year contract term. The fixed price period of 15 years is adequate, and necessary to facilitate the long-term planning of the hydro operations in context with other planning associated with the water systems that we operate. This includes financing needed to make system improvements, repairs, and meet or exceed environmental requirements. We do not support the Commission's current policy which does not allow existing QFs that enter into renewal contracts to be paid for the capacity value they provide to PacifiCorp. Given the long resource sufficiency periods, this policy has the practical impact of causing existing QFs to not be paid for capacity during the majority of their contract years, even if they enter into a fifteen year contract.

Q. What has PacifiCorp proposed?

A. Three year contract terms for all QFs.

Q. Do you support PacifiCorp's proposal?

A. No. Three (3) year contracts would put us out of business and jeopardize decades worth of conservation effort and threaten future reliability of critical water delivery systems to the public. Existing QFs such as our water districts would be required to enter into short term three-year contracts likely entirely based on resource sufficiency based prices with low market rates, without capacity payments. Even if a QF is willing to obligate itself for a longer period of time and provide needed capacity to the utility, the QF would not receive fixed prices or capacity payments. Under existing policy, an existing QF can at least enter into a 15-year contract and obtain fixed payments, including capacity during the resource deficiency years.

Q. Do existing QFs need long term contracts in order to obtain project financing?

A. Absolutely. Our existing projects are part of a large complex of integrated facilities that deliver critical irrigation and drinking water to citizens, businesses, and animals. In order to financially plan, engineer, build and operate these systems, including the hydro projects, it is necessary to incorporate long-term financing. Even with a 15-year power contract term, it is absolutely necessary to have long-term financing in place that exceeds such term. Short-term contracts of three years would make long-term planning nearly impossible, and very risky for District finances. Short-term contracts would also handicap our ability to provide and maintain safe infrastructure and reliable water supply to citizens, including but not limited to large and small agri-business. We have a hard enough time getting projects financed with the current contract criteria. A contract term of 3 years is not long enough for a project to pay for itself. Imagine the size of your monthly payment if you had to buy a house or a car with a 3 year note and then imagine how many banks would be interested in making a loan with those payments—I am sure you realize that the answer is: next to none.

Q. Do existing QFs needs to make capital improvements?

A. Yes, and in most cases capital improvement projects are going on continuously. Responsible water districts and suppliers typically have a substantial annual ongoing capital improvement and safety program that relies on long-term debt. District water systems are expensive to maintain and large piping and other capital improvement projects are critical to supporting the needs of a growing society dependent on water and agriculture. Capital improvements rely on long-term debt financing and our ability to meet debt service. Long-term financing necessary to maintain safe and aging infrastructure is not only critical to saving and protecting lives, but simply the responsible thing to do.

Q. Do existing QFs need pricing stability?

A. Price stability and certainty for current and potential new power purchase agreements is of utmost importance. Pricing stability and certainty are essential for reliable water service. For districts with existing contracts, reliability on power purchase agreement pricing is commensurate with water being available out of the faucet at your home, or not.

Q. Why is it important for a QF to not renegotiate a contract every three years?

A. In addition to the reasons above, frequent renegotiations would harm our ability to make long-term plans that rely upon stable prices. Entering into a standard power purchase agreement every three years would be beyond challenging, and subject Districts and their patrons to unnecessary costs, risks, harm, and even the re-opening of interconnection agreements (which are also extremely difficult and costly to execute). Changing the standard price and contract threshold to a lower level, thereby requiring the Districts to negotiate pricing and contracts every three years would be draconian, and a complete waste of taxpayer dollars. The Districts should not be subjected to perpetual and wasteful negotiation that would ultimately harm the public whom depends upon reliable water service.

Q. Does a three-year term harm a QF's ability to sell its RECs?

A. Yes. In addition to generating power, the electrical generation output of our projects also produces non-energy environmental, economic and social benefits. Some of these separate non-energy benefits are called "green tags," "tradable renewable certificates," and "RECs," which can be sold on the market to third parties or the utilities themselves. Purchasers of these non-energy attributes often wish to enter into long-term contracts in excess of ten years. Based on our personal experience, we believe that we can procure greater sales opportunities and obtain much higher and more stable prices if we can enter into contracts for periods greater than three years. However, we may not be able to agree to sell the non-energy benefits under a long-term contract if we can only enter into a three-year contract to sell our electricity to the utility. Therefore, a short three-year contract can cause significant and unnecessary harm to a QF's ability to sell the non-energy attributes. We are more than willing to develop our own innovative ways to realize a premium on our power production, but allowing sufficient and fair rates over a reasonably long time period to support and plan our projects with base production revenue is absolutely paramount.

Q. Does this conclude your testimony?

A. Yes.

Oregon Public Utility Commission

Docket No. UM 1725, Response Testimony of John Lowe

Jul. 31, 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1725

In the Matter of	)
	)
IDAHO POWER COMPANY,	)
	)
Application to Lower Standard Contract Eligibility Cap and to Reduce the Standard Contract Term, for Approval of Solar Integration Charge, and for Change in Resource Sufficiency Determination.	))))))

RESPONSE TESTIMONY OF

JOHN R. LOWE

ON BEHALF OF THE

RENEWABLE ENERGY COALITION

July 31, 2015

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John R. Lowe. I am the director of the Renewable Energy Coalition (the "Coalition"). My business address is 12040 SW Tremont Street, Portland, Oregon 97225.

Q. Please describe your background and experience.

A. In 1975, I graduated from Oregon State with a B.S. I was employed by PacifiCorp for thirty-one years, most of which was spent implementing the Public Utility Regulatory Policies Act ("PURPA") regulations throughout the utility's multi-state service territory. My responsibilities included all contractual matters and supervision of others related to both power purchases and interconnections. Since 2009, I have been directing and managing the activities of the Coalition as well as providing consulting services to individual members related to both power purchases and interconnections.

Q. On behalf of you are you appearing in this proceeding?

A. I am testifying on behalf of the Coalition.

Q. Please describe the Coalition and its members.

A. The Coalition was established in 2009, and is comprised of thirty members who own and operate nearly fifty non-intermittent small renewable energy generation qualifying facilities ("QFs") in Oregon, Idaho, Montana, Washington, Utah, and Wyoming. Several types of entities are members of the Coalition, including irrigation districts, water districts, corporations, and individuals. Except two, all are small hydroelectric projects.

Q. What are the Coalition's interests in this proceeding?

A. The Coalition has a number of key interests in this proceeding. First, our goal is to ensure fair and reasonable contract terms and conditions, and avoided cost rates for small projects under the standard contract and rate eligibility cap. Second, the Coalition's members are primarily existing QFs, and our goal is to ensure that any final order in this proceeding recognizes and accounts for the unique circumstances and benefits of existing projects. Finally, the Coalition recognizes that PURPA must work to benefit all interested parties, including the utilities, ratepayers, and new and existing QFs of various sizes. The Coalition's goal is that PURPA policies account for all these interests, and the changes (if any) adopted by Oregon Public Utility Commission (the "Commission") are narrowly tailored to resolve specific problems. Any policy changes should not unduly harm any one, especially parties not causing the problems that led to the utilities' filings.

Q. Please summarize Idaho Power's requests in this case.

A. Idaho Power has requested: 1) to lower the standard contract eligibility cap to 100 kW for wind and solar QFs; 2) to lower the standard contract term to two years for wind and solar QFs; 3) approval of a solar integration charge; and 4) to change its resource sufficiency determination.

Q. Please summarize your testimony.

A. The alleged problems facing Idaho Power are exaggerated, and the problems (if any) are not caused by baseload QFs, and any policy changes (if any) that result from these proceedings should exempt baseload projects. Second, I explain the unique reasons why that there should be no change in policy for existing projects. Existing projects are also not causing any problems, and in fact are providing significant benefits to the utilities. In addition, imposing a policy change like a shortened contract term on existing QFs could have significant and unnecessary harm on these projects, the utilities, and ratepayers.

Q. What are your specific responses to Idaho Power's filings?

A. First, the Commission should not lower the size threshold or contract terms for any QFs. However, if the Commission lowers the size threshold or contract terms, then it should not apply to baseload QFs, which is consistent with Idaho Power's recommendation in this case. Second, the Commission should not change Idaho Power's resource sufficiency period or capacity deficit at this time. Third, the Coalition has no position on Idaho Power's solar integration charge at this time.

II. CONTRACT TERM AND SIZE THRESHOLDS SHOULD NOT BE REDUCED

Q. Please describe the alleged problems facing the Idaho Power.

A. Idaho Power has supported its request to reduce the contract term with claims regarding the harm caused by new large wind and solar QFs. For example, Idaho Power states that they have a large amount of new wind and solar projects under contract, and a large number of additional wind and solar QFs seeking new contracts. Idaho Power alleges significant customer rate and reliability concerns associated with this large amount of large wind and solar QFs.

Q. Do you agree with Idaho Power that they are facing significant problems associated with new PURPA projects?

A. I agree that Idaho Power is facing a large number of new contract requests and new contracts. This is a legitimate issue that warrants consideration.

In my experience, not all of the QFs that request contracts, or that even enter into contracts, ever come on line. I worked at PacifiCorp after PURPA was passed and in the early years there was a huge number of new requests for hydroelectric projects, and only a small fraction were developed. Over my years at PacifiCorp, very few of the projects that sought contracts, or even of those that signed contracts, eventually became operating and selling electricity.

Utilities like Idaho Power also typically over estimate the costs and harms associated with QFs, and underestimate their benefits. Utilities do not earn a return on purchases from QFs, and often allege that they harm ratepayers even when QFs are a lower cost and more reliable source of power than the market or the utilities' own generation resources.

In any event, these problems are not caused by baseload projects under the current standard contract rate threshold. I will address this later in my testimony.

Q. Do you have any indication that Idaho Power's potential problems may be exaggerated?

A. Yes. Idaho Power has a history of exaggerating the level of expected new QFs. In 2012, Idaho Power claimed it was facing a "deluge" of over 70 MWs of new Oregon wind QFs. This deluge quickly dried up with Idaho Power entering into far fewer contracts. I am not aware of any of these operating.

Idaho Power now states that it entered into 461 MWs of new solar generation in Oregon and Idaho. Application to lower standard contract eligibility cap and to reduce the standard contract term ("Application") at 1-2. Idaho Power, however, admits that almost a third or 144 MWs have already had their contracts terminated. Idaho Power also alleges that it currently has an extraordinary level of requests for new PURPA contracts, including "additional 1,326 MW of solar capacity actively seeking PURPA contracts, 245 MW of which are in Oregon." Application at 2.

Despite these potential contracts, there are a number of reasons why this new solar generation may not occur. For example, it appears that Idaho Power no longer has much available transmission capacity, and any new QFs will be required to pay for expensive transmission upgrades. Specifically, Idaho Power states:

> The five Oregon Qualifying Facility ("QF") wind projects and the six Oregon QF solar projects will require network transmission upgrades for network transmission service. These projects will use all of the incremental transmission capacity from their respective network transmission upgrades leaving no transmission capacity for additional generation projects, regardless of size, in this area of Idaho Power's transmission system.

It is extremely unlikely that Idaho Power will have sufficient available interconnection and transmission capacity to accommodate a large amount of any type of new generation, especially given the current the historically low avoided cost rates. Transmission issues alone could put a sudden halt to much of the potential QF development. In addition to transmission issues, there are the traditional forces related to project financing, ordinary risks of development, interconnection costs, utility hostility, and many other factors that will reduce the number of projects that are eventually constructed.

Q. How should the Commission address the alleged problems facing Idaho Power?

A. The Commission should reject Idaho Power's proposal to lower the size threshold and standard contract term for wind and solar QFs. Alternatively, if the Commission is inclined to adopt any relief, then it should not apply to small or existing baseload QFs. This alternative recommendation is consistent with Idaho Power's recommendation that relief be limited to wind and solar QFs.

Q. Please describe what you mean by projects under the standard contract rate threshold.

A. The standard contract rate eligibility threshold is the maximum size for a QF to be eligible to sell power at a utility's published avoided cost rates. The current rate eligibility cap is 10 megawatts ("MW") for all generation resources, except there is a temporary 3 MW cap for solar generation.

Q. Is the standard contract and rate threshold important?

A. Yes. It is much more difficult for QFs to negotiate contracts over the rate eligibility cap than those below the cap. All states that I work in allow smaller QFs to obtain published rates instead of negotiating rates or having their rates determined by a utility computer model.

Q. Why are small projects treated differently than larger projects?

A. There are a number of important reasons for treating smaller projects differently, some which include developer sophistication, transaction costs, economies of scale, and the inability to economically access alternative markets. It is important to recognize the unique difficulties facing smaller projects, and allowing smaller projects to sell power at a published rate helps mitigate some of these difficulties.

Negotiating contracts can be costly in terms of upfront transactional costs. Small QFs do not typically have in house attorneys and experts with the skills to assist in the evaluation and negotiation of contracts. Therefore, they often need to hire outside experts. In addition, negotiating a QF contract with a utility can take a great deal of time. All of these transactional costs can impose significant economic burdens, and even make a smaller project uneconomical.

Most small projects also do not have the options available to larger projects. This is especially true for small hydro, geothermal and many biomass projects. For example, large scale resources developed by utilities or large independent power producers benefit from being sized so that the dollar-per-kilowatt investment required to build the plant is less than for a much smaller sized QF of the same basic technology. Similarly, it is my understanding that the typical short-term power sale trades in the Pacific Northwest electricity market are for blocks of 25 MW power, and small QFs cannot effectively participate in this market.

Q. Please explain what you mean by existing QFs?

A. Existing QFs are those projects that are already operating and are generally selling power to the interconnected utility. Some of these projects have been operating since the mid 1980s.

Existing projects face some unique challenges. Existing projects must enter into a replacement power purchase agreement ("PPA") when their current

PPA expires. In Oregon, this always means that their new PPA starts during a term that includes an initial period of utility resource sufficiency. Most existing projects have been operating for years, and may require major replacement and/or upgrading of their equipment, conveyance structures and other facilities including interconnections. New interconnection agreements are often required. There can be significant costs involved in addressing these needs or requirements

Q. Are existing QFs treated differently than new QFs?

A. Yes. For example, existing QFs are included in the utilities' resource plans. These QFs have been and will continue to contribute to the utilities' capacity needs, which justifies paying existing QFs a capacity payment that recognizes their capacity value when they renew their contracts regardless of the utilities' resource position. California and Idaho require capacity payments to existing QFs during the resource sufficiency period to recognize that they provide capacity value to the utilities during all years and are expected to continue to sell power to the utilities.

Q. Would changing PURPA policy to include a two-year or another short contract term harm these existing and small projects?

A. Yes. Currently, small QFs can enter into a twenty-year contract term (the last five years are based on market prices).

Renegotiating PPAs can be time consuming and costly, especially for small and existing QFs, and could be expected to be very burdensome if required every five years or less. As I explained above, small existing facilities nearly always do not have the option of selling their power to other entities, and typically only have the choice of continuing to sell their power to their interconnected utility or shutting down. Also, since existing QFs, especially small hydro projects that are FERC licensed or exempted are not going mobile, there is no need to place a significant burden and the cost of constantly entering into new short-term contracts.

Significantly shortening the contract term for small QFs would also harm the utilities and ratepayers. It is my understanding that that small hydroelectric QFs below the rate eligibility cap make up the majority of Idaho Power's overall system individual PURPA projects. According to Idaho Power, small hydroelectric projects make up 68 of the total 133 that utility's PURPA projects under contract. Requiring the utilities to renegotiate all of these small QF contracts every two years, for example, would be costly for the utilities. These unnecessary costs would be passed on to ratepayers.

Q. Would the practical result of Idaho Power's short contract terms result in QFs never or almost never being paid for capacity?

A. Yes. Idaho Power's proposal for short contract terms means that there will always be a period of resource sufficiency, which may prevent QFs from being paid for capacity. If the resource sufficiency period is short and the contract term length is limited to a couple or few years, then projects will no longer receive capacity payments because the next capacity deficit will normally be more than the contract term.

Q. Can you provide an example?

A. Yes. Under Idaho Power's proposal, QFs will not be paid for capacity if they enter into a contract when the next thermal resource acquisition is in longer than the contract term. For example, assume that Idaho Power is planning its next thermal resource acquisition in three years (2018). Under Idaho Power's proposal, a QF that enters into a new two-year contract in 2015 will not be paid for capacity during the entire contract term. In 2018, Idaho Power will have a new IRP, which will likely not be planning on a new thermal resource for more than two years, and its new avoided costs will not have any capacity payments during this "sufficiency" period. If the QF renews its contract and enters into a new two-year contract in 2018, then the QF will again not be paid for capacity. The QF could continue entering into renewing contracts for the rest of its useful life, but never be paid for capacity. The QF will have caused Idaho Power to reduce both its energy and capacity needs (including the capacity related to the next planned thermal resource), however, the QF will not be paid for capacity under the company's approach.

This example highlights the ridiculousness of Idaho Power's proposed two year contract term. If contract terms are shortened to five or ten years, then similar problems will exist. As long as the contract term is shorter than the resource sufficiency period, then the QFs will not be paid for capacity.

Q. Are small and existing projects contributing to the utilities' alleged problems?

A. No. Assuming that all of the utilities alleged problems are true, these problems are not being caused by existing and small QFs. Idaho Power should be commended for recognizing this fact when it requested that its relief only apply to wind and solar. It is appropriate for any utility when seeking a change in policy to narrow its requested relief in a manner that solves the particular problem and does not cause unintended consequences. Idaho Power took the first step in only directing its relief toward those QFs that are arguably causing problems. While I disagree that the potential problems alleged by Idaho Power warrant any relief, I appreciate that Idaho Power at least recognized that small and existing baseload QFs benefit rather than harm ratepayers.

For example, the hydroelectric projects under the rate eligibility cap provide only 154 megawatts of the total current 1,302 megawatts of PURPA nameplate generation. While there is a large number of QFs under the published rate eligibility cap, the total megawatt size of these existing projects is small and not causing the alleged rate or reliability concerns identified by Idaho Power.

In fact, these projects provide Idaho Power with significant benefits. For example, many of these projects are seasonal, which means that they provide Idaho Power with valuable capacity. Limiting the contract length to these projects not only does not address the problems identified by Idaho Power, but may harm both Idaho Power and its ratepayers. The Commission's final order in this proceeding should be careful not to harm those QFs that are not contributing to the problems faced by the utilities.

II. CHANGE IN RESOURCE SUFFICIENCY AND DEFICIENCY PERIOD

Q. What is Idaho Power proposing regarding its resource sufficiency and deficiency period?

A. Idaho Power has requested a change in the demarcation between its resource sufficiency and deficiency period from 2016 to 2021.

Q. Why is this important?

A. The demarcation between resource sufficiency and deficiency also called the date of the next capacity deficit. This is something of a misnomer because the utilities often acquire capacity resources during their sufficiency period and the estimated resource sufficiency period is often overstated. Also, the integrated resource plan has little analysis regarding the correct demarcation regarding resource sufficiency and deficiency because the demarcation is typically outside of the Action Plan.

For avoided cost rate purposes, however, this demarcation is very important because during the period of resource sufficiency avoided cost prices are based on market purchases, and during the period of resource deficiency avoided cost prices are based on the costs of a thermal resource (or a renewable resource for the renewable avoided cost rates of PacifiCorp and Portland General Electric, but not Idaho Power). Thus, there is a relatively arbitrary and inaccurate date for a capacity deficit that has a huge impact on avoided cost rates.

Q. What is your recommendation?

A. The Commission should reject Idaho Power's request. Idaho Power's request is an out of cycle avoided cost update, and such updates previously have been disfavored by the Commission. The Commission has established policies for changing avoided cost rates, and Idaho Power's request to change to extend its resource sufficiency period without a acknowledged IRP update or acknowledgment of the new 2015 IRP is inconsistent with these policies.

Also, Idaho Power's request is unnecessary. Idaho Power has already filed its 2015 integrated resource plan, which may be acknowledged by the Commission shortly after this proceeding is completed. All of the discussion regarding capacity deficits and resource sufficiency periods in this proceeding may be an unnecessary waste of valuable utility, Commission, and QF resources. The utility's and Commission's costs are ultimately paid for by ratepayers.

Q. What is the Commission's established process for avoided cost rate changes?

A. The Commission has approved a process for changing avoided cost rates annually at a specific time (May 1) plus another potential update after IRP acknowledgement. The Coalition generally supports this process because it allows frequent avoided cost updates, but a more predictable avoided cost rate update schedule than under the Commission's previous ad hoc updates.

Recounting the history of why we have the current process may be helpful to understand why Idaho Power's proposed update should be rejected. By statute, avoided cost rate updates should occur every two years, and must happen in a manner that allows for a settled and uniform institutional climate for QFs. The Commission historically has allowed the utilities to update their avoided cost rates at least every two years coincident with the IRP process.

While the Commission had a two-year update policy, in practice parties have requested and sometimes obtained avoided cost rate updates more frequently than every two years. In other words, the Commission's standard two-year cycle was not consistently followed, which resulted in ad hoc updates that resulted in significant pricing uncertainty to QFs negotiating contracts with the utilities. This harmed QFs because predictability of price changes is one of the most important aspects of project development and continued operation, and unforeseen avoided cost updates can prevent a QF from successfully completing a contract. Unscheduled updates would completely upset a QF's plans to complete their negotiation process before a scheduled update will occur to obtain price certainty and not have their avoided cost rates significantly change in the middle of the negotiation process. QFs and the utilities have an asymmetrical level of information, including whether an update will increase or decrease the avoided cost rates.

Overall, unexpected updates have been an additional barrier to QF development and the utilities have used them as an opportunity to delay the negotiation process. The utilities have an incentive to delay the negotiation process or impose other barriers to finalizing a contract if avoided cost rates are declining, and the opposite incentive if avoided cost rates are increasing. This is exemplified by Idaho Power's actions in this case in which it delayed contract negotiations based on its knowledge that it planned to file its applications to lower avoided cost rates, size thresholds, and contract lengths.

In order to reduce these problems, the Commission adopted its current process of annual updates and an update after IRP acknowledgment (with the opportunity to waive one of the updates if they occur with in 60 days of each other). Docket No. UM 1610, Order No. 14-058 at 25-26. This protects ratepayers from outdated avoided cost rates, but also provides QFs with predictability and certainty regarding rate changes.

Q. Is Idaho Power's request to change the sufficiency period consistent with the Commission's policy on avoided cost updates?

A. No. Idaho Power's request to change its resource sufficiency period is what the Commission calls an "out of cycle update." The Commission also established guidelines regarding whether out of cycle updates should be allowed, stating that it would make it more difficult for parties to obtain updates outside of the normal process than in the past:

> we will continue to allow requests for mid-cycle updates for significant changes to avoided cost prices. However, in light of our decision here to require annual updates in addition to updates following IRP acknowledgement, we caution stakeholders that the "significant change" required to warrant an out-of-cycle update will be very high.
> We expect the parties to use this option infrequently.

Docket No. UM 1610, Order No. 14-058 at 25-26.

Q. Do you believe Idaho Power has met this "very high" standard?

A. No. I do not believe that Idaho Power has provided clear and convincing evidence to meet this "very high" standard for an early adjustment in its avoided cost rates. Idaho Power states that the early update is warranted because the inclusion of 440 MW of demand response would shift the capacity deficit to 2021 from 2016. I agree that both the size of the resource acquisition and the change from 2016 to 2021 by themselves could potentially be considered significant.

My concern primarily has to do with timing, and reviewing this change in isolation. Idaho Power filed an integrated resource plan on June 30, 2015. The IRP is supposed to be processed in a little over six months. OAR § 860-027-0400(10)(b).[1] I understand that IRPs have become more complex and can last over six months, but Idaho Power should have an acknowledged IRP early in 2016. This may be only a month or two after a final order in this proceeding. The Commission should not accept or approve a filing that is designed to result in a

[1] The rule reads: "Commission staff and parties must file any comments and recommendations with the Commission and present such comments and recommendations to the Commission at a public meeting within six months of the energy utility's filing of its request for acknowledgement of proposed change."

major avoided cost rate change only a month or two before the utility's IRP is acknowledged (which results in a new avoided cost rate change based on more complete information).

Q. Is there Commission precedent for rejecting Idaho Power's proposal?

A. Yes. Before the Commission established its current "very high" standard, it rejected a request by QFs to increase avoided cost rates after a dramatic increase in gas prices under a lower standard. At the time Idaho Power opposed the change because it was planning to file new avoided cost rates soon and the gas price change was only one factor among many that should be taken into account. This is similar to the current circumstances with Idaho Power planning to file updated avoided cost rates soon after the completion of this proceeding based on more than one factor.

In 2007, the Commission recognized that the facts of the situation would result in a major change in avoided cost rates and that "may warrant the updated avoided cost filings as contemplated by" its previous orders. Order No. 07-199 at 2. In other words, the Commission agreed that the avoided cost rates were going to updated soon and were inaccurate. Despite this, the Commission rejected the attempt to revise avoided cost rates early because the utilities would need to file new avoided cost rates soon.

The same rationale applies here. When Idaho Power made its filing, an annual avoided cost update was expected in only one week. Similarly, Idaho Power's avoided cost rates will need to be revised shortly after the completion of a final order in this proceeding to account for changes in the company's integrated resource plan. As Idaho Power explained in 2007, the IRP will account for a myriad of potential issues and more than just the additional demand response resources. The Commission should reaffirm that it will use the process of annual updates, and an update after IRP acknowledgement, and reject Idaho Power's proposed change in its resource sufficiency.

III. CONCLUSION

Q. Please summarize your testimony.

A. The Commission should reject Idaho Power's proposal to lower the size threshold and contract term for wind and solar QFs. In the alternative, if the Commission lowers the contract term to anything short of twenty years or size threshold to anything less than 10 MWs, whatever relief adopted should only apply to wind and solar QFs, as Idaho Power has requested. The Commission should not update Idaho Power's resource sufficiency period or capacity deficit in a stand alone proceeding because it would upset the expectations of QFs and it is unnecessary. Most importantly, allowing an avoided cost rate change in this proceeding would create a dangerous precedent and harmful uncertainty regarding when utility's can update their avoided cost rates. All of this would occur when it will have little practical impact.

Q. Does this conclude your testimony?

A. Yes

Federal Energy Regulatory Commission

Windham Solar LLC, 157 FERC ¶ 61,134

Nov. 22, 2016

157 FERC ¶ 61,134
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Colette D. Honorable.

Windham Solar LLC and Allco Finance Limited	Docket Nos.	EL16-115-000
Windham Solar LLC		QF16-362-002
Windham Solar LLC		QF16-363-002
Windham Solar LLC		QF16-364-002
Windham Solar LLC		QF16-365-002
Windham Solar LLC		QF16-366-002
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Windham Solar LLC		QF16-387-002

NOTICE OF INTENT NOT TO ACT AND DECLARATORY ORDER

(Issued November 22, 2016)

1. On September 12, 2016, as supplemented on September 26, 2016, Windham Solar LLC (Windham) and Allco Finance Limited (together, Petitioners) filed a petition for enforcement against Connecticut Public Utilities Regulatory Authority (Connecticut Authority) pursuant to section 210(h)(2)(B) of the Public Utility Regulatory Policies Act

of 1978 (PURPA).[1] Petitioners claim that the Connecticut Authority's August 24, 2016 final decision (Final Decision) violates the Commission's PURPA regulations regarding a qualifying facility's (QF) ability to sell pursuant to a legally enforceable obligation at a forecasted avoided cost rate.

2. Notice is hereby given that the Commission declines to initiate an enforcement action pursuant to section 210(h)(2)(A) of PURPA.[2] Our decision not to initiate an enforcement action means that Petitioners may themselves bring an enforcement action against the Connecticut Authority in the appropriate court.[3] We issue a declaratory ruling below, however, providing our views on a number of the substantive questions raised by the parties' pleadings.[4]

3. Petitioners argue that the Connecticut Authority erred by concluding that Windham is not entitled to a legally enforceable obligation at a forecasted avoided cost rate. Petitioners also disagree with the Connecticut Authority's determination that Eversource has no need for capacity.

4. The Commission's regulations expressly provide that "each" QF has the option to provide energy or capacity pursuant to a legally enforceable obligation.[5] Section 292.304(d)(1) of the Commission's regulations addresses the option to sell energy as available, while section 292.304(d)(2) of the Commission's regulations addresses the option to sell energy or capacity pursuant to a legally enforceable obligation over a specified term. Moreover, the former provides for an energy price based on avoided costs calculated at the time of delivery, while the latter provides (*at the QF's option*) for pricing based on either avoided costs calculated at the time of delivery

[1] 16 U.S.C. § 824a-3(h)(2)(B) (2012).

[2] 16 U.S.C. § 824a-3(h)(2)(A) (2012).

[3] 16 U.S.C. § 824a-3(h)(2)(B) (2012).

[4] The Administrative Procedure Act expressly provides for agencies to issue declaratory rulings, 5 U.S.C. § 554(e) (2012), and the Commission's regulations similarly provide for the Commission to issue such rulings. 18 C.F.R. § 385.207(a)(2) (2016).

[5] 18 C.F.R. § 292.304(d) (2016) ("Each qualifying facility shall have the option either: (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either: (i) The avoided costs calculated at the time of delivery; or (ii) The avoided costs calculated at the time the obligation is incurred.").

or at the time the obligation is incurred.[6] Thus, regardless of whether a QF can provide firm output, that QF has the option to sell its output pursuant to a legally enforceable obligation with a forecasted avoided cost rate.[7]

5. In its Final Decision, the Connecticut Authority concluded that Windham is only entitled to sell its output to Eversource pursuant to Rate 980, which provides an avoided cost rate that amounts to the real-time energy price for ISO-New England. The avoided cost rate provided by Rate 980 is the type of rate within the scope of section 292.304(d)(1) of the Commission's regulations. However, Windham has not opted to sell its output pursuant to section 292.304(d)(1) of the Commission's regulations. Rather, Windham has opted to sell its output pursuant to section 292.304(d)(2)(ii) of the Commission's regulations, which it is entitled to do (and at a rate based on avoided costs calculated at the time the legally enforceable obligation is incurred – which it is also entitled to do),[8] and, therefore, the Connecticut Authority must recognize that a legally enforceable obligation exists and calculate the appropriate forecasted avoided cost rate pursuant to section 292.304(d)(2)(ii) of the Commission's regulations.[9]

6. That being said, although state regulatory authorities cannot preclude a QF – even an intermittent QF – from obtaining a legally enforceable obligation with a forecasted avoided cost rate, we remind the parties that the Commission's regulations allow state

[6] *Compare* 18 C.F.R. § 292.304(d)(1) (2016) *with* 18 C.F.R. § 292.304(d)(2) (2016).

[7] *Exelon Wind 1, L.L.C. v. Nelson*, 766 F.3d 380, 400 (5th Cir. 2014), suggested that, because only "firm power" QFs can provide certainty that "promised power actually will be produced and readily available," "it makes sense that only they should be able to select between the rate options" of avoided cost at the time of delivery and avoided cost when a legally enforceable obligation is incurred. This distinction, though, is not found in the Commission's regulations, and the states, as recognized by the court, are required to implement those regulations. *See id.* at 384-85; *accord* 16 U.S.C. § 824a-3(f) (2012). Rather, section 292.304(d) expressly provides that "[*e*]*ach* qualifying facility shall have the option…[t]o provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term," and "at the option of the qualifying facility" the rate may be based on "[t]he avoided costs calculated at the time the obligation is incurred." 18 C.F.R. § 292.304(d) (2016) (emphasis added).

[8] 18 C.F.R. § 292.304(d)(2) (2016).

[9] *Allco Renewable Energy Ltd., v. Mass. Elec. Co.*, No. 15-13515-PBS, 2016 WL 5346937, at *22 (D. Mass. Sept. 23, 2016) (even in restructured state, the risk is shared; as in any contract, the purchasing utility bears the risk that prices will decrease in the future below the originally set level, and the selling QF bears the corresponding risk that prices will increase above the originally set level).

regulatory authorities to consider a number of factors in establishing an avoided cost rate.[10] These factors which include, among others, the availability of capacity, the QF's dispatchability, the QF's reliability, and the value of the QF's energy and capacity, allow state regulatory authorities to establish lower avoided cost rates for purchases from intermittent QFs than for purchases from firm QFs.

7. The Connecticut Authority also has concluded that Eversource has no need for capacity because it is located in a restructured state and its capacity needs are met by ISO-New England Inc.'s forward capacity auction. However, to the extent that Eversource's capacity needs can be satisfied by Windham's QFs rather than through the capacity auction, the avoided cost rates available to Windham should include an estimate of Eversource's avoided cost of capacity. Connecticut Authority stated in its Final Decision that Eversource can self-manage up to 20 percent of its load, which suggests that Eversource may well have capacity needs that can be met outside of the capacity auction. Moreover, independent of Eversource's ability to self-manage, Eversource's reliance on ISO-New England Inc.'s forward capacity auction does not mean that Eversource has no need for capacity, but rather its reliance on the capacity auction demonstrates only that Eversource acquires capacity through that auction, and there is no indication that Eversource would be unable to realize the appropriate value of any capacity it acquires from a QF by simultaneously offering that capacity into the auction with its bids to purchase capacity from the auction.

8. Finally, the Commission has long held that its regulations pertaining to legally enforceable obligations "are intended to reconcile the requirement that the rates for purchases equal to the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments, by necessity, on estimates of future avoided costs" and has explicitly agreed with previous commenters that "stressed the need for certainty with regard to return on investment in new technologies."[11] Given this "need for certainty with regard to return on investment," coupled with Congress' directive that

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[10] 18 C.F.R. §§ 292.304(e)-(f) (2016).

[11] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128, at 30,880, *order on reh'g sub nom.* Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part vacated in part*, *Am. Elec. Power Serv. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

the Commission "encourage" QFs,[12] a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors.[13]

By the Commission.

Kimberly D. Bose,
Secretary.

[12] 16 U.S.C. § 824a-3(a) (2012).

[13] 18 C.F.R. § 292.304(d)(2) (2016) our regulations, do not, however, specify a particular number of years for such legally enforceable obligations.

Federal Energy Regulatory Commission

JD Wind 1, LLC, 130 FERC ¶ 61,127

Feb. 19, 2010

130 FERC ¶ 61,127
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
and John R. Norris.

JD Wind 1, LLC
JD Wind 2, LLC
JD Wind 3, LLC
JD Wind 4, LLC
JD Wind 5 LLC
JD Wind 6, LLC

Docket No. EL09-77-001

ORDER DENYING "REQUESTS FOR REHEARING, RECONSIDERATION OR CLARIFICATION"

(Issued February 19, 2010)

1. On November 19, 2009, the Commission issued an order responding to a petition for enforcement under section 210(h) of the Public Utilities Regulatory Policies Act of 1978 (PURPA) filed by JD Wind 1, LLC, JD Wind 2, LLC, JD Wind 3, LLC, JD Wind 4, LLC, JD Wind 5, LLC, and JD Wind 6, LLC (collectively, JD Wind).[1] In the November 19 Order, the Commission gave notice that it declined to initiate an enforcement action pursuant to the section 210(h) of the Public Utility Regulatory Policies Act of 1978 (PURPA).[2] In the November 19 Order, in response to JD Wind's petition for declaratory order, the Commission also declared that the May 1, 2009 decision of the Public Utility Commission of Texas (Texas Commission)[3] -- which determined that JD Wind's wind-powered generation is not entitled to a legally enforceable obligation and an avoided cost

[1] *JD Wind 1, LLC*, 129 FERC ¶ 61,148 (2009) (November 19 Order).

[2] 16 U.S.C. § 824a-3(h) (2006).

[3] *JD Wind I, LLC v. Southwestern Public Service Co.*, Texas Commission Docket No. 3442 (May 1, 2009) (Texas Commission Order).

rate calculated at the time that obligation is incurred -- is inconsistent with the requirements of PURPA and our regulations implementing PURPA.[4]

2. Occidental Permian Ltd. (Occidental) and Xcel Energy Services, Inc. (Xcel) each filed pleadings styled as requests for rehearing, reconsideration, or clarification of the November 19 Order. Occidental and Xcel claim that the November 19 Order erred by declaring that the Texas Commission Order was inconsistent with PURPA and the Commission's regulations implementing PURPA. As discussed below, Occidental and Xcel have raised nothing in their requests that warrants changing our decision in the November 19 Order; we accordingly deny the requests.

Background

3. As discussed more fully in the November 19 Order, JD Wind 1, LLC, JD Wind 2, LLC, JD Wind 3, LLC, JD Wind 4, LLC, JD Wind 5, LLC, and JD Wind 6, LLC are each a wholly-owned subsidiary of John Deere Renewables, LLC; each of the companies that comprise JD Wind owns and operates small power production facilities that have been self-certified as qualifying facilities (QF). JD Wind sought to enter into contracts with Southwestern Public Service Company (SPS) to sell the electric energy output from its QFs pursuant to long-term contracts at avoided cost rates. When negotiations failed, JD Wind sought to establish legally enforceable obligations pursuant to the procedures of the Texas Commission. On June 27, 2007, JD Wind filed a complaint with the Texas Commission seeking a legally enforceable obligation from SPS and seeking rates based on the avoided costs calculated at the time that obligation was incurred. JD Wind pointed to section 292.304(d) of the Commission's regulations,[5] which gives QFs the option of selling energy "as available"[6] or selling "energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term."[7] If a QF chooses the second option, i.e., to sell energy or capacity over a specified term pursuant to a legally enforceable obligation, it has the option to sell at rates either based on avoided costs calculated at the time of delivery,[8] or based on avoided costs calculated at the time the obligation is incurred.[9] In the complaint before the Texas Commission,

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[4] 16 U.S.C. § 824a-3 (2006); 18 C.F.R. Part 292 (2009).

[5] 18 C.F.R. § 292.304(d) (2009).

[6] *Id.* § 292.304(d)(1).

[7] *Id.* § 292.304(d)(2).

[8] *Id.* § 292.304(d)(2)(i).

[9] *Id.* § 292.304(d)(2)(ii).

JD Wind sought both a legally enforceable obligation, and rates based on avoided costs calculated at the time the obligation was incurred.

4. A Texas Commission Administrative Law Judge issued a Proposal for Decision on March 25, 2009. As relevant here, the Administrative Law Judge found that, under Texas law, a legally enforceable obligation requires a showing that the QF is capable of providing “firm power,” and that, in the absence of that showing, “the JD Wind Companies cannot create a legally enforceable obligation.”[10] The Administrative Law Judge’s decision was largely based on a finding of fact that “Wind-Generated Power is not readily available.”[11] The Texas Commission affirmed the Administrative Law Judge’s decision with the exception of the latter finding that “Wind-Generated Power is not readily available.” The Texas Commission concluded that the Administrative Law Judge’s decision otherwise supported a finding that JD Wind did not offer “firm power,” and the Texas Commission affirmed and adopted the Administrative Law Judge’s decision.[12]

5. JD Wind then came to this Commission, petitioning the Commission to enforce the requirements of our regulations, and to issue a declaratory order as to the meaning of the Commission’s regulations. The November 19 Order resulted.

November 19 Order

6. The Commission exercised its discretion and declined to go to court to enforce PURPA on JD Wind’s behalf. The Commission, however, declared that JD Wind has the right to a legally enforceable obligation. The Commission pointed out that its regulations implementing PURPA include an express requirement that *each* QF has the option to sell not only on an “as available” basis, but also has the option to sell pursuant to legally enforceable obligations over specified terms.[13] The Commission specifically pointed to section 292.304(d),[14] which provides:

> (d) *Purchases “as available” or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

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[10] *JD Wind I, LLC, et al. v. Southwestern Public Service Co.*, Texas Commission Docket No. 3442 at 32-38 (March 25, 2009).

[11] *Id.* at 40.

[12] Texas Commission Order at 1.

[13] November 19 Order, 129 FERC ¶ 61,148 at P 25-29.

[14] *Id.*; 18 C.F.R. § 292.304(d) (2009).

> (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided costs calculated at the time of delivery; or
>
> (ii) The avoided costs calculated at the time the obligation is incurred.

7. Noting that section 292.304(d) and its requirement that a QF can sell and a utility must purchase pursuant to a legally enforceable obligation were specifically adopted to prevent utilities from circumventing the requirement of PURPA that utilities purchase energy and capacity from QFs, the Commission concluded that, under the language of its regulations, a QF has the option to commit itself to sell all or part of its electric output to an electric utility through a contract or a non-contractual, but still legally enforceable, obligation.[15] The Commission concluded that a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF. The Commission explained that these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.[16]

8. The Commission concluded that the Texas Commission Order, denying JD Wind's request to establish a legally enforceable obligation and finding that the award of a legally enforceable obligation is limited to only those QFs that provide "firm" power, is inconsistent with the Commission's regulations implementing PURPA.[17] Under these regulations, each QF, including each QF owned by JD Wind, has the right to choose to

[15] November 19 Order, 129 FERC ¶ 61,148 at P 25, 29; *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, FERC Stats. & Regs. ¶ 31,233, at P 212 (2006), *order on reh'g*, Order No. 688-A, FERC Stats. & Regs. ¶ 31,250, at P 136-37 (2007), *aff'd sub nom. American Forest and Paper Association v. FERC,* 550 F.3d 1179 (D.C. Cir. 2008); *see also Midwest Renewable Energy Projects, LLC,* 116 FERC ¶ 61,017 (2006).

[16] November 19 Order, 129 FERC ¶ 61,148 at P 25, 29.

[17] *Id.* P 26-29.

sell pursuant to a legally enforceable obligation, and, in turn, has the right to choose to have rates calculated at avoided costs calculated at the time that obligation is incurred.[18]

Requests for Rehearing, Reconsideration or Clarification

9. In its request, Xcel argues that the Commission has reinterpreted section 292.304 of the Commission's regulations in a manner that is inconsistent with PURPA and Congressional intent. Xcel also argues that this allegedly new interpretation of the regulations will result in rates that exceed avoided costs, in violation of PURPA.[19] Finally Xcel argues that the Commission should have instituted a rulemaking before re-interpreting its regulations. Xcel also asks the Commission to clarify that its November 19 Order is "of no legal moment." Xcel further asks the Commission to clarify that its order is not binding on the Texas Commission.

10. In its request, Occidental argues that the Commission's November 19 Order relies on what Occidental characterizes as a newly-announced interpretation of section 292.304(d) of its regulations that, Occidental argues, misconstrues the language of that provision and is contrary to PURPA. Occidental also argues that the decision of whether a legally enforceable obligation has been established is the responsibility of the state regulatory authority, and not the Commission. Occidental also argues that the November 19 Order is inconsistent with PURPA's requirement that payments to QFs may not exceed a utility's avoided costs; Occidental argues that the November 19 Order assumes that utilities must treat "as available" resources as though they are firm for purposes of calculating avoided costs. Finally, Occidental argues that the Commission can not extend legally enforceable pricing options to intermittent, non-firm QF power, in the context of a declaratory order; Occidental argues that, to extend the right of establishing legally enforceable obligations to intermittent resources, the Commission should have acted in the context of a rulemaking. Occidental also asks the Commission to clarify that the Commission: (1) made no findings about whether JD Wind satisfied Texas procedural requirements for establishing a legally enforceable obligation; and (2) did not address the appropriate avoided cost rate that JD Wind should be paid.

11. JD Wind filed a response to the requests of Occidental and Xcel asking the Commission to summarily dismiss the requests on the ground that rehearing does not lie.

[18] *Id.*

[19] Xcel also argues that the Commission has engaged in a rulemaking in this proceeding, rather than in a declaration of the meaning of an existing rule, and that rehearing of the November 19 Order lies under the Federal Power Act.

Discussion

Procedural Matters

12. Because this proceeding arises under section 210(h) of PURPA, formal rehearing does not lie, either on a mandatory or a discretionary basis.[20] We will, however, address the requests, as provided below.

13. The Commission's Rules of Practice and Procedure, although silent with respect to requests for reconsideration and answers to requests for reconsideration, do not normally permit answers to requests for rehearing.[21] We have previously indicated that the concerns that militate against answers to requests for rehearing similarly should apply to answers to requests for reconsideration.[22] Accordingly, we will reject JD Wind's answer.

Commission Determination

14. We deny Occidental and Xcel's requests. Nothing raised in the requests warrants a change to our November 19 Order.

15. Both Occidental and Xcel argue that the Commission's November 19 Order represents a change to its interpretation of section 292.304(d) of its regulations.[23] Both also argue, relying primarily on a portion of the legislative history of PURPA,[24] that the alleged change to the interpretation contained in the November 19 Order is inconsistent with PURPA. We disagree.

16. As an initial matter, we do not believe that our interpretation of section 292.304(d) of our regulations represents a change. As pointed out in the November 19 Order, our decision was based primarily on the express language of section 292.304(d) of our regulations, which gives "*each*" QF the option to choose to sell on what is known as an "as available" basis (section 292.304(d)(1)), or to sell pursuant to a legally enforceable

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[20] *See Southern California Edison Co.*, 71 FERC ¶ 61,090, at 61,305 (1995); *New York State Electric & Gas Corp.*, 72 FERC ¶ 61,067, at 61,340 (1995).

[21] 18 C.F.R. § 385.713(d) (2009).

[22] *See CGE Fulton, L.L.C.*, 71 FERC ¶ 61,232, at 61,880-81 (1995); *Connecticut Light & Power Co.*, 71 FERC ¶ 61,035, at 61,151 (1995).

[23] 18 C.F.R. § 292.304(d) (2009).

[24] H.R. Rep. No. 95-1750, at 99 (1978).

obligation (section 292.304(d)(2)).[25] If the QF chooses to sell pursuant to a legally enforceable obligation, it has the express right to choose a rate based on either the avoided costs calculated at the time of delivery,[26] or the avoided costs calculated at the time the obligation is incurred.[27] Because the Commission relied on the express language of the regulation, the November 19 Order in no way represents a breaking of new ground, or in any sense a change of policy. Occidental and Xcel, moreover, do not point to Commission precedent that interpreted section 292.304(d) differently.[28]

17. Any suggestion that the preamble to the Commission's order adopting its original regulations could be read to prohibit the award of a legally enforceable obligation to a nonfirm resource must equally fail. The Commission, in its November 19 Order, pointed out that doing so reads the language concerning firmness out of context; that language, in fact, provides no reasonable basis for an understanding that legally enforceable obligations are limited to firm resources.[29] The preamble to its adoption of the regulation at issue here expressly contemplated that QFs could receive a capacity payment.[30] And, in fact, the Commission recognized the possibility that intermittent QF resources, including solar and wind resources, which would not be considered "firm" using traditional utility concepts, could still enable a utility to avoid capacity, and that "the aggregate capacity value of such facilities must be considered in the calculation of rates

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[25] 18 C.F.R. § 292.304(d) (2009) (emphasis added). The difference between these options is: when a QF chooses to sell pursuant to a legally enforceable obligation, it commits ahead of time to sell all or some part (e.g., during certain hours) of its output to an electric utility; when a QF chooses instead to sell on an "as available" basis, it makes no such advance commitment to the electric utility and may choose to make sales to the electric utility essentially at its discretion.

[26] 18 C.F.R. § 292.304(d)(2)(i) (2009).

[27] 18 C.F.R. § 292.304(d)(2)(ii) (2009).

[28] The fact that Texas may have implemented section 292.304(d) of our regulations inconsistently with the express language of the regulation is not evidence as to the proper interpretation of the regulation. Nor is the fact that the inconsistent implementation may have been long standing. We do not routinely review the states' implementation of PURPA for consistency with our regulations; review typically occurs, as here, when we are presented with a petition for enforcement.

[29] November 19 Order, 129 FERC ¶ 61,148 at P 28.

[30] *Id.*

for purchases."[31] As capacity payments are available under section 292.304(d) only to those facilities that have chosen the legally enforceable obligation, even aside from the express language of the regulation, the preamble to the order adopting the regulation supports a finding that the Commission always intended that nonfirm, intermittent QF resources are included in the phrase "each qualifying facility" that has the option to choose to sell pursuant to a legally enforceable obligation.

18. In sum, our interpretation of section 292.302(d) is based on the express language of the regulation, and is also consistent with the preamble to the regulation issued at the time the regulation was enacted. We, accordingly, conclude that our interpretation of section 292.302(d) of our regulations is in no way a new interpretation of the regulation.

19. Occidental and Xcel's remaining arguments largely depend on the argument that the Commission in the November 19 Order has reinterpreted section 292.304(d) of its regulations. In this regard, Occidental and Xcel claim that the Commission should have announced this interpretation of section 292.304(d) in the context of a rulemaking because the interpretation constitutes a change to the regulation which, they claim, can be accomplished only by a rulemaking. Because our interpretation of section 292.304(d) does not represent a change, however, Occidental and Xcel's argument that the Commission should have instituted a rulemaking must fail.

20. Similarly, Xcel's argument that the Commission should look to PURPA's legislative history to limit section 292.304(d) is misplaced. Section 292.304(d) constitutes part of the Commission's original implementation of PURPA in 1980, which was appealed to the Supreme Court, and was affirmed.[32] Xcel's arguments about the legislative history are, in effect, a very belated collateral attack on the original rulemaking; to the extent that a party wished to raise the issue of the consistency of our regulations with PURPA, including the issue of the consistency of our regulation granting a QF the option of selling pursuant to a legally enforceable obligation with PURPA, the issue should have been raised in the context of that rulemaking and the appeal of that rulemaking.

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[31] *Id.* P 28 & n.42. (*citing* Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,882.)

[32] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978,* Order No. 69, FERC Stats. & Regs. ¶ 30,128 (1980), *order on reh'g,* Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part and vacated in part*, *American Electric Power Service Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part*, *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 461 U.S. 402 (1983).

21. Nonetheless, we will address the argument here and we find that the legislative history cited by Xcel does not support a finding that section 292.304(d) is inconsistent with PURPA. Xcel points to the following language to support its argument that Congress intended that nonfirm power cannot qualify for a legally enforceable obligation:

> The conferees expect that the Commission, in judging whether the electric power supplied by the [qualifying facility] will replace future power which the utility would otherwise have to generate itself either through existing capacity or additions to capacity or purchase from other sources, will take into account the reliability of the power supplied by the [qualifying facility] by reason of any legally enforcible [sic] obligation of such [qualifying facility] to supply firm power to the utility.[[33]]

This language, however, does not address the issue of whether a QF has the option of selling nonfirm power pursuant to legally enforceable obligation. Rather this language reflects the Congressional conferees' concern that the firmness of power be considered in determining the rate for that power – particularly the capacity component of the rate.[34] The Commission's regulations, discussed above, addressing both the right to a legally enforceable obligation as well as, separately, consideration of the firmness of the power in developing the rate for that power, are consistent with this concern.

22. We next turn to Occidental and Xcel's arguments that our interpretation of section 292.304(d) will result in rates for intermittent QF resources that exceed the utility's avoided costs. As an initial matter, we note that Occidental is correct that the Texas Commission, because it ruled that the JD Wind facilities were not entitled to a legally enforceable obligation, never calculated a rate based on the utility's avoided cost calculated at the time the obligation was incurred. Nor did JD Wind's petition ask us to address the issue of how to calculate avoided costs, other than asking the Commission to declare that JD Wind was entitled to rates based on avoided costs calculated at the time the legally enforceable obligation was incurred. Consequently, this Commission has not in this proceeding addressed the calculation of an avoided cost rate for the JD Wind facilities. The Commission, in the November 19 Order, ruled only that the JD Wind facilities are entitled to a legally enforceable obligation, and thus, under section 292.304(d)(2), to an avoided cost rate calculated at the time the obligation is incurred; the Commission did not address any proposed calculation of avoided costs. Occidental and

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[33] H.R. Rep. No. 95-1750, at 99 (1978).

[34] November 19 Order, 129 FERC ¶ 61,148 at P 28; *see* Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,881-83. The Commission has, in fact, indicated that firm capacity can be provided by dispersed wind systems. *Id.* at 30,882.

Xcel nonetheless suggest that an avoided cost rate cannot be accurately calculated for intermittent resources at the time the obligation is incurred.

23. The Commission's regulations, from the beginning, have given QFs the option of choosing to have rates calculated at the time the obligation is incurred. The intention of the Commission was to enable a QF "to establish a fixed contract price for its energy and capacity at the outset of its obligation."[35] The Commission recognized that:

> [I]n order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.[[36]]

The Commission recognized that avoided costs could change over time, and that the avoided costs and rates determined at the time a legally enforceable obligation was incurred could differ from the avoided costs at the time of delivery.[37] The Commission has, since then, consistently affirmed the right of QFs to long-term avoided cost contracts or other legally enforceable obligations with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred.[38] Rates based on avoided costs at the time the obligation is originally incurred are consistent with the requirements of PURPA, and we see no impediment to accurately determining such rates for QFs powered by intermittent resources.

24. Occidental argues that the Commission should not have commented on this case on the ground that the Commission's longtime practice has been to leave to state commissions the issue of when a legally enforceable obligation is created. Occidental is correct that the Commission generally does leave to state commissions the issue of when and how a legally enforceable obligation is created.[39] However, that the Commission

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[35] *Id.* at 30,880.

[36] *Id.* at 30,868.

[37] *Id.* at 30,880.

[38] *See, e.g., New York State Electric & Gas Corp.*, 71 FERC ¶ 61,027, at 61,115-16 (1995), *order denying reconsideration*, 72 FERC ¶ 61,067 (1995), *appeal dismissed sub nom. New York State Electric & Gas Corp. v. FERC*, 117 F.3d 1473 (D.C. Cir. 1997).

[39] Occidental is also correct that the Commission has twice refused to prematurely address certain issues between Xcel and JD Wind. *See Xcel Energy Services, Inc.*, 122 FERC ¶ 61,048, at P 45 (2008) (the Commission, because it was denying Xcel's PURPA (continued…)

generally leaves this issue to the states (and to nonregulated utilities when applicable), does not mean that a state commission is free to ignore the requirements of PURPA or the Commission's regulations. Under PURPA, the Commission has prescribed "such rules as it determines necessary to encourage cogeneration and small power production." [40] PURPA, in turn, directs the states to "implement" the rules adopted by the Commission.[41] When a state commission ignores the requirements of PURPA, as implemented in our regulations, the QF has the right under PURPA to seek enforcement of its PURPA rights.[42] The first step in the enforcement process is the QF's filing of a petition pursuant to section 210(h)(2)(B) of PURPA.[43] Section 210(h)(2)(B) of PURPA permits any qualifying small power producer, among others, to petition the Commission to act under section 210(h)(2)(A) of PURPA[44] to enforce the requirement that a state commission implement the Commission's regulations. JD Wind filed such a petition, and, in response, in the November 19 Order, the Commission declined to go to court on JD Wind's behalf. When the Commission declines to go to court, it can do so with or without making a statement as to its position on the issues. Here, the Commission chose

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section 210(m) petition to terminate the mandatory purchase obligation, declined to address whether a legally enforceable obligation had been established); *Xcel Energy Services, Inc. v. Southwest Power Pool, Inc.*, 118 FERC ¶ 61,232, at P 27 (2007) (the dispute between Xcel and JD Wind concerning the particular rate for, and the terms and conditions governing, a sale were a matter to be resolved pursuant to Texas' implementation of PURPA). In each of these cases, the Commission left certain PURPA implementation issues to the Texas Commission. Our decisions in those two cases, however, did not authorize the Texas Commission to resolve issues in a manner inconsistent with our regulations. The Texas Commission having done so, however, it is now appropriate for the Commission to give guidance on the meaning of our regulations.

[40] 16 U.S.C. §§ 824a-3(a)-(b) (2006).

[41] 16 U.S.C. § 824a-3(f) (2006); *accord FERC v. Mississippi*, 456 U.S. 742, 751 (1982); *Independent Energy Producers Association v. California Public Utilities Commission*, 36 F.3d 848, 856 (9th Cir. 1994); *Cogeneration Coalition of America, Inc.*, 61 FERC ¶ 61,252, at 61,925-26 (1992).

[42] November 19 Order, 129 FERC ¶ 61,148 at P 21.

[43] 16 U.S.C. § 824a-3(h)(2)(B) (2006).

[44] 16 U.S.C. § 824a-3(h)(2)(A) (2006).

to provide a statement of its position on the issues. We have done so before, and there was nothing unusual or inappropriate in our doing so here.[45]

25. Where, as here, the Commission does not undertake an enforcement action within 60 days of the filing of a petition, under section 210(h)(2)(A) of PURPA the petitioner then may bring its own enforcement action directly against the state regulatory authority or nonregulated electric utility in the appropriate United States district court.[46] Our November 19 Order, as well as the instant order, serve as a statement of our position regarding the right under PURPA of each QF to enter into a legally enforceable obligation.[47]

<u>The Commission orders</u>:

Occidental's and Xcel's requests are hereby denied.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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[45] *See, e.g., MidAmerican Energy Co.*, 85 FERC ¶ 61,470 (1998) (Notice of Intent Not to Act, stating that the Commission would issue a later declaratory order), *and*, 94 FERC ¶ 61,340 (2001) (later declaratory order where the Commission found that Iowa's net metering law does not conflict with PURPA); *Connecticut Light & Power Co.*, 70 FERC ¶ 61,012 (1995), *reconsideration denied*, 71 FERC ¶ 61,012 (state adder to avoided cost rate conflicts with PURPA).

[46] 16 U.S.C. § 824a-3(h)(2)(B) (2006). The Commission may intervene in such a district court proceeding as a matter of right. *Id.*

[47] *Cf.* 18 C.F.R. § 385.207(a)(2) (2009) (providing for petitions for declaratory orders or rulings to terminate controversy or remove uncertainty). To the extent that Xcel has argued that a declaratory order has no legal effect and is of no legal moment, we note that Xcel itself has on at least one recent occasion sought a declaratory order from the Commission. *See, e.g., Tri-County Electric Cooperative, Inc., Xcel Energy Services, Inc., and Southwestern Public Service Co.,* 117 FERC ¶ 61,280, at P 1 (2006).