BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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

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

[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

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[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

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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

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

[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 <u>87.5%</u> 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

[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.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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

Community Renewable Energy Association

Exhibit 101

Summary of CREA's Response to Issues List

March 18, 2013

Summary of CREA's Position

Issue 1. Avoided Cost Price Calculation

Issue 1. A. What is the most appropriate methodology for calculating avoided cost prices?

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

CREA's Response: Retain the current method for standard rates based upon the next avoidable resource in the IRP. CREA opposes Idaho Power's proposed changes for standard and non-standard rates. CREA/200, Reading/2-9.

ii. Should the methodology be the same for all three electric utilities operating in Oregon?

CREA's Response: Yes. Alternatively, if Idaho Power is permitted to have a different method for consistency with Idaho rules, Idaho Power's proposals should not apply to PGE and PacifiCorp. CREA/200, Reading/2-9.

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

CREA's Response: Yes. CREA/200, Reading/9-12.

Issue 1. C. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different than the market price?

CREA's Response: Yes. CREA/200, Reading/13.

Issue 1. D. Should the Commission eliminate unused pricing options?

CREA's Response: CREA supports removal of the rate schedules for the gas market indexed and banded gas market indexed options, so long as these options are available by request to interested QFs. CREA/200, Reading/13-14.

Issue 2. Renewable Avoided Cost Price Calculation

Issue 2. A. Should there be different avoided cost prices for different renewable generation sources? (for example different avoided cost prices for intermittent vs. base load renewables; different avoided cost prices for different technologies, such as solar, wind, geothermal, hydro, and biomass.)

CREA's Response: The renewable avoided cost rates should be adjusted upwards during the deficiency period to compensate those renewable QFs who allow the utility to partially or fully avoid the costs of integrating renewable power from the avoided renewable plant – a large utility wind plant. CREA/300, Svendsen/3-7.

Issue 2. B. How should environmental attributes be defined for purposes of PURPA transactions?

CREA's Response: The definition should specify that the renewable QF conveys RECs necessary for compliance with Oregon's renewable portfolio standard, but retains any remaining environmental attributes such as greenhouse gas offsets. Non-renewable QFs retain all environmental attributes. CREA/300, Svendsen/7-11.

Issue 2. C. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?

CREA's Response: No. Renewable QF contracts can require the renewable QF to convey RECs to the utility. QFs choosing to sell at the non-renewable rates should continue to retain all environmental attributes. CREA/300, Svendsen/11-12.

<u>Issue 3. Schedule for Avoided Cost Price Updates</u>

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?

CREA's Response: No specific recommendation. CREA will respond to proposals by other parties. CREA/100, Hilderbrand/7-11.

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

CREA's Response: If there will be mid-cycle updates, CREA is in favor of transparent criteria. CREA/100, Hilderbrand/7-11.

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.)

CREA's Response: If there will be mid-cycle updates, CREA is in favor of defining which items will be updated. CREA/100, Hilderbrand/7-11.

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?

CREA's Response: No specific recommendation. CREA will respond to proposals by other parties. CREA/100, Hilderbrand/7-11.

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?

CREA's Response: No specific recommendation. CREA will respond to proposals by other parties. CREA/100, Hilderbrand/7-11.

<u>4. Price Adjustments for Specific QF Characteristics</u>

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

CREA's Response: Small QFs (under 10 MW) should not have avoided cost rates reduced for integration. Alternatively, if the Commission implements an integration charge for small QFs, a wind integration charge should not apply to solar QFs, and it should be reduced for small wind QFs. Any integration charge should also be reduced for partially or fully integrated deliveries. CREA/200, Reading/14-17; CREA/300, Svendsen/12.

Issue 4. B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?

CREA's Response: For PGE and PacifiCorp, the avoided cost rate calculation should include an avoided transmission cost adder. CREA/200, Reading/17-20; CREA/300, Svendsen/12-15.

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

CREA's Response: For standard rates, the Commission should apply the seven factors in the aggregate and should include reasonable adders for all components of the applicable avoided resource and deferral of "lumpy" utility investments. CREA/200, Reading/20-28; CREA/300, Svendsen/15-18.

<u>Issue 5. Eligibility Issues</u>

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

CREA's Response: No. CREA/100, Hilderbrand/11-13; CREA/200, Reading/28-30.

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?*

CREA's Response: CREA supports the current five-mile separation rule, and opposes elimination of the passive investor exception. However, CREA will respond to any reasonable revisions proposed by other parties. CREA/100, Hilderbrand/13-16; CREA/200, Reading/31.

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"?

CREA's Response: No. CREA/100, Hilderbrand/16; CREA/200, Reading/31.

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

CREA's Response: Yes. A renewable QF can dispose of the RECs as it chooses during the sufficiency period. CREA/100, Hilderbrand/17.

Issue 6. Contracting Issues

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

CREA's Response: CREA will address legal issues in briefing. CREA opposes a rule requiring a QF to be online within one year of forming a legally enforceable obligation. CREA recommends allowing QFs to lock in rates by requesting that a utility file a disputed contract unexecuted with the Commission. CREA/100, Hilderbrand/17-20; CREA/200, Reading/31-35.

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

CREA's Response: PacifiCorp's proposed MAG should apply to all three utilities. CREA/100, Hilderbrand/20-29.

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

CREA's Response: CREA opposes reduction of the fixed-rate term to less than 15 years. CREA supports a fixed-rate term of 20 years or longer. CREA/100, Hilderbrand/30; CREA/200, Reading/35.

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 102

PGE's Standard Contract MAG Provisions

March 18, 2013

STANDARD CONTRACT OFF SYSTEM POWER PURCHASE AGREEMENT FOR INTERMITTENT RESOURCES

THIS AGREEMENT, entered into this 29th day, April 2010, is between PáTu Wind Farm, LLC ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties").

RECITALS

Seller intends to construct, own, operate and maintain a small wind facility for the generation of electric power located in Sherman County, Oregon with a Nameplate Capacity Rating of 9,000 kilowatt ("kW"), as further described in Exhibit B ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.18, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1. "As-built Supplement" means the supplement to Exhibit B provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.

1.2. "Base Hours" is defined as the total number of hours per Contract Year (8,760 or 8,784 for leap year).

1.3. "Billing Period" means from the start of the first day of each calendar month to the end of the last day of each calendar month.

1.4. "Capacity Value" has the meaning provided for in the Tariff (as defined below).

1.5. "Cash Escrow" means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.

1.6. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable which shall require, among other things, that all of the following events have occurred:

1.6.1. PGE has received a certificate addressed to PGE from a Licensed Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.6 can be provided by one or more LPEs);

1.6.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.27;

1.6.3. After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement uninterrupted for a Test Period at a rate in kW of at least 75 percent of average annual Net Output divided by 8,760 based upon any sixty (60) minute period for the entire testing period. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the operation of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;

1.6.4. PGE has received a certificate addressed to PGE from an LPE stating that all required interconnection facilities have been constructed, and all required interconnection tests have been completed;

1.6.5. PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;

1.6.6. PGE has received a copy of the Transmission Agreement.

1.7. "Contract Price" means the applicable price as selected by Seller in Section 5.

1.8. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date falling at least partially in the Term of this Agreement.

1.9. "Effective Date" has the meaning set forth in Section 2.1.

1.10. "Environmental Attributes" means any and all current or future credits, benefits, emissions reductions, environmental air quality credits, emissions reduction credits, offsets and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance attributable to the Facility during the Term, or otherwise attributable to the generation, purchase, sale or use of energy from or by the Facility during the Term, including without limitation any of the same arising out of legislation or regulation concerned with oxides of nitrogen, sulfur or carbon, with particulate matter, soot or mercury, or implementing the United Nations Framework Convention on Climate Change (the "UNFCCC") or the Kyoto Protocol to the UNFCCC or crediting "early action" emissions reduction, or laws or regulations involving or administered by the Clean Air Markets Division of the Environmental Protection Agency or successor administrator, or any State or federal entity given jurisdiction over a program involving transferability of Environmental Attributes, and any Green Tag Reporting Rights to such Environmental Attributes.

1.11. "Facility" has the meaning set forth in the Recitals.

1.12. "Generation Interconnection Agreement" means an agreement governing the interconnection of the Facility with Wasco Electric Cooperative electric system.

1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.

1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.

1.15. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

$$MAP = 100 \times (\text{Operational Hours}) / (\text{Base Hours})$$

1.16. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.

1.17. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.

1.18. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses. Net Output does not include any environmental attributes.

1.19. "Off-Peak Hours" has the meaning provided in the Tariff.

1.20. "On-Peak Hours" has the meaning provided in the Tariff.

1.21. Operational Hours" for the Facility means the number of hours the Facility is potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather conditions, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery. Hours during which an event of Force Majeure exists that prevents the Facility from producing or delivering power shall be considered Operational Hours.

1.22. "Point of Receipt" means the PGE System.

1.23. "Prime Rate" means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.

1.24. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.

1.25. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.

1.26. "Senior lien" means a prior lien which has precedence as to the property under the lien over another lien or encumbrance.

1.27. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.

1.28. "Step-in rights" means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.

1.29. "Tariff" shall mean PGE rate Schedule 201 filed with the Oregon Public Utilities Commission ("Commission") in effect on the Effective Date of this Agreement and attached hereto as Exhibit D.

1.30. "Term" shall mean the period beginning on the Effective Date and ending on the Termination Date.

1.31. "Test Period" shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.

1.32. "Transmission Agreement" means an Agreement executed by the Seller and the Transmission Provider(s) for Transmission Services.

1.33. "Transmission Curtailment" means a limitation on Seller's ability to deliver any portion of the scheduled energy to PGE due to the unavailability of transmission to the Point of Receipt (for any reason other than Force Majeure)

1.34. "Transmission Curtailment Replacement Energy Cost" means the greater of zero or the amount calculated as: ((Dow Jones Mid C Index Price – Contract Price) X curtailed energy) for periods of Transmission Curtailment.

1.35. "Transmission Provider(s)" means the signatory (other than the Seller) to the Transmission Agreement.

1.36. "Transmission Services" means any and all services (including but not limited to ancillary services and control area services) required for the firm transmission and delivery of Energy from the Facility to the Point of Receipt for a term not less than the Term of this Contract.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1 This Agreement shall become effective upon execution by both Parties ("Effective Date").

2.2 Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore, liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

3.1.6 Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.

3.1.7 Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.

3.1.8 Seller warrants that Net Dependable Capacity of the Facility is 8,800 kW.

3.1.9 Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is 26,000,000 kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.

3.1.10 Seller represents and warrants that the facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):

3.1.10.1 Ninety-one percent (91%) for the first Contract Year; and

3.1.10.2 Ninety-five percent (95%) beginning Contract Year two and extending throughout the remainder of the Term.

3.1.10.3 Annually, by March 1st, Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.

3.1.11 Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of 45,000,000 kWh of Net Output during each Contract Year ("Maximum Net Output"). The cost of delivering energy from the Facility to PGE is the sole responsibility of the Seller.

3.1.12 Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.

3.1.13 PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.

3.1.14 Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Rates and Standard Contract in PGE's Tariff. Seller will provide, upon request by Buyer not more frequently

SECTION 7: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 8: BILLINGS, COMPUTATIONS AND PAYMENTS

8.1 On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement and any other agreement related to the Facility between the Parties or otherwise.

8.2 Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 9: DEFAULT, REMEDIES AND TERMINATION

9.1 In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:

9.1.1 Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.

9.1.2 Seller's failure to provide default security, if required by Section 7, prior to delivery of any Net Output to PGE or within 10 days of notice.

9.1.3 Seller's failure to meet the MAP established in Section 3.1.10 – Guarantee of Mechanical Availability for any single Contract Year or Seller's failure to provide any written report required by that section.

9.1.4 If Seller is no longer a Qualifying Facility.

9.1.5 Failure of PGE to make any required payment pursuant to Section 8.1.

9.2 In the event of a default hereunder, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party, and, except for damages related to a default pursuant to Section 9.1.3 by a QF sized at 100 kW or smaller, may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. Such termination shall be effective upon the date of delivery of notice, as provided in Section 21. The rights provided in this Section 9 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.

9.3 If this Agreement is terminated as provided in this Section 9, PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.

9.4 In the event PGE terminates this Agreement pursuant to this Section 9, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.

9.5 Sections 9.1, 9.3, 9.4, 11, and 20.2 shall survive termination of this Agreement.

SECTION 10: TRANSMISSION CURTAILMENTS

10.1 Seller shall give PGE notice as soon as reasonably practicable of any Transmission Curtailment that is likely to affect Seller's ability to deliver any portion of energy scheduled pursuant to Sections 4.4 of this Agreement.

10.2 If as the result of a Transmission Curtailment, Seller does not deliver any portion of energy (including real-time adjustments), scheduled pursuant to Section 4.4 of this Agreement, Seller shall pay PGE the Transmission Curtailment Replacement Energy Cost for the number of MWh of energy reasonably determined by PGE as the difference between (i) the scheduled energy that would have been delivered to PGE under this Agreement during the period of Transmission Curtailment and (ii) the actual energy, if any, that was delivered to PGE for the period.

insurance required hereunder; a cross-liability or severability of insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be $1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

12.2 Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.

12.3 Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 13: FORCE MAJEURE

13.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

13.2 If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

13.2.1 the non-performing Party, shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

13.2.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and

13.2.3 the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.

13.3 No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.

13.4 Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 14: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 15: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 16: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally

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

REDACTED Exhibit 103

MAG Comments Provided to Mr. Hilderbrand

March 18, 2013

Ormand Hilderbrand

Subject: FW: PáTu MAG Issues

From: Dave Luck [mailto:Dave.Luck@enXco.com]
Sent: Thursday, February 09, 2012 9:04 AM
To: Ormand Hilderbrand
Cc: Todd Brogna; John Durels
Subject: RE: PáTu MAG Issues

Ormand,

Reviewing the "MAG" language you provided (below), I note several things that stand out from the Availability Warranties typically offered by turbine manufacturers and 3rd party O&M providers:

- There is no specified remedy for failure to meet the specified target availability. Most Availability Warranties I am familiar with have specified Liquidated Damages based on how much the actual availability is below the warranted level – and many of these clauses have bonus provisions for exceeding the warranted availability: Both have specified caps. There are a few contracts I am aware of that provide for termination of the Service Agreement if the availability level is persistently very low.
- The language you provided lacks the typical "carve outs" from the availability calculation. While there is a variety of language used, and some specifics are a product of negotiation, the attached is a sample of an availability calculation.
- 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 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.

You asked about my experience in the industry. I have been in the energy industry for over 35 years, and involved in wind since 1992 (first as an owner). To be clear, the above represents my observations of the situation, and not an official position of enXco Service Corporation.

Let me know if you need anything else.

Regards,
Dave L

Dave Luck
Director of Business Development
enXco Service Corp
503-913-6212
Dave.luck@enxco.com

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 104

MAG Provisions of PacifiCorp's Standard Contract

March 18, 2013

POWER PURCHASE AGREEMENT

BETWEEN

____

[a new Firm Qualifying Facility with 10,000 kW Facility Capacity Rating, or Less and an Intermittent Resource with Mechanical Availability Guarantee]

AND

PACIFICORP

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT, entered into this ____day of ______________, 20____, is between _________________________, "**Seller**" and PacifiCorp (d/b/a Pacific Power & Light Company), an Oregon corporation acting in its regulated utility capacity, "**PacifiCorp**." (Seller and PacifiCorp are referred to individually as a "**Party**" or collectively as the "**Parties**").

RECITALS

A. Seller intends to construct, own, operate and maintain a ____________________ ______________________________________ [state type of facility] facility for the generation of electric power, including interconnection facilities, located in ____________________________ [City, County, State] with a Facility Capacity Rating of ___________ -kilowatts (kW) as further described in **Exhibit A** and **Exhibit B ("Facility")**; and

B. Seller intends to commence delivery of Net Output under this Agreement, for the purpose of Start-up Testing, on __________________, 20______ ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on _________________, 20____ ("**Scheduled Commercial Operation Date**"); and

D. Seller estimates that the average annual Net Energy to be delivered by the Facility to PacifiCorp is __________ kilowatt-hours (kWh), which amount of energy PacifiCorp will include in its resource planning; and

E. Seller shall (choose one) ☐ sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp ☐ sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of this Agreement; and

F. This Agreement is a "New QF Contract" under the PacifiCorp Inter-Jurisdictional Cost Allocation Revised Protocol.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1 "**As-built Supplement**" shall be a supplement to **Exhibit A** and **Exhibit B**, provided by Seller following completion of construction of the Facility, describing the Facility as actually built.

1.2 "**Availability**" means the percentage of time that the Facility is capable of producing Net Energy during a Contract Year. The percentage of time during a Contract Year that the Facility is available to produce power is calculated as follows:

% Availability ={[(H x N)-(Sum of Downtime Hrs for N Turbines)]/(H x N)} x 100%

where H is the number of hours in the Contract Year and N is the number of turbines comprising the Facility. Downtime Hours (calculated in 10 minute increments), for each individual unit includes minutes in which the unit is not in "run" status, or is in "run" status but faulted (including any delay in resetting a fault). Notwithstanding the previous sentence, Downtime Hours does not include minutes that a unit is unavailable due to (i) an event of Force Majeure; (ii) a default by PacifiCorp under this Agreement; (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.

1.3 "**Average Annual Generation**" shall have the meaning set forth in Section 4.2.

1.4 "**Billing Period**" means, unless otherwise agreed to, the time period between PacifiCorp's consecutive readings of its power purchase billing meter at the Facility in the normal course of PacifiCorp's business. Such periods typically range between twenty-seven (27) and thirty-four (34) days and may not coincide with calendar months.

1.5 "**Commercial Operation Date**" means the date that the Facility is deemed by PacifiCorp to be fully operational and reliable, which shall require, among other things, that all of the following events have occurred:

1.5.1 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating (a) the Facility Capacity Rating of the Facility at the anticipated Commercial Operation Date; and (b) that the Facility is able to generate electric power reliably in amounts required by

(b) Seller has not at any time defaulted in any of its payment obligations for electricity purchased from PacifiCorp.

(c) Seller is not in default under any of its other agreements and is current on all of its financial obligations, including construction related financial obligations.

(d) Seller owns, and will continue to own for the term of this Agreement, all right, title and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.

(e) **[Applicable only to Seller's with a Facility having a Facility Capacity Rating greater than 3,000 kW]** Seller meets the Credit Requirements.

Seller hereby declares (Seller initial one only):

________ Seller affirms and adopts all warranties of this Section 3.2.8, and therefore is not required to post security under Section 10; or

________ Seller does not affirm and adopt all warranties of this Section 3.2.8, and therefore Seller elects to post the security specified in Section 10.

3.3 Notice. If at any time during this Agreement, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

SECTION 4: DELIVERY OF POWER AND PERFORMANCE GUARANTEE

4.1 Commencing on the Commercial Operation Date, unless otherwise provided herein, Seller will sell and PacifiCorp will purchase all Net Output from the Facility delivered to the Point of Delivery.

4.2 Average Annual Generation. Seller estimates that the Facility will generate, on average, ______________ kWh per Contract Year ("**Average Annual Generation**"). Seller may, upon at least six months prior written notice, modify the Average Annual Generation every other Contract Year.

4.3 Performance Guaranty.

4.3.1 Guaranteed Availability. Seller guarantees that the annual Availability of the Facility (the **"Guaranteed Availability"**) for (i) the first Contract Year shall be no less than 0.80, and (ii) for the second Contract Year shall be no less than 0.85. Beginning with the third Contract Year and for each Contract Year thereafter, the Guaranteed Availability for each Contract Year shall be 0.875, with such annual Availability to be calculated for purposes of this Section 4.3.1 for each Contract Year.

4.3.2 Liquidated Damages for Output Shortfall. If the Availability in any given Contract Year falls below the Guaranteed Availability for that Contract Year, the resulting shortfall shall be expressed in kWh as the **"Output Shortfall."** The Output Shortfall shall be calculated in accordance with the following formula:

Output Shortfall = (Guaranteed Availability – Availability) x Average Annual Generation

If an Output Shortfall occurs in any given Contract Year, Seller may owe PacifiCorp liquidated damages in accordance with Section 11. Each Party agrees and acknowledges that (a) the damages that PacifiCorp would incur due to the Facility's failure to achieve the Guaranteed Availability would be difficult or impossible to predict with certainty, and (b) the liquidated damages contemplated by Section 11 are a fair and reasonable calculation of such damages.

4.4 Energy Delivery Schedule. Seller has provided a monthly schedule of Net Energy expected to be delivered by the Facility (**"Energy Delivery Schedule"**), incorporated into **Exhibit D**.

SECTION 5: PURCHASE PRICES

5.1 Seller shall have the option to select one of four pricing options: Fixed Avoided Cost Prices ("Fixed Price"), Firm Market Indexed Avoided Cost Prices ("Firm Electric Market"), Gas Market Indexed Avoided Cost Prices ("Gas Market"), or Banded Gas Market Indexed Avoided Cost Prices ("Banded Gas Market"), as published in Schedule 37. Once an option is selected the option will remain in effect for the duration of the Facility's contract. Seller has selected the following (Seller to initial one):

_______ Fixed Price

_______ Firm Electric Market

_______ Gas Market

_______ Banded Gas Market

A copy of Schedule 37, and a table summarizing the purchase prices under the pricing option selected by Seller, is attached as **Exhibit G.**

notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

SECTION 11: DEFAULTS AND REMEDIES

11.1 Events of Default. The following events shall constitute defaults under this Agreement:

11.1.1 Breach of Material Term. Failure of a Party to perform any material obligation imposed upon that Party by this Agreement (including but not limited to failure by Seller to meet any deadline set forth in Section 2) or breach by a Party of a representation or warranty set forth in this Agreement.

11.1.2 Default on Other Agreements. Seller's failure to cure any default under any commercial or financing agreements or instrument (including the Generation Interconnection Agreement) within the time allowed for a cure under such agreement or instrument.

11.1.3 Insolvency. A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.

11.1.4 Material Adverse Change. A Material Adverse Change has occurred with respect to Seller and Seller fails to provide such performance assurances as are reasonably requested by PacifiCorp, including without limitation the posting of additional Default Security, within thirty (30) days from the date of such request;

11.1.5 Delayed Commercial Operations. Seller's failure to achieve the Commercial Operation Date by the Scheduled Commercial Operation Date.

11.1.6 Underdelivery. If Seller's Facility has a Facility Capacity Rating of 100 kW or less, Seller's failure to satisfy an Availability of forty percent (40%) or more for two (2) consecutive years; else Seller's failure to satisfy an Availability of fifty percent (50%) or more for one year.

11.2 Notice; Opportunity to Cure.

11.2.1 Notice. In the event of any default hereunder, the non-defaulting Party must notify the defaulting Party in writing of the circumstances indicating the default and outlining the requirements to cure the default.

11.2.2 Opportunity to Cure. A Party defaulting under Section 11.1.1 or 11.1.5 shall have thirty (30) days to cure after receipt of proper notice from the non-defaulting Party. This thirty (30) day period shall be extended by an additional ninety (90) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional ninety (90) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

11.2.3 Seller Default Under Other Agreements. Seller shall cause any notices of default under any of its commercial or financing agreements or instruments to be sent by the other party to such agreements or instruments, or immediately forwarded, to PacifiCorp as a notice in accordance with Section 23.

11.2.4 Seller Delinquent on Construction-related Financial Obligations. Seller promptly shall notify PacifiCorp (or cause PacifiCorp to be notified) anytime it becomes delinquent under any construction related financing agreement or instrument related to the Facility. Such delinquency may constitute a Material Adverse Change, subject to Section 11.1.4.

11.3 Termination.

11.3.1 Notice of Termination. If a default described herein has not been cured within the prescribed time, above, the non-defaulting Party may terminate this Agreement at its sole discretion by delivering written notice to the other Party and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement; *provided, however* that PacifiCorp shall not terminate: (a) for a default under Section 11.1.5 unless PacifiCorp is in a resource deficient state during the period Commercial Operation is delayed; or (b) for a default under Section 11.1.6, unless such default is material. The rights provided in Section 10 and this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. Further, the Parties may by mutual written agreement amend this Agreement in lieu of a Party's exercise of its right to terminate.

11.3.2 In the event this Agreement is terminated because of Seller's default and Seller wishes to again sell Net Output to PacifiCorp following such termination, PacifiCorp in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the Termination Date (as set forth in Section 2.4). At such time Seller and PacifiCorp agree to execute a written document ratifying the terms of this Agreement.

11.3.3 Damages. If this Agreement is terminated as a result of Seller's default, Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for the Average Annual Generation that Seller was otherwise obligated to provide at the Guaranteed Availability for a period of twenty-four (24) months from the date of termination, plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, plus the estimated administrative cost to the utility to acquire replacement power. Amounts owed by Seller pursuant to this paragraph shall be due within five (5) business days after any invoice from PacifiCorp for the same.

11.3.4 If this Agreement is terminated because of Seller's default, PacifiCorp may foreclose upon any security provided pursuant to Section 10 to satisfy any amounts that Seller owes PacifiCorp arising from such default.

11.4 Damages.

11.4.1 Failure to Deliver Net Output. In the event of Seller default under Subsection 11.1.5 or Subsection 11.1.6, then Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for any Output Shortfall (under Section 4.3) during the period of default ("**Net Replacement Power Costs**"); *provided, however,* that the positive difference obtained by subtracting the Contract Price from the Replacement Price shall not exceed the Contract Price, and the period of default under this Section 11.4.1 shall not exceed one Contract Year.

11.4.2 Recoupment of Damages.

(a) Default Security Available. If Seller has posted Default Security, PacifiCorp may draw upon that security to satisfy any damages, above.

(b) Default Security Unavailable. If Seller has not posted Default Security, or if PacifiCorp has exhausted the Default Security, PacifiCorp may collect any remaining amount owing by partially withholding future payments to Seller over a reasonable period of time, which period shall not be less than the period over which the default occurred. PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller's default on its commercial or financing agreements necessary for its continued operation of the Facility.

SECTION 12: INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. Seller shall release, indemnify and hold harmless PacifiCorp, its directors, officers, agents, and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Point of Delivery, (b) any facilities on Seller's side of the Point of Delivery, (c) Seller's operation and/or maintenance of the Facility, or (d) arising from this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PacifiCorp, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of PacifiCorp, its directors, officers, employees, agents or representatives.

12.1.2 Indemnity by PacifiCorp. PacifiCorp shall release, indemnify and hold harmless Seller, its directors, officers, agents, Lenders and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Point of Delivery, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents, Lenders or representatives.

12.2 No Dedication. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.3 No Consequential Damages. Except to the extent such damages are included in the liquidated damages, delay damages, cost to cover damages or other specified measure of damages expressly provided for in this Agreement, neither Party shall be liable to the other Party

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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

Community Renewable Energy Association

Exhibit 105

Excerpts of Stoel Rives Publication on MAGs

March 18, 2013

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Chapter Seven
THE LAW OF WIND
—Power Purchase Agreements and Environmental Attributes—

Teresa A. Hill, William H. Holmes, Jennifer H. Martin

I. The Parties.

A. **The Seller.** The seller is often the developer and owner of a wind plant that will generate energy and environmental attributes ("output"). But the seller may also be a power marketer that is buying the output of a plant and selling it to one or more purchasers. If a company is reselling output, the resale power purchase agreement (the "PPA") will usually track the relevant terms of the underlying PPA because the marketer will not want to promise more than it has the right to deliver. As a result, the marketer will often use a "back-to-back" PPA for the resale. The resulting terms will be almost the same as those in the underlying project PPA, except for price or other unique items that the marketer does not wish to pass through to the ultimate buyer.

B. **The Buyer.** The buyer is often a utility that purchases the wind project's output to serve its load. The utility may also be motivated by a "renewable-portfolio standard" or other regulatory policy that encourages the development of wind power and other forms of renewable energy. The significance of this driver is growing, as 28 states now have renewable portfolio standards, and a national renewable portfolio standard in some form is likely to be enacted in the near future. In a state that permits direct access or allows renewable energy to be sold at retail, the buyer may be a retail purchaser, such as a manufacturing facility that wishes to hold itself out as a green company. Power marketers may also buy output for resale to one or more third parties. Power marketers sometimes can purchase all of a project's output (something that no other single-market player may be able to do), taking a "merchant position" and enabling the owner to finance the plant.

C. **Credit Support Provider.** The PPA will require the buyer to buy the output that the seller delivers. It may also require the seller to pay the buyer if the project is not built on schedule or fails to achieve certain performance standards. Each party will be concerned about the other's ability to satisfy these payment obligations. If one party is not creditworthy, the other may require it to provide a guaranty or post a letter of credit or other security to ensure that amounts due under the PPA will be paid.

II. The Term.

A. **Project Financing.** If the wind plant is financed with limited recourse financing, the term of the PPA should be sufficient to amortize the project debt. Capital costs per megawatt hour ("MWh") of energy produced are relatively high for wind plants because they produce only when the wind is blowing. Thus a wind farm with an installed capacity of 100 MW and a 33 percent capacity factor will, on average, produce only 33 average MW of electricity. To produce the revenues needed to amortize the project debt, the term of the PPA must usually be in the range of at least 20 years.

If the term of the PPA is 20 years, lenders will generally be willing to amortize the debt over a 15- to 17-year period. In project financings, the debt amortization period generally needs to be shorter than the PPA term to allow "work-out time" in case the project encounters financial difficulties in later years. Generally, only the base term of the PPA is taken into account because the lender has no assurance that the purchaser will elect to continue the PPA into a renewal term.

In general, a shaping agreement allows a project to deliver energy into the utility's system as the energy is generated. The intermittent energy serves the utility's load. In the following week or month, the utility redelivers the energy that it has received as a flat product at an agreed-on point of delivery. Not surprisingly, the utility will charge a fee for this service. Shaping can also be accomplished through market transactions, but this typically requires the developer or the nonutility provider of the shaping services to have access to a sophisticated trading desk.

VI. Performance Incentives. A seller will usually prefer to enter into an "as-delivered" PPA, which means that the seller is obligated to deliver only what the project actually produces. A buyer will often require the seller to warrant or guarantee that the project will meet certain performance standards. Such guarantees usually enable the buyer to recover all or part of its incremental cost of purchasing replacement power and environmental attributes in the market to the extent that the project fails to perform as expected. Performance guarantees enable the buyer to plan around the plant's expected output for both load and, if applicable, renewable-portfolio standard compliance, and strongly encourage the seller to maintain a reliable and productive project.

A. Output Guarantees. The PPA may include an output guarantee to the buyer. An output guarantee requires the seller to pay the buyer if the project's output over a specified period fails to meet a specified level, after taking into account output lost because of force majeure or maintenance or other agreed-on subtractors. The period may be seasonal, annual, biannual, or longer (although seasonal guarantees are unusual in today's PPA market). The PPA usually allows the owner to operate the project for one or two years before the output test is applied, enabling the owner to fix any problems at the project and may calculate the guarantee on a two- to three-year rolling average to minimize the impact of particularly low or high wind years. The owner should offer such a guarantee only if very confident about the project's wind regime, wind variability, and capacity factor.

Wind turbine manufacturers generally do not provide output warranties to project developers. Rather, the project owner assumes the risk that the wind at the project will produce enough energy to meet the project's revenue requirements.

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.

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.

C. Power-Curve Warranties. Wind turbine manufacturers also may warrant the ability of the turbines to produce a specified output at specified wind speeds. The power curve represents a calculation of the amount of energy that the turbines are rated to produce at different wind speeds. Power-curve warranties are

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intended to compensate the project owner for lost revenues resulting from inefficient turbine operation, *i.e.,* the failure of turbines to operate within a certain percentage (typically 95 percent) of the power curve. Power curve warranties are not usually passed through to buyers under PPAs.

D. **Liquidated Damages.** If a guarantee is not met, the PPA usually provides a mechanism for determining the damages suffered by the buyer. First, the parties determine the output shortfall (stated in MWhs) relative to the amount of output that the buyer would have received had the project lived up to its guarantees. Second, the shortfall is multiplied by a price per MWh determined by reference to an agreed-on index. Because market indexes currently cover only power prices and do not include the value of environmental attributes, the PPA may include an adjustment to account for the assumed value of the environmental attributes or may use a firm price index as a proxy for the value of the energy plus the environmental attributes. The amount of liquidated damages is usually determined once per year. The seller pays the liquidated damages to the buyer or credits the damages against amounts owed by the buyer under the PPA. The seller may in addition seek to include the right to cure any output shortfall through delivery of replacement energy and environmental attributes at its option where seller and buyer can mutually agree on the time and place for such replacement deliveries. In any case, the seller will likely seek to cap liquidated damages or its replacement obligation on an annual or aggregate basis.

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

VII. Curtailment and Force Majeure.

A. **Curtailment.** The PPA often describes circumstances in which either party has a right to curtail output. For example, the seller may have a right to curtail deliveries if the plant is affected by an emergency condition. The PPA may permit the buyer to curtail for convenience, in which case the PPA usually requires the buyer to pay the purchase price for the curtailed generation and the after-tax value of the production tax credits that the seller would have earned had the buyer not curtailed the plant's output. Facility curtailments caused by transmission congestion or conditions beyond the point of delivery are often handled in the same manner, although the topic of curtailment is frequently a difficult issue in PPA negotiations.

B. **Force Majeure.** If energy is curtailed at a party's discretion or because the party is at fault, the PPA usually requires the curtailing party to pay damages to the other. If curtailment is caused by an event beyond a party's control, the party's duty to perform under the PPA may be excused. For example, if a disaster disables the transformer at the delivery point, the seller would be excused from delivering energy, and the buyer would be excused from taking and paying for energy, until the transformer is repaired. The party responsible for maintaining the transformer would, of course, be required to use diligent efforts to make repairs.

Parties often heavily negotiate force majeure provisions. Good provisions should carefully distinguish between events that constitute "excuses" (which relieve the affected party from its duty to perform) and those that are "risks" (which are simply allocated to a party). The ability to buy energy and environmental attributes at a lower price or sell them at a higher price is generally not a force majeure event. Moreover, a party's inability to pay should not constitute a force majeure event under the PPA. A well-drafted force majeure clause will usually list a

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Chapter Nine
THE LAW OF WIND
—Project Finance for Wind Power Projects—

Edward D. Einowski

I. Introduction.

A. **The Search for Credit.** The essence of wind farm debt financing—as with other electric generation projects—is the search for credit: the fashioning of a loan package that provides adequate assurance (creditworthiness) that the loan will be repaid in a timely manner. Alternatively stated, it is the fashioning of a loan/credit package such that the risk of default (nonpayment) is minimized—reduced or mitigated to bring the risk within levels acceptable to the lender. Creditworthiness and risk are thus two sides of the same coin: the greater the risk, the lower the creditworthiness, and vice versa.

B. **Risk Shifting.** To the extent there is drama involved in putting together wind farm debt financing, much of it derives from the efforts of each participant to shift the various risks to others, while retaining the benefits from the transaction that the participant seeks. The project owner seeks to shift the technology risks to the turbine manufacturer and the construction contractor, while preserving for itself as much of the cash flow and appreciation in project value as possible. The lender seeks to shift the risks to the project owner by taking paramount positions in the project revenues and assets, and to third parties such as the turbine manufacturer and construction contractor by getting the benefit of the warranties and contractual obligations of these participants, all to enhance the prospects of the loan being repaid on schedule.

This risk shifting is accomplished by various legal undertakings by the participants: mortgages and security interests granted in the project assets, revenues, and key project agreements; warranties and contractual requirements for the equipment and the work performed in making it operational; requirements for various types of insurance requirements to cover certain adverse events; and guarantees of each participant's obligations from creditworthy entities. The negotiation and documentation of these risk-shifting devices is the focus of activity in project debt financing, resulting in loan documentation of substantial heft and complexity.

In broad terms, there are two basic approaches to addressing the credit/risk allocation issues in a manner that can be made to work (more or less) for all the participants involved: full recourse (or balance sheet) financing, and limited recourse (or project) financing.

II. Full Recourse (Balance Sheet) Financing.

A. **Defined.** With balance sheet financing, the payment of the debt is backed by the legal obligation of an entity with sufficient financial resources (*i.e.*, its balance sheet) to underwrite the risk that the project will be successful and the debt will be repaid. It is "full" recourse in that the lender can enforce payment of the debt out of any and all unencumbered assets of the entity providing the balance sheet support, rather than being limited to the project assets or other specific collateral. On the other hand, balance sheet financing is usually unsecured, with the lender taking no lien on or security interest in any tangible or intangible assets of the borrower.

The balance sheet backing rarely comes from the entity that will serve as the project owner, as these tend to be single-purpose entities ("SPEs") with no substantial assets other than the project. Rather, it most typically is

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Although it is good that the marketplace currently places such a premium on wind power and green tags, the foregoing nevertheless amply shows that the choice of wind as fuel source has very real costs. Far from being free, using wind as a fuel source results in direct, tangible, out-of-pocket costs that are currently far in excess of the costs associated with other fuel sources. Indeed, wind will not be an economically free fuel unless the industry evolves to the point where the all-in, out-of-pocket costs of producing wind power are equal to or less than the all-in, out-of-pocket costs of producing fossil fuel-generated power minus the fossil fuel costs.

G. **Performance Guarantees.** Evaluation of the met study is aimed at addressing one of the key risks associated with wind farms—namely, how often, at what times of the day, and how fast will the wind blow. Moving beyond that, there is the risk associated with the equipment employed. Because wind farms are variable resources that produce revenue only when the wind is blowing, it is essential that the project produce the maximum amount of electricity from the available wind resource in order to produce the maximum amount of revenue. The performance risks are addressed in the various guarantees provided by the turbine manufacturer.

The types of performance guarantees that are usually sought from the turbine manufacturer are as follows:

Not quoted by PGE

Quoted by PGE

Mechanical Availability: The mechanical-availability guarantee is aimed at ensuring the reliability of the turbines—that, from a mechanical standpoint, they will be ready to produce electricity whenever the wind blows. In recent years as the technology has improved, typical mechanical-availability guarantees provide for a guarantee of a mechanical-availability percentage in each contract year of 95 percent. The mechanical-availability percentage is a fraction, the numerator of which is the actual number of hours in the contract year during which the turbines were mechanically available for operation, and the denominator of which is the theoretical number of hours during the contract year in which the turbines could have been mechanically available to produce electricity.[5] To the extent the project falls below the guaranteed mechanical-availability percentage in a given contract year, the turbine manufacturer is liable for liquidated damages, which are usually calculated by reference to the cost of replacement power (or cost to cover) in an amount equal to the forgone production due to failure to meet the guarantee.

Guaranteed Output: Although the mechanical-availability guarantee is aimed at providing assurance that the turbines will be mechanically available to produce electricity, the output guarantee is aimed at ensuring that a certain level of total output (electricity production) will be achieved over time. The output guarantee starts by reference to the project's mean annual output. Mean annual output, in turn, is a negotiated figure usually expressed in terms of a certain number of megawatt hours ("MWh") in each contract year. The output guarantee is typically 75 percent of the mean annual output. The guarantee takes the form of guaranteeing that the average annual output for the calculation period in question (*i.e.*, the actual amount of MWh produced during such period) will be not less than the output guarantee.

It should be noted that the period over which the output guarantee is tested is usually a rolling two-year period, rather than an annual period. By taking the average of two years, one avoids a situation in which a bad wind year

[5] The denominator is essentially the total number of hours in the contract year, less the hours during which the project suffers transmission curtailment, is down for scheduled maintenance, or is down due to a force majeure event other than a purely mechanical event related solely to the turbines.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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

Community Renewable Energy Association

Exhibit 200

Direct Testimony of Dr. Don Reading

March 18, 2013

Table of Contents

<u>I. Introduction</u>

Q. Please state your name and business address.

A. My name is Don Reading and my business address is 6070 Hill Road, Boise, Idaho. I am a principal with Ben Johnson Associates.

Q. Have you prepared an exhibit setting forth your qualifications and professional background?

A. Yes. My professional background and qualifications are included in CREA/201. To summarize, I am a consulting economist with thirty years of experience in the economics field and have testified on over thirty-five occasions before public utility commissions in several different states.

Q. Have you testified regarding qualifying facility policies in previous cases before the Public Utility Commission of Oregon ("Commission" or "OPUC")?

A. Yes. I filed testimony in docket UM 1129, addressing generic qualifying facility ("QF") policies, on behalf of the Sherman County Court and the J.R. Simplot Company.

Q. On whose behalf are you testifying?

A. I am submitting testimony on behalf of the Community Renewable Energy Association ("CREA"). Mr. Ormand Hilderbrand's testimony discusses CREA in more detail.

Q. What is the purpose of your testimony?

A. I will provide testimony in response to 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 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). 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"). A summary of my recommendations on the issues in my testimony is included in CREA/101, which also includes a summary of CREA's recommendations made through the testimony of Mr. Ormand Hilderbrand and Mr. Tom Svendsen.

Q. Please summarize your recommendations.

A. In general, I disagree with several of the suggestions of the IOUs that would reverse Oregon's modest policies aimed at providing a fair and stable environment for qualifying facilities and encourage the development of renewable generating resources in the state. I testified in UM 1129 and my opinions today parallel those filed in that docket. I recommend the Oregon 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.

II. Issue 1: Avoided Cost Price Calculation

Issue 1. A. What is the most appropriate methodology for calculating avoided cost prices?

Q. Are you familiar with the methodology for setting the utilities' currently effective standard avoided cost rates?

A. Yes. Under the current methodology approved by the OPUC, when a utility is in a resource deficient position, the rate is supposed to reflect the variable and fixed costs of the next avoidable resource identified in the utility's Integrated Resource Plan ("IRP"). This is essentially a proxy method, which at this time for the non-renewable avoided cost rates is based upon the costs of building and operating a gas-fired plant. The utilities publish a standard rate available for all QFs 10 MW and under, and that rate is the basis for negotiations for contracts above that size threshold.

Q. Do you believe that the reasoning behind this methodology is sound?

A. Yes. The basis of the rate is that the QF energy and capacity allows the utility to avoid incremental additions of the next avoidable resource identified in the IRP. Although the utilities argue that this approach over-values the QF power for various reasons, my review of the work papers and discovery reveals that the utilities' critiques fail to take into consideration all of the benefits that QFs provide to the system.

Q. Do you agree with the utilities' proposals to change this methodology?

A. I do not believe major changes are needed for the current system. At least two of the utilities partially acknowledge the merits of the current methodology. PacifiCorp advocates for the continued use of the existing proxy method albeit limiting its use for standard rates for projects sized 3 MW.[1] PGE states, "The current method provides a fair and accurate measure of avoided cost, and thus we recommend its continuation." However, PGE advocates a 100 kW eligibility cap for all PURPA resources. Though not entirely clear, PGE states there should be distinctions made between the resource types (renewable and traditional) with regard to the trigger for the deficiency period.[2] Both of these utilities proposed to continue the use of their modeling methods previously approved by the Commission for projects larger than the cap. I will address proposals to lower the eligibility cap in detail below.

Q. Idaho Power proposes more significant changes to the methodology. Could you summarize your understanding of its proposal?

1 PacifiCorp/200, Griswold/16.
2 PGE/100, Macfarlane-Morton/12.

A. Idaho Power advocates for a radical departure from the current method of calculating avoided costs in Oregon. For projects eligible for standard rates, Idaho Power proposes to separately calculate the energy and capacity components of the rate based on resource type.[3] In this manner, different resource types would receive a different rate based on the QF's assumed capacity contribution during the peak-hour load period between 3:00 p.m. and 7:00 p.m. in July. For example, a peak-hour capacity factor for hydro is 33.9%, while a canal drop hydro is 67.1%, wind is 3.9%, and solar is 33.2%.

For the calculation of standard rates, this approach adds unnecessary complexity and will allow for potential gaming by the utility. In addition, it will require more time and resources for the validity of the assumptions made by the Company to be vetted by both the QFs and the Commission. Because the other utilities have not advocated these adjustments to capacity, it will add confusion about what standard rates are in Oregon and where they should apply. I do not recommend that Idaho Power's proposal be adopted for standard rates.

Q. Is that the only major change Idaho Power proposes?

A. No. Idaho Power also proposes a major change for the calculation of rates for projects too large to be eligible for standard rates. For projects over the eligibility cap size, Idaho Power proposes to use a "single-run" methodology with its power supply model to calculate the avoided cost rates.[4] Because Idaho Power proposes to lower the eligibility cap to 100 kW for wind and solar, this methodology would apply to wind and solar projects.

Idaho Power is proposing a single run of their AURORA model that calculates avoided energy costs equal to the cost of the Company's most expensive unit forecasted to be on-line for each hour of each year for the contract term. This methodology underpays QFs by estimating

[3] Idaho Power/200, Stokes/26.
[4] Idaho Power/200, Stokes/29-44.

avoided cost on a *very* short-run hourly basis.

In addition, the method proposed by Idaho Power removes surplus sales from the AURORA model runs. According to Mr. Stokes, "Under the incremental cost IRP methodology, the QF generation does not support surplus sales, it is simply valued at the highest displaceable incremental cost Idaho Power is incurring during the hour."[5] This removal of surplus sales before calculating avoided cost fails to consider the contribution to surplus sales from the output of QFs. Because QFs are part of the utility resource mix and produce power as an integrated part of the system, to deprive them of the utilities' benefits from the surplus sales ignores the full value the QFs contribute.

Q. What is the effect of Idaho Power's proposal?

A. It arbitrarily and unfairly reduces the value of avoided costs and puts QFs on an unequal footing with the Company's own resources. When the Company wants to build one of its own resources, it does not simply run AURORA and then ask the Commission for rate recovery based only on the value of the highest cost resource in the stack in every given hour over the life of the plant. Additionally, when Idaho Power plans to build its own resources, it factors the value of the off-system sales from the resource into the economics of resource decisions because off-system sales are an integral part of how Idaho Power operates its system. Off-system sales make the value of Idaho Power's own resources more cost-effective in planning processes, and they should likewise make the economics of QF resources more economical in setting the avoided cost rates.

Q. Idaho Power stated that its "single run" methodology better aligns its avoided cost methodology with FERC's definition of avoided cost. Do you agree?

[5] Idaho Power/200, Stokes/34.

A. No. Although Idaho Power states its methodology better aligns with FERC's definition of avoided cost, FERC specifically described a "double-run" methodology as being appropriate when defining avoided costs. FERC's avoided cost rule states: "Avoided costs mean the incremental cost to an electric utility of electrical energy or capacity or both which, *but for the purchase from the qualifying facility* or qualifying facilities, such utility would generate itself or purchase."[6]

In explaining this concept, FERC directly endorsed the double-run methodology Idaho Power believes to be inconsistent with FERC's avoided cost rule. FERC stated:

> One way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan, excluding the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan including the qualifying facility.[7]

Under Idaho Power's single-run proposal it is impossible to calculate a utility's avoided costs due to the addition of a QF to its resource stack. QFs ineligible for standard rates would

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6 18 C.F.R. § 292.101(6) (emphasis added).

7 *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978* ("*Order No. 69*"), 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980) (footnote omitted).

not only need to negotiate rates with the utility, but they would also be guaranteed a rate that does not pay the full avoided costs.

Q. Idaho Power's witness, Mark Stokes, discusses at length the impact of PURPA generation, especially wind, on the Company's system and the harm he believes that these projects are imposing on customers. Do you agree with his conclusions?

A. No. Mr. Stokes presents a chart on page 15 of his direct testimony that compares the average per MWh cost of Idaho Power's PURPA contracts along with past and projected Mid-C prices.[8] Mr. Stokes ignores that ratepayers are paying more for the generation from the Company's own resources than Mid-C prices when the associated rate base and fuel costs are considered. He also fails to consider the value of the reduction in fuel cost risk these renewable resources and all fixed price QF contracts provide. A recent study by the Lawrence Berkeley National Laboratory analyzes the long-run hedging value of wind given current low natural gas prices.[9]

The study points out that while short-term gas price risk can be hedged using conventional instruments (five or ten years), longer term hedges are not available. This fact along with the fact that the cost of long-term, fixed rate wind PPAs will cost no more per MWh twenty years from now as they do today is important. The study states:

> Comparing the wind PPA sample to the range of long-term gas price projections reveals that even in today's low gas price environment, and with the promise of shale gas having driven down future gas price expectations, wind power can still provide long-term protection against many of the higher-priced natural gas

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8 Idaho Power/200, Stokes/15.

9 Mark Bolinger, *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, (Lawrence Berkeley National Laboratory, March 2013), available online at http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf (last accessed March 16, 2013).

scenarios contemplated by the [Energy Information Administration] EIA. This is particularly true among the most recent wind PPAs in the sample, which likely better represent current wind pricing, at least on a national average basis. These newer wind contracts not only provide ample long-term hedge value, but on average are also directly competitive with gas-fired generation in the near term.[10]

Over time these "free fuel" wind projects are of benefit both to a utility and its customers by hedging against the risk of an increase in natural gas prices sometime in the future. In fact, the study concludes by stating, "The corresponding expansion of gas-fired generation in the power sector – driven primarily by lower natural gas prices – has also made it easier and cheaper to integrate large amounts of variable renewable generation, such as wind power, into the grid."[11] Therefore, it is in the interest of benefiting customers that the Commission should establish policies that encourage, rather than deter, renewable resources as both PURPA and the Oregon Legislature require.

Q. What is your recommendation?

A. There has been no compelling case made that the Commission's implementation of PURPA since UM 1129 has harmed ratepayers. Instead, the avoided cost rates have provided a fair and transparent way for small renewable energy projects to access the market. I recommend that the Commission retain the current method based on the cost of the next avoidable utility scale generation resource identified in the company's current IRP, which at the present time are gas-fired power plants.

Q. Should the methodology be the same for all three electric utilities operating in Oregon?

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[10] *Id.* p. i.
[11] *Id.* at p. 22.

A. Yes, the methodology should be the same for all three electric utilities, at least with regard to calculating the standard (non-renewable) avoided cost rates. All three utilities are currently constructing or planning to construct gas-fired power plants as their next avoidable resource. Continuing to base the avoided cost rate calculation on the next avoidable resource in the utility's IRP is reasonable. In the interest of administrative efficiency and transparency, I recommend the Commission utilize the same methodology for all three utilities. While there can be different ways to calculate avoided costs, those used by Commission in UM 1129 are widely accepted and there is no compelling reason to change.

As noted above, I believe that Idaho Power's proposal to differentiate standard rates based on each different resource type will undermine the purpose of the standard rates by allowing for gaming by the utility in rate calculation as well as confusing the availability of standard rates for small QFs. I also strongly recommend the Commission not adopt Idaho Power's proposed "single run" methodology for non-standard rates, which Idaho Power proposes to apply to virtually all wind and solar QFs. If the Commission is inclined to adopt these methodologies for Idaho Power to preserve consistency with the Idaho jurisdiction, I recommend that these methodologies not be adopted for PGE and PacifiCorp.

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

Q. Do you believe that the Oregon Commission should provide QFs with the right to elect to have levelized pricing in a long-term contract?

A. Yes. Non-levelized rates vary with the cost of fuel and will be low in the early years of the contract, especially if there is a sufficiency period. This can present a problem for financing a QF project. In contrast, levelized rates are fixed over the life of a contract, essentially resulting in overpayment in early years and underpayment in later years. In Oregon, this may allow small QFs to meet financial payments during the initial years of the contract when a lengthy sufficiency period may result in non-levelized rates that are too low to allow QFs to meet debt service obligations and start-up costs. As I recall, this was important in the early years of QF development in Idaho.

Q. Has FERC ever discussed the use of levelized avoided cost rates?

A. Yes. FERC has specifically authorized use of levelized avoided cost prices. When FERC first promulgated its avoided cost pricing provisions, it determined that QFs should be compensated at the full avoided costs, and it stated:

> A facility which enters into a long term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or non-regulated electric utility from approving such an arrangement.[12]

Q. Are you aware of any other states that allow for levelized pricing?

A. Yes. The State of Idaho has long implemented levelized prices as a way to provide an incentive to QFs without harming ratepayers. The levelization of payments in contracts offered

[12] *Order No. 69*, 45 Fed. Reg. 12,214, 12,224.

to QFs has been litigated in various states and approved by Commissions in Idaho, Florida, and North Carolina .[13]

Q. Do you agree with Idaho Power's position that levelized pricing provides an incentive for the QF to default prior to expiration of the contract?

A. No. I believe that a QF has an incentive to sell as much output as it can throughout the entire term of the agreement. A QF is only compensated for output delivered. I believe levelized pricing helped promote QF development in Idaho, and if properly implemented it could also do so in Oregon, while leaving rate payers indifferent. Idaho Power's concern with levelization centers on overpayments during the early years of the contract. The Company cites one larger project and two smaller projects that defaulted.[14] Idaho Power's witness Stokes states that the Company has 60 contracts that contain levelized rates, however in the last 13 years only 5 of the 51 projects have elected the option of levelized rates. Since the majority of the contracts with levelized rates are at least 13 years old it is reasonable to assume that meaningful overpayments due to levelization should not be a problem for the utility.[15]

Also, as I recall, the Idaho Commission eliminated the use of the surplus or sufficiency period in QF contracts in 2002, which is around the same time that Mr. Stokes appears to argue Idaho QFs' interest in levelized rates began to decline. Without a sufficiency period, the levelization of rates may not be as important because the higher deficiency period rates would be available in the early years of the contract even with non-levelized rates. However, there is

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[13] Carolyn Elefant, *Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies In Supporting Alternative Energy Development and A Proposed Path for Reform*, at pp. 33-34 (October, 2011) , available online at http://www.recycled-energy.com/images/uploads/Reviving-PURPA.pdf (last accessed March 16, 2013).

[14] Idaho Power/200, Stokes/75-76.

[15] Idaho Power/200, Stokes/75, 77.

currently a sufficiency period in Oregon, and it is likely Oregon QFs would elect levelized rates if they were available.

Q. Does Idaho Power have any other arguments against levelization of rates?

A. In addition, Mr. Stokes expresses concern that QFs structured as special purpose entities will have no assets for Idaho Power to collect in the event of a default prior to the repayment of the over-payment in the early years. This overlooks the fact that once a QF is built, the special purpose entity does possess assets that Idaho Power could access. Additionally, the Idaho Commission has addressed this concern by requiring that QFs taking levelized rates maintain a certain amount of security in the event of a default. There are ways to address Mr. Stokes' concern with defaults.

I would also note that Idaho Power's position on levelization of rates is inconsistent with other elements of his testimony. Mr. Stokes states at the beginning of his testimony that, "Idaho Power proposes that the Commission continue its longstanding practice of allowing Idaho Power to use avoided cost methodologies and contracting practices in its Oregon jurisdiction that are consistent with those that the Company utilizes in its Idaho jurisdiction."[16] However, Idaho Power is also inconsistently recommending levelization not be allowed by the Oregon Commission as opposed to the levelization ordered by the Idaho Commission.

The Commission should not deny the levelization of rates for the few QF projects who may need such a rate structure to be able to develop their projects. During periods with a lengthy surplus period, levelization would allow QFs to build smaller increments of capacity on the system during that surplus period while leaving ratepayers indifferent over the life of the contract.

[16] Idaho Power/200, Stokes/3.

Issue 1. C. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different than the market price?

Q. Do you believe that existing QFs renewing a contract should be provided the full avoided costs of the avoidable resource identified in the IRP, rather than only the market prices during the sufficiency period?

A. Yes. The Idaho Commission found in its recently completed docket GNR-E-11-03 that:

> 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 and 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.[17]

These QF resources have not contributed to the utilities short-term period of projected surplus and are currently receiving capacity payments as part of their contract. Therefore, they should not be penalized by receiving reduced payment for the period of projected surplus in their follow-up contract.

Issue 1. D. Should the Commission eliminate unused pricing options?

[17] *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. 32697, at 21-22 (2012).

Q. PacifiCorp proposes to eliminate its gas market indexed and banded gas market indexed options. Do you agree with this proposal?

A. Yes. Because no QFs have requested these pricing options and CREA is not aware of any QFs who may seek these options, I see no reason to object to PacifiCorp's proposal to remove the full rate schedule from the tariff. However, it is possible that some QFs may prefer this option, and the Commission should require the utilities to make these rate options available upon request even if the full rate schedules are not included in the tariff.

III. Issue 4. Price Adjustments for Specific OF Characteristics

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

Q. What did the Commission decide with regard to integration costs for small QFs in UM 1129?

A. The OPUC's existing policy on the matter is that small QFs under 10 MW are not required to pay for wind integration services.[18] OPUC Staff advocated that "for small wind projects under standard contracts, Staff maintains that the method for calculating standard avoided cost rates adopted in Order No. 05-584 is a reasonable estimate of the costs the utility will avoid by purchasing from the small QF and the standard avoided costs should not be adjusted for integration costs."[19] OPUC Staff supported wind integration charges for large QFs, but noted, "if the QF chooses to contract for integration services with a third party, the utility

[18] See OPUC Order No. 07-360 at 24.
[19] *Id.* at 24.

should make no downward adjustment in avoided cost payments for integration costs."[20] The Commission declared, "We agree with Staff."[21] Thus, small wind QFs are not subject to wind integration charges, which are implemented for large QFs either as a reduction to the avoided cost rates or by the QF's agreement in the PPA to secure wind integration from a third party.

Q. Do you see any reason for the Oregon Commission to break from this policy?

A. I do not believe the Commission should break from its prior determination by implementing a wind integration charge for small QFs. These QFs are under 10 MW and should be dispersed geographically on the utility's system. The decision to not implement a wind integration charge for small QFs in UM 1129 was premised on the theory that the benefits small distributed projects provide (as compared to the large-scale projects) should balance out with the costs of wind integration. If the Commission chooses to implement a wind integration charge for small QFs, the Commission should also ensure that Oregon utilities compensate small QFs for the many benefits they provide in the aggregate.

Q. Are the benefits of small QFs documented anywhere?

A. Yes. A 2007 study by the U.S. Department of Energy mandated by the Energy Policy Act ("EPACT") of 2005 analyzed a wide range of specific areas of the aggregate benefits from distributed generation.[22] These included increased electric system reliability, emergency supply of power, reduction of peak power requirements, offsets to investments in generation, transmission, or distribution facilities that would otherwise be recovered through rates, provision of ancillary services, including reactive power, improvements in power quality, reductions in

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[20] *Id.*

[21] *Id.* at 25.

[22] U.S. Dept. of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Its Expansion* (June, 2007), available online at http://www.ferc.gov/legal/fed-sta/exp-study.pdf (last accessed March 17, 2013).

land-use effects and rights-of-way acquisition costs, and a reduction in vulnerability to terrorism and improvements in infrastructure resilience. Most of these potential values are not quantified in the calculation of Oregon's avoided costs even though they do provide real benefits to the electric power grid for customers and the utilities. I will discuss some of these benefits in more detail below when discussing the seven FERC factors.

Q. Have the utilities overlooked any important factors in wind integration costs specific to Oregon QFs under 10 MW.

A. The utilities propose to implement the full wind integration charge for these small Oregon QFs. However, the utilities have not considered in their wind integration studies whether smaller, more geographically dispersed projects impose a lower wind integration cost on the utility. The idea that wind integration costs decrease with geographic diversity is well documented. Also, I am aware of at least one wind integration study by a nearby utility which looked at the issue, and concluded that smaller, dispersed projects impose lower wind integration costs on that utility. The study was recently completed by Northwestern Energy.[23] In the executive summary, the study indicates that smaller, dispersed projects impose a reduced need for reserves as a percentage of nameplate capacity.

Q. If the utilities are permitted to implement some wind integration charge on small QFs, are there other options the Commission should allow for the QF?

A. Yes. Even if each utility's wind integration charge is imposed as a reduction to the standard avoided cost rates for small wind QFs, the charge should not be assessed to wind QFs who choose to partially or fully shape their output prior to delivery to the utility. I understand that some transmission providers assess a wind integration charge and deliver a partially

[23] This wind integration study is available online at http://www.northwesternenergy.com/%5CDocuments%5CDefaultSupply%5CMTWindIntegrationStudy.pdf (last accessed March 16, 2013).

integrated wind output, and also that it is becoming increasingly possible to secure integration services from other third parties. Additionally, the use of batteries is becoming more common, and some wind QFs may choose to balance the output of small QFs with a battery or other storage device.

Q. The utilities appear to propose to use their wind integration charge for solar projects. Do you have any comments on that recommendation?

A. Yes. None of the utilities to this docket have conducted a solar integration study. Solar and wind are two very different resources, and it is well documented that solar projects are easier to integrate into the power system. Even if the Commission decides to implement a wind integration charge for wind QFs, the Commission should not allow for use of a wind integration charge for solar QFs.

Issue 4. B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?

Q. Do you believe that the avoided cost rates should include a price adder to QFs to account for avoided transmission costs associated with utility plants?

A. QFs are responsible for transmission expenses to get their output to the utility's system and for any transmission upgrades to the utility's system necessary to get the QF output to load. I agree with PGE's witnesses that transmission costs should be included in the avoided cost calculation if the avoided resource would impose transmission costs on the utility.[24] For PGE and PacifiCorp, I believe there should be a cost adder included within the avoided cost rates to fully account for the reasonably anticipated transmission costs those utilities would incur with

[24] PGE/100, Macfarlane-Morton/21.

development of their proxy gas-fired plant or market purchases. Because Idaho Power operates a mostly contiguous system and at the present time appears to be able to directly connect its gas-fired resources to that system without the need for major upgrades, a transmission adder may not be necessary for Idaho Power's deficiency period rates.

Q. Are transmission costs included in the calculation of avoided costs by PGE?

A. Based upon PGE's discovery responses, PGE does include adders for wheeling and ancillary services in calculation of the standard avoided cost rates. However, based upon analysis by CREA's witness Tom Svendsen, PGE's cost assumptions do not appear to be as large as those used in PGE's ongoing request for proposals ("RFP") for an actual gas-fired power plant, where PGE reasonably assumed large increases in Bonneville Power Administration ("BPA") transmission rates from PGE's IRP. The assumptions used to calculate the avoided cost rates should likewise include reasonable assumptions for cost increases to transmission rates.

Q. Does PacifiCorp include reasonable assumptions for avoided transmission expense allowed by small QFs in calculating the standard rates?

A. No. PacifiCorp does not include any avoided costs of transmission in estimating avoided costs in its standard avoided cost rates. This is inconsistent with the fact that PacifiCorp must use third-party transmission for its own gas-fired power plants, in order to move their output to PacifiCorp's system and/or around the various load pockets that make up PacifiCorp's west control area. I have included discovery responses on this point as CREA/202. PacifiCorp states that two of its five gas-fired plants are directly connected to BPA's system, and these two plants (Hermiston and Chehalis) are the only two gas-fired plants in PacifiCorp's west control area.[25] These plants must use third-party transmission prior to even reaching PacifiCorp's system.

[25] CREA/202, Reading/1-2.

Q. Are there any other transmission expenses PacifiCorp incurs for its own generation resources?

A. Yes. A map of PacifiCorp's various "load pockets" demonstrates that, unlike PGE and Idaho Power, PacifiCorp's system is strung together by substantial amounts of third-party transmission.[26] PacifiCorp must use third-part transmission for its own gas-fired plants or market purchases in order to operate its system. In fact, PacifiCorp's 2011 FERC Form No. 1 shows that PacifiCorp's 2011 total transmission expense was equivalent to an additional 10% cost over and above PacifiCorp's 2011 total power production expense (including Company-generated power and purchased power). It also showed that approximately 68% of PacifiCorp's transmission expanse was for third-party transmission, and that approximately 47% of PacifiCorp's transmission expense was for BPA transmission. The 2010 BPA transmission expenses amounted to an added expense equivalent to approximately 5% of PacifiCorp's total power production expense. I have provided the relevant excerpts of the 2011 FERC Form No. 1 as CREA/203.

Q. You stated that PacifiCorp does not include this expense in calculation of the avoided cost rates. How would PacifiCorp choose to account for the expense?

A. PacifiCorp proposes to make QFs pay for third-party transmission costs associated with moving their power around PacifiCorp's system whenever a QF interconnects or delivers to a "load pocket" and delivers generation in excess of PacifiCorp's load in the load pocket.[27] However, it should be obvious that PacifiCorp uses extensive third-party transmission for its own non-QF resources. PacifiCorp's proposal is inappropriate unless PacifiCorp is going to include a generic adder in the avoided cost rate calculation to compensate all small QFs who allow

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[26] CREA/202, Reading/5.
[27] PacifiCorp/200, Griswold/10-16.

PacifiCorp to avoid this cost. Additionally, PacifiCorp appears to request the right to adjust the rates up or down in each standard contract after performing some level of transmission studies. This would delay negotiations and present an obstacle to use of standard rates.

Q. Do you have comments on any other transmission related issues?

A. In addition the cost of transmission over the life of a utility resource, it is appropriate to consider deferral of that cost occasioned by incremental additions of smaller capacity QF projects. PacifiCorp does add in a transmission and distribution investment deferral cost credit for Class 2 DSM in its IRP portfolio evaluations. I have included a relevant portion of PacifiCorp's IRP in CREA/204, which is discussed in more detail below. The addition of the credit occurs after the PVRR is run with and without the DSM program, that is similar to the Company's approach used in the determination of avoided costs for the non-standard rates. The value of transmission and distribution investment deferral credit used in the IRP analysis was found to be $54/kW-year for Class 2 DSM cost bundles.[28] Symmetry and fairness would dictate that, if integration costs are deducted from avoided cost rates, then adders should be included to the standard rates for all small QFs to account for the many benefits that QFs provide in the aggregate to the electric grid.

The utilities seem much more focused, in estimating avoided cost, on studying only those factors that may add costs from PURPA projects and ignore those benefits provided by distributed generation. The Commission should require the utilities to examine the benefits, as pointed out above, for inclusion in their future avoided cost filings.

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

Q. What are the FERC seven factors for calculating avoided cost rates?

[28] PacifiCorp's 2011 IRP, at p. 11 (March 2011).

A. The seven factors are as follows:

1. The ability of the utility to dispatch the qualifying facility;
2. The expected or demonstrated reliability of the qualifying facility;
3. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirements, and sanctions for non-compliance;
4. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
5. The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
6. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system;
7. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.

Q. Does FERC require that these factors all be taken into account in calculating standard rates?

A. For standard rates, the seven factors can be taken into account in the "aggregate," as expressly allowed by FERC. Also, the regulation states that these factors are to be taken into account "to the extent practicable."

Q. Do you agree with the utilities that the standard rates over-compensate QFs by failing to take these factors into account?

A. No. The utilities' rate calculations and their testimony in this proceeding fail to properly account for the benefits of small QFs which fall within the parameters of the seven factors, especially aggregate capacity, and the benefit of smaller capacity increments that enable ratepayers to avoid the "lumpiness" of large utility investments.

The utilities' largest complaint appears to be with regard to dispatchability, which is Item 1,18 CPR 292.304(e)(2)(i). According to the utilities, because QFs are must-take facilities and therefore are not dispatchable in the same fashion as a gas proxy, the rate based upon a gas-fired plant is too high. This overlooks that the avoided cost rate using the gas proxy is typically set at a very high capacity factor in the in the calculation of the rate. Based upon PGE's work papers for its avoided cost rate, the assumed capacity factor at the plant is 93%. This high capacity factor spreads the fixed and variable costs over more MWh and decreases the avoided cost rate in $/MWh.

Q. Does a dispatchable plant have a capacity factor of 93%?

A. No. The utilities' dispatchable plants have far lower capacity factors. For example, based on information provided by PGE in discovery, PGE's gas-fired plants had capacity factors of 1% at Beaver, 51% at Port Westward, and 51% at Coyote Springs, in 2012. For each plant the average over their lifetimes since 1996 are as follows: 18% at Beaver, 66% at Coyote, and 66% at Port Westward. The ratepayers essentially make fixed payments to the utility for these plants whether the plants are producing electricity or not, while QFs only receive payment when they deliver electricity. QFs do not receive fixed payments for being available and dispatchable. Consequently, I do not believe that the utilities are paying the QFs to be dispatchable, and that the utilities' complaint that QFs are not dispatchable is unfounded. Additionally, with regard to the renewable avoided cost rates for PGE and PacifiCorp, the rate is based upon a non-dispatchable wind plant. There is no basis to complain that the QFs are not providing dispatchable energy in that circumstance.

Q. The utilities also complain that the rates over-compensate QFs for capacity. Do you agree?

A. No. Item 6, 18 CFR § 292.304(e)(2)(vi), calls for consideration of individual and aggregate capacity. The three utilities in this docket include all of their QF projects in aggregate, as a single generating source, in their IRP planning process. Any given project may experience delivery problems from time to time but when these projects are considered together they provide a fairly predictable supply of power to the system, for both energy and capacity. This means the proxy unit used to calculate avoided costs for projects 10 MW or less is a valid comparative approach for the calculation of the avoided costs of the utility.

Q. Are the utilities accurately calculating all aspects of the standard rates based upon the avoided gas-fired resource?

A. It does not appear so. As mentioned above, at least in the case of PGE and PacifiCorp that use substantial third-party transmission, the utilities do not properly take into account the costs of third-party transmission for a new gas-fired plant. Additionally, I believe that the Commission should require the utilities to better account for the costs of building gas infrastructure in the calculation of the rates based upon a gas-fired plant.

Q. Do you believe all of the factors in projecting the costs to fuel a gas-fired plant have been used to find the avoided cost?

A. No. In reviewing the utility's work papers to calculate the rates based upon an avoided gas-fired resource, it is not clear that the utilities are including appropriate assumptions for the large cost to build a lateral from an existing gas pipeline or storage facility to the new gas-fired power plant. This is a very large expense. For example, publicly available regulatory filings demonstrate that PGE will need to spend in excess of $54 million for the lateral from the existing pipeline system to PGE's proposed Carty Generating Station combined-cycle combustion turbine plant.[29] Other users of the gas system will not subsidize this cost for PGE. Such costly laterals, as well as the ongoing cost for storage rights and pipeline reservations need to be fully included in the avoided cost calculation. Additionally, costs related to use of the existing pipeline system are likely to get larger for new plants because market experts believe that costs of use of the overall gas infrastructure system will increase significantly in the near future.

Q. Could you explain that issue?

A. Natural gas prices are currently very low, and as indicated by the utilities' gas forecasts gas prices are expected to increase only at a slow pace. These gas forecasts are used in the calculation of the cost for the proxy unit generation and thus result in relatively lower avoided costs. However, with the expectation of plentiful gas production and the resulting low prices there is a growing concern in the Northwest about the ability of the gas delivery system to meet the increase in expected demand for low-cost gas. A recent study by the Pacific Northwest Utilities Conference Committee ("PNUCC") and the Northwest Gas Association ("NWGA") indicates a significant increase in gas-fired generation plants in the Northwest in the near future due to projected load and decommissioning of large coal plants.[30] NWGA's 2012 Gas Outlook states that "Based on current data and assumptions, peak day demand could approach or exceed the region's infrastructure capacity within the forecast horizon."[31]

And BPA in an August 2012 white paper indicates:

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[29] FERC recently approved Gas Transmission Northwest LLC's Application to build a 24-mile lateral to serve PGE's Carty CCCT under a long-term contract with PGE at an estimated cost of $54,353,000. *See Gas Transmission Northwest LLC*, 142 FERC ¶ 61,186 (2013).

[30] Power and Natural Gas Planning Task Force, *Natural Gas-Electric Primer*, at p. 6 (August 2012), available online at http://www.ferc.gov/eventcalendar/Files/20120830220205-primer.pdf (last accessed March 16, 2013).

[31] Northwest Gas Association, *2012 Gas Outlook*, p. 13 (2012), available online at http://www.pnucc.org/sites/default/files/NWGA%20Outlook%202012.pdf (last accessed March 16, 2013).

> The Northwest's gas infrastructure currently serves the needs of the region. But it was not built to serve a large-scale generation market and currently operates at 100 percent of capacity during extreme cold-weather peak periods in the winter. At other times of the year, the pipeline system operates at a relatively low load factor, affording significant flexibility. Without infrastructure additions, however, there is no excess capability to serve large new markets on a year-round firm basis.[32]

The increased use of natural gas for electric generation will stress the pipeline delivery infrastructure in the northwest. Many experts expect an increase in LNG exports, an increase in the use of natural gas vehicles, and industrial fuel switching. Expanding pipelines require time and increased expenditures. While production at the well head may remain cheap and plentiful, the ability to get the product to new gas-fired power plants will add to the cost for the ratepayers. These increased delivery costs need to be taken into account in the calculation of avoided costs for the proxy gas-fired unit.

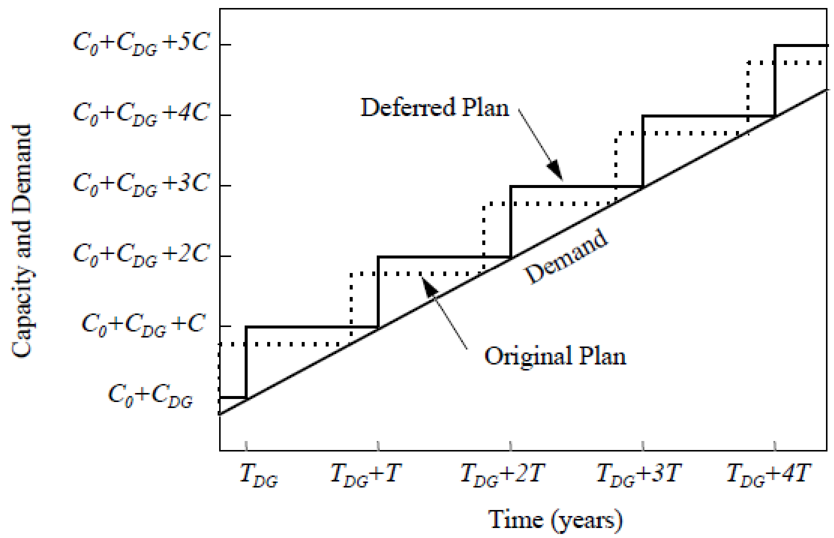
Q. You mentioned that the utilities do not properly take into account the value of deferred investments. Could you explain that issue?

A. Item 7, 18 CFR § 292.304(e)(2)(vii), calls for consideration of smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities. Due to the required lead times, economies of scale, efficiency, etc., utilities tend to add plant in relatively large increments. This means in actual practice, generation capacity is periodically added in a "lumpy" fashion. Therefore, unless due to some unforeseen factor or under-forecasting, a utility will almost always have surplus capacity the next few years into the

32 Bonneville Power Administration, *The Role of Natural Gas in the Northwest's Electric Power Supply*, at p. 1. (August 2012), available online at http://www.pnucc.org/sites/default/files/BPA%20Power-Natural%20Gas%20Whitepaper%208-24-12.pdf (last accessed March 16, 2013).

future. This surplus, unused capacity is paid for by ratepayers, and smoothing out the generation growth path would yield lower costs as the power system grows. Distributed generation capacity, in comparison to a utility's larger generation increments, is added to the system in smaller sizes. There have been several studies that discussed and even quantified the deferral value added by distributed generation.[33]

Below is a figure that illustrates the value of deferring "lumpy" utility investments.[34]



Generally speaking, these studies demonstrate that it is possible to calculate the value of deferred investment in large scale utility projects which distributed generation and targeted demand side

[33] U.S. Dept. of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Its Expansion*, at pp. 3-15 to 3-18(June, 2007); Lambeth, Richard A, *Distributed Photovoltaic Generation: A Comparison of System Costs vs. Benefits for Cocopah Substation*, RFQ #67-9121 (Prepared for Sandia National Laboratories, October 1992); Hoff T., et al., *Identifying Distributed Generation and Demand Side Management Investment Opportunities*, at p. 21 (1996), available for download at http://ideas.repec.org/a/aen/journl/1996v17-04-a04.html(last accessed March 16, 2013); Hoff, T. E., Wenger, H. J. and B. K. Farmer, *Distributed Generation: An Alternative to Electric Utility Investments in System Capacity*, at p. 21 (1996), available online at: http://cleanpower.com/wp-content/uploads/2012/02/041_DG_AlternativeToSystemCapacity.pdf (last accessed March 16, 2013).

[34] Excerpted from Hoff, T. E., Wenger, H. J. and B. K. Farmer, *Distributed Generation: An Alternative to Electric Utility Investments in System Capacity*," Figure 3-11 1996, available online at: http://cleanpower.com/wp-content/uploads/2012/02/041_DG_AlternativeToSystemCapacity.pdf (last accessed March 16, 2013).

management programs allow. This is not a hypothetical cost, but rather a real cost than can be avoided through acquisition of distributed generation of small QFs.

Q. The studies you are referring to above are on utility systems not parties in this docket. Would this analysis apply to the Oregon utilities?

A. Yes, the principles and quantification methods described above would be true of any power system that adds plant in a "lumpy" manner. I did not possess all of the resources necessary to calculate a "lumpiness" cost adder for each of the Oregon utilities for any given project. However, PacifiCorp did calculate investment deferral credits in determining resource timing in a Demand Side Management ("DSM") decrement study in Chapter Two to the Addendum to its 2011 IRP, excerpts of which I have provided as CREA/204.

Q. What does PacifiCorp's study show?

A. In that study, PacifiCorp calculated the value of various DSM efficiency measures, in order to prioritize spending on such measures relative to investing in new resources or power purchase contracts. Class 2 DSM is non-dispatchable energy efficiency, which is a good match to intermittent QFs. PacifiCorp, using a modeling approach similar to the PDDRR method it uses to model QF avoided costs, calculated a \$16.69/MWh benefit attributable to deferred expenditures on new capacity.[35] It also calculated a stochastic risk reduction benefit (compared to fueled capacity resources) of \$14.98/MWh, and deferred transmission and distribution benefits ranging from \$1.75 to \$16.63/MWh.[36]

Q. Has PacifiCorp explained any reason why this theory should not apply to QFs?

A. PacifiCorp has not explained why it embraces the value of deferred investment in new capacity and new transmission and distribution (and avoided fuel risk) in the case of DSM

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35 CREA/204, Reading/4.
36 *Id.*

investments, but not in the case of QF purchases. If these are "real" costs used for purposes of evaluating DSM resources, they should also be evaluated in calculation of the QF rates. In sum, the value to the system from DSM programs that defer plant would be equivalent values from smaller generation additions from PURPA projects. These QF additions smooth out the "lumpy" generation plants built by utilities and thus their value should legitimately be added to avoided cost rates.

Q. How do you conclude that the Commission should use FERC's seven factors in setting avoided cost rates?

A. For small QFs, the Commission should apply the seven factors in the aggregate. The Commission should not accept the argument by the utilities that standard rates over-compensate small QFs for on grounds of dispatchability because standard rates paid for delivered energy do not compensate QFs for dispatchability. In the aggregate, the small QFs allow the utility to defer and avoid large resource acquisitions, and the avoided large resource should be fully accounted for in the rates, including all reasonable cost assumptions for avoided transmission and gas delivery and supply. Additionally, the Commission should include a cost adder to the standard rates to account for the deferral of lumpy utility investments.

IV. Issue 5: Eligibility Issues

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

Q. Do you believe the utilities have provided sufficient justification for the Commission to reverse the decision made in UM 1129 and lower the 10 MW cap for standard contracts?

A. No. The three utilities have proposed a variety of approaches that would change the existing 10 MW cap for a QF standard contract. PacifiCorp advocates lowering the 10 MW cap to 3 MW. PGE recommends the eligibility cap for standard contracts be lowered to 100 kW. Idaho Power is proposing a 100 kW cap for solar and wind projects while maintaining the 10 MW cap for all other project types. While Idaho Power states this is consistent with its Idaho jurisdiction, the cap is actually set at 10 average monthly megawatts for Idaho QFs other than wind and solar QFs.

The Commission considered the issue of the cap for standard contracts in UM 1129 and ordered the cap be moved up from the 2005 level of 1 MW to 10 MW. Now, as then, the utilities are advocating cap levels less than 10 MW. The utilities state a variety of justifications for lowering the cap that include the physical attributes of the QF (disaggregation, intermittent generation), asymmetry aspects of negotiating the contract (the fraction of the project cost, sophistication of project developer, economic resources of developer), FERC's 100 kW lower limit, and the cap limits of surrounding states. The utilities claim that the conditions of QF development are now different than in 2005, when they made many of the same arguments for not raising the cap.

Before dealing with some of the specific points put forth by the utilities a review of Order No. 05-548 indicates the Commission focused on most critical aspect of the case when it stated that a "primary goal in this proceeding is to accurately price QF power." The same is true for this proceeding, even though the point is often lost when dealing with various arguments. If the price is set, as PURPA requires, at the true avoided cost of the utility then the cap level does not take on the ominous aspects claimed by the utilities. As I have noted above, the utilities are currently under-valuing QF energy and capacity in many regards, which cuts against their argument to lower the cap.

Q. What specific responses do you have to the utilities' reasoning?

A. As pointed out by CREA witness, Mr. Ormand Hilderbrand, Oregon's Renewable Portfolio Standard declares that community-based renewable energy projects under 20 MW in size are an essential element of Oregon's energy future, and imposes a goal of providing 8% of load from such community-scale renewable resources. The Commission should develop policies that encourage projects of this size in order to meet this goal. It will be difficult to achieve 8% of Oregon utilities' load with projects under 20 MW if the Commission adopts PGE's proposal to limit standard QF contracts to projects of 100 kW in size, or even PacifiCorp's recommendation to limit standard rates to projects under 3 MW in size.

Q. PGE witnesses Macfarlane – Morton imply that the 10 MW eligibility cap is inconsistent with their understanding of PURPA because the law "recommends" a 100 kW eligibility cap for standard contracts.[37] Do you agree?

A. No. This is a misunderstanding of PURPA regulations. The 100 kW size limit is a floor for standard offers, not a ceiling. States have discretion to establish standard rates for QFs larger than 100 kW. For example, California makes a short-term and long-term standard offer contract available to certain QFs of 20 MW or less and Idaho's standard offer contracts are for 10 average monthly MW or less except for wind and solar.

As stated by the Commission in Order No. 05-584, the most critical aspect of a PURPA proceeding is to accurately price QF power. If this goal is met, then the size of cap, the wealth and size of the developer and the profit (or losses) of the PURPA project should not be a concern. Furthermore, using the sledge hammer to pound down the cap from its current level will only discourage the development of renewable energy in the state.

[37] PGE/100, Macfarlane-Morton/8:14.

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. Does CREA have a position on this issue?

A. Yes. CREA's witness Mr. Ormand Hilderbrand explains it in detail. At this time, CREA believes that the current five-mile separation rule is adequate, but is willing to consider reasonable proposals other parties may make.

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 the eligibility cap should be different for different resources?

A. No. Only Idaho Power proposes a different cap for wind and solar than for other technologies. It is difficult to disaggregate a major resource into smaller QFs when there is a five-mile separation rule. The utilities have not demonstrated there is a problem in Oregon with the size of the eligibility cap for wind and solar projects. However, I understand that CREA would consider reasonable changes to the five-mile rule.

<u>V. Issue 6: Contracting Issues</u>

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

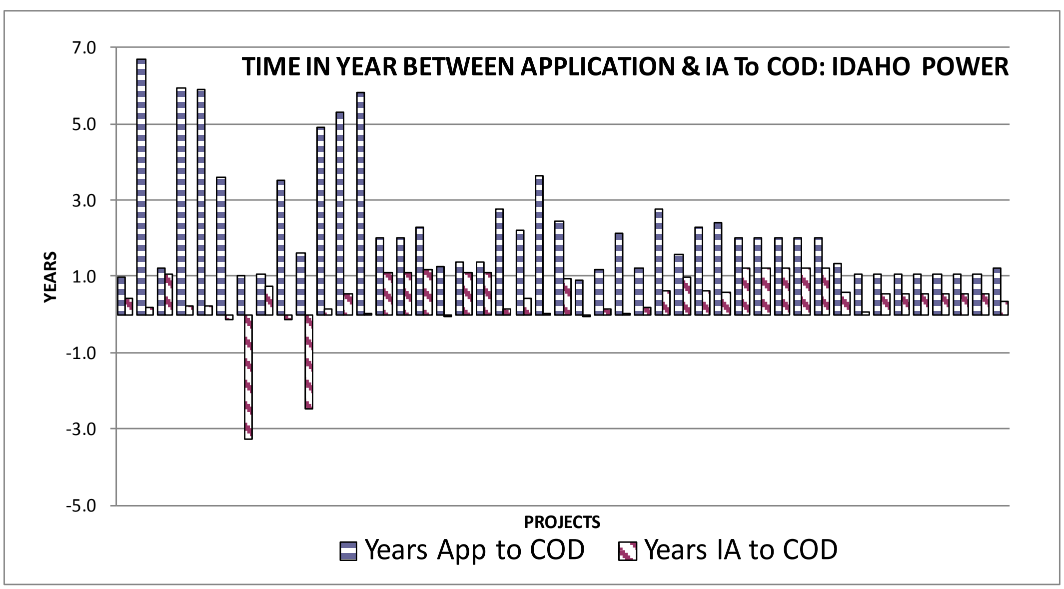
Q. Do you have any comments on the issue of when a legally enforceable obligation ("LEO") is incurred?

A. I recommend on policy grounds that the Commission reject the proposal by PGE that QFs must be online within one year of forming a legally enforceable obligation. In order for most QF projects to get adequate financing, they generally must be able to present the lender a signed contract with payments sufficient to cover the costs of the loan. The time it takes to build a generation facility by either a QF or a utility takes concededly longer than just one year when you include the necessary components of finalizing permitting, land acquisition, engineering, and construction.

Q. Do you have any examples of specific projects that took longer than one year to construct?

A. Yes. According to the Idaho Press Tribune, Idaho Power's just-completed Langley Gulch CCCT took four years: "Construction began July 1, 2010, after over two years of planning. If all goes as planned, it'll go online summer 2012."[38] The plant came on-line in July 2012. For PURPA projects on Idaho Power's system, as shown in Chart One below, the vast majority (84%) took longer than one year from interconnection application to construction completion, with an average time of 2.3 years.

Chart One



Source: Idaho Power Response to REC Request 2.12[39]

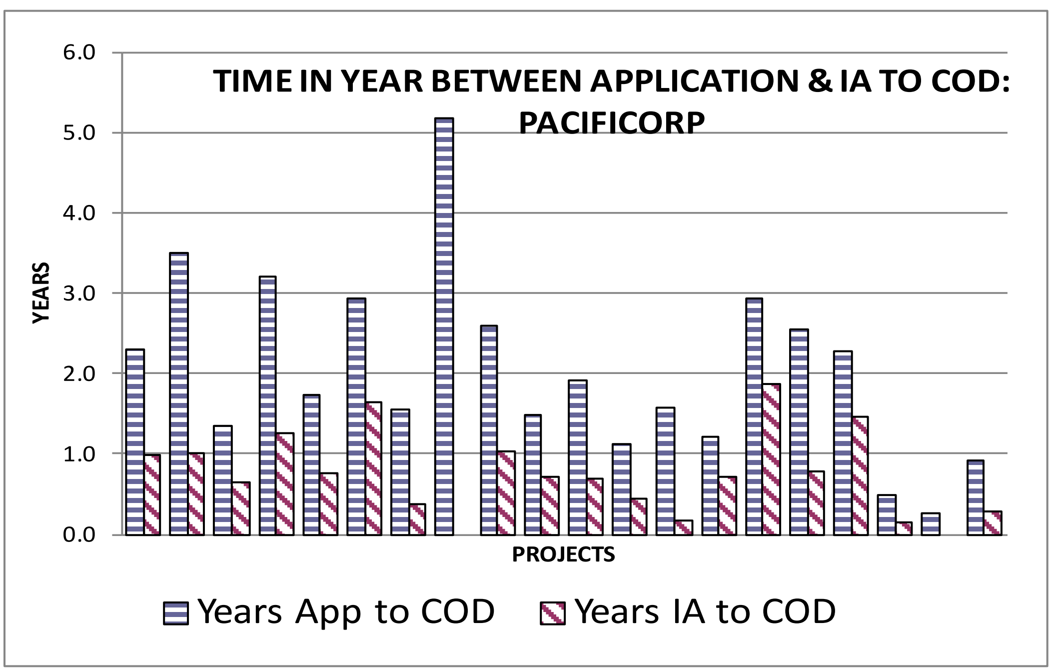
[38] Idaho Press Tribune, September 18, 2011.

[39] The negative numbers in this chart reflect data provided by Idaho Power, and are likely erroneous data entries.

In addition, there were 12 projects with more than a year between the signing of the interconnect agreement and the completion of construction. Even if the interconnection agreement were signed at the same time as the PPA (or formation of the LEO), these QFs still could not meet a requirement to be online within one year because it took longer than one year to construct the interconnection alone. Typically the utility constructs the interconnection, not the QF. The one Oregon project on Idaho Power's system took 3.6 years from application to construction completion.

PURPA projects on PacifiCorp's system mimic those found on Idaho Power's system. As depicted in Chart Two below, only three of the 20 projects took less than one year from application to commercial online date, with one project taking longer than five years. There were five projects that took longer than one year between the signing of the interconnection agreement and construction completion.

Chart Two

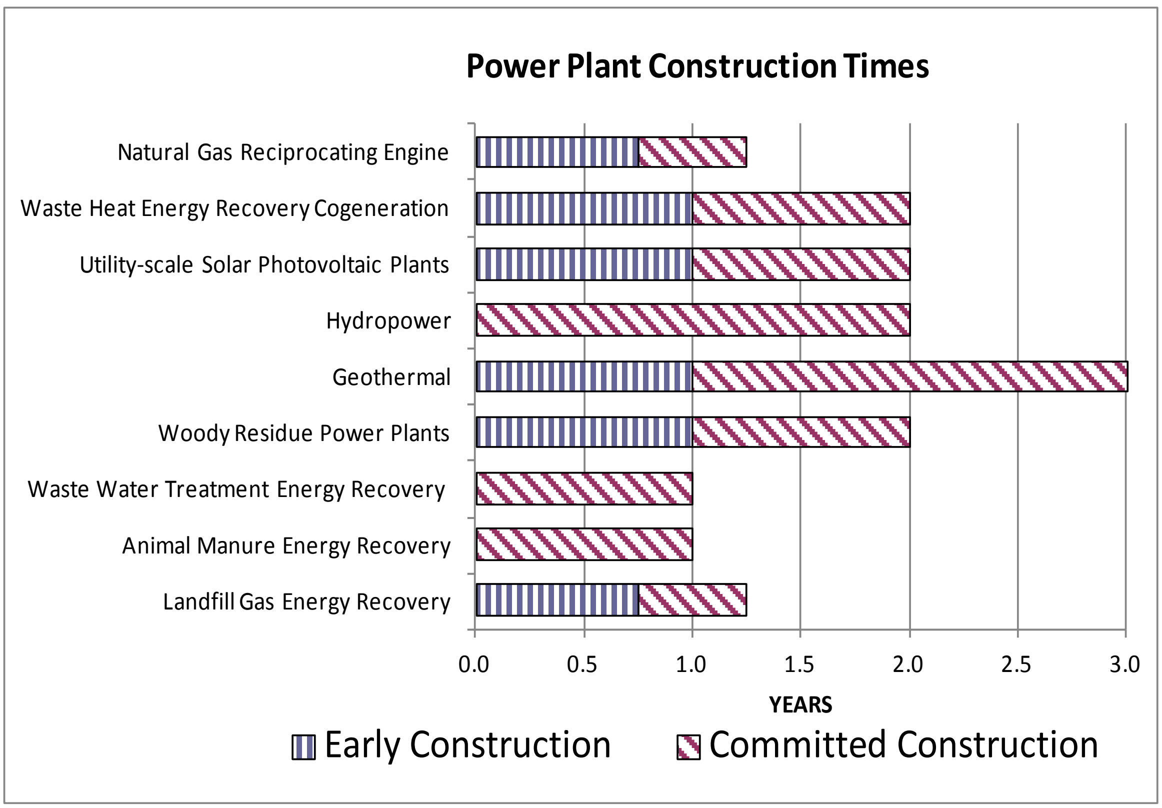


Source: Response to REC Request 2.27 to PacifiCorp

Q. Are there any other indications that construction often takes longer than one year?

A. Yes. The Northwest Power & Conservation Council's Sixth Power Plan, Appendix I provides an analysis of the wide variety of different generation resources.[40] The analysis includes an estimate of the time it takes for a generating facility to be built from development through construction. Several of the resource types took longer than a year to construct -- and that's assuming everything goes according to typical schedules. The number of years for construction of major QF resource types is displayed in Chart Three.

Chart Three



Source: Northwest Power & Conservation Council; 6th Power Plan, Appendix I - plants less than 80MW

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40 The Sixth Power Plan is available online at http://www.nwcouncil.org/media/6317/SixthPowerPlan_Appendix_I.pdf (last accessed March 17, 2013).

It is important to note that in these figures the term "Early Construction" includes such activities as major equipment orders and site preparation. These are not the type of activities I would expect a QF to typically have financing to perform prior to signing a contract and/or otherwise forming a legally enforceable obligation. The Commission is charged with encouraging renewable resource development when implementing PURPA. Requiring a project to be online within one year of creating a LEO would be another example of using a blunt instrument to solve a perceived problem that would discourage many otherwise viable projects.

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 any recommendations on the appropriate contract term?

A. The Commission should increase the term available for fixed rates from 15 years to at least 20 years. Each of the utilities proposes continuation of the current 20-year contract term with PacifiCorp recommending only the first 10 years with fixed avoided costs rather than the current 15 years. In this Oregon docket, Idaho Power proposes that the term be consistent with Idaho's 20 years, however Idaho Power does not mention the fact that in Idaho the rates are fixed for the entire 20-year term.

When a utility receives rate base treatment for one of its own generation facilities, the Company commits its ratepayers to reimbursing the Company for its costs for the depreciated life of the project. The depreciated life for most of these utility scale generation units is more than 20 years. The capital cost recovery is guaranteed through rate base treatment, and the majority of energy costs are recovered annually through base rates or an annual power cost adjustment mechanism. Unlike a QF project, those energy costs are not fixed and can change dramatically from year to year. For example, the price to supply Idaho Power's and PacifiCorp's jointly owned Bridger Coal Plant increased significantly in 2010, and that cost increase was passed on directly to ratepayers.[41] Utility customers are subject to fuel cost risks for Company-owned resources, but are protected from the volatility of natural gas and coal prices when a fixed term QF contract is signed. This is yet another example where the utilities propose that the Commission deprive QFs of similar treatment to the utility's own generation resources. It would be appropriate for the Oregon Commission to set the term for fixed avoided costs rates 20 years or more.

Q. Does this conclude your testimony on March 18, 2013?

A. Yes.

[41] *In Re Idaho Power Company Application for Authority to Implement Power Cost Adjustment Rates for Electric Service from June 1, 2010 through May 31, 2011*, IPUC Case No. IPC-E-10-12, Order No. 31093, at pp. 13-14, (2010). The increased cost was $63.7 million in 2010 to Idaho Power's Idaho customers alone.

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 201

Witness Qualification Statement of Dr. Don Reading

March 18, 2013

WITNESS QUALIFICATION STATEMENT

NAME: Don C. Reading

EMPLOYER: Ben Johnson Associates, Inc.

TITLE: Vice President and Consulting Economist

ADDRESS: 6070 Hill Road, Boise, Idaho 83703

EDUCATION: Doctor of Philosophy, Economics
Utah State University

Master of Science, Economics
University of Oregon

Bachelor of Science, Economics
Utah State University

EXPERIENCE: Dr. Reading has provided expert testimony concerning economic and regulatory issues on more than 35 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Dakota, Oregon, Texas, Utah, Wyoming, and Washington.

Dr. Reading has more than 30 years experience in the field of economics. From 1981 to 1986, Dr. Reading held positions at the Idaho Public Utilities Commission as an economist and as director of policy and administration. Prior to that, from 1968 to 1980, Dr. Reading taught economics at Middle Tennessee University, University of Hawaii at Hilo, and Idaho State University.

Relevant to the testimony in this proceeding, Dr. Reading has provided expert testimony on the issues of marginal cost, price elasticity, measured service, and avoided cost rates and contract terms. Dr. Reading's areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases are generic avoided cost rate dockets in Idaho and Oregon. Also among recent projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). Dr. Reading has also been a member of several Northwest Power Planning Council Statistical Advisory Committees and was vice chairman of the Governor's Economic Research Council in Idaho.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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

Community Renewable Energy Association

Exhibit 202

PacifiCorp's Responses to CREA's Data Requests 2.3 and 2.4

March 18, 2013

UM 1610/PacifiCorp
March 1, 2013
CREA Data Request 2.3

CREA Data Request 2.3

Reference PacifiCorp/100, Dickman/5, stating: "During the deficiency period, standard rates are based on a proxy plant that is fully dispatchable by the Company and is located in an optimum location relative to load."

(a) Please identify each gas-fired plant owned by PacifiCorp and the type of plant (simple-cycle, combined-cycle, etc.).
(b) Please provide the actual annual capacity factor of each plant identified in a. for each year since commencement of operation.
(c) For each plant, please identify its location and explain why this is an optimal location relative to load and whether PacifiCorp uses any third party transmission to move the generation from the plant to load.
(d) Please provide the capacity factor assumed for purposes of calculating the Oregon standard avoided cost rates in the proxy plant.

Response to CREA Data Request 2.3

(a) Please refer to Attachment CREA 2.3.

(b) Please refer to Attachment CREA 2.3.

(c) Plant locations are included in Attachment CREA 2.3. Explanations for the suitability of these sites relative to load are as follows:

Chehalis
As a generator interconnected to the Bonneville Power Administration (BPA) transmission system delivered to the PacifiCorp West Balancing Area Authority (PACW) Southern Oregon/Northern California and Yakima unconstrained transmission areas, the generation is delivered to an optimal location to provide flexibility and delivery options using PacifiCorp transmission and pre-established third party transmission for delivery of this generation to PacifiCorp loads. PacifiCorp uses BPA point-to-point transmission to deliver this generation to the PACW Southern Oregon/Northern California and Yakima unconstrained transmission areas.

Currant Creek
As one of PacifiCorp's fleet of generators located within the PacifiCorp East Balancing Area Authority (PACE) unconstrained transmission area, the generation resides in an optimal location to provide flexibility and delivery options using PacifiCorp transmission to PacifiCorp loads. During system normal operating conditions, no third party transmission is used for delivery of this generation to PacifiCorp loads.

Gadsby
As one of PacifiCorp's fleet of generators located within the PACE unconstrained transmission area, the generation resides in an optimal location to provide flexibility and delivery options using PacifiCorp transmission to PacifiCorp loads. During system normal operating conditions, no third party transmission is used for delivery of this generation to PacifiCorp loads.

Hermiston
As a generator interconnected to the BPA transmission system delivered to the PACW Southern Oregon/Northern California unconstrained transmission area, the generation is delivered to an optimal location to provide flexibility and delivery options using PacifiCorp transmission and pre-established third party transmission for delivery of this generation to PacifiCorp loads. PacifiCorp uses BPA point-to-point transmission to deliver this generation to the PACW Southern Oregon/Northern California unconstrained transmission area.

Lake Side
As one of PacifiCorp's fleet of generators located within the PACE unconstrained transmission area, the generation resides in an optimal location to provide flexibility and delivery options using PacifiCorp transmission to PacifiCorp loads. During system normal operating conditions no third party transmission is used for delivery of this generation to PacifiCorp loads.

(d) Please refer to the Company's response to CREA Data Request 1.4; specifically Attachment CREA 1.4. The requested information is provided in Table 8.

UM 1610/PacifiCorp
March 1, 2013
CREA Data Request 2.4

CREA Data Request 2.4

Reference PacifiCorp/200, Griswold/13, discussing load pockets.

(a) Please identify each of PacifiCorp's load pockets and provide a map depicting them.
(b) For each load pocket please provide the amount of new QF generation PacifiCorp could accept in each without acquiring third-party transmission at the present time.
(c) For each load pocket, please identify all of PacifiCorp's gas-fired generation resources (owned or contracted) located in the load pocket, the output of each plant, and the amount of third-party transmission used by PacifiCorp to move the generation from that plant to other locations.

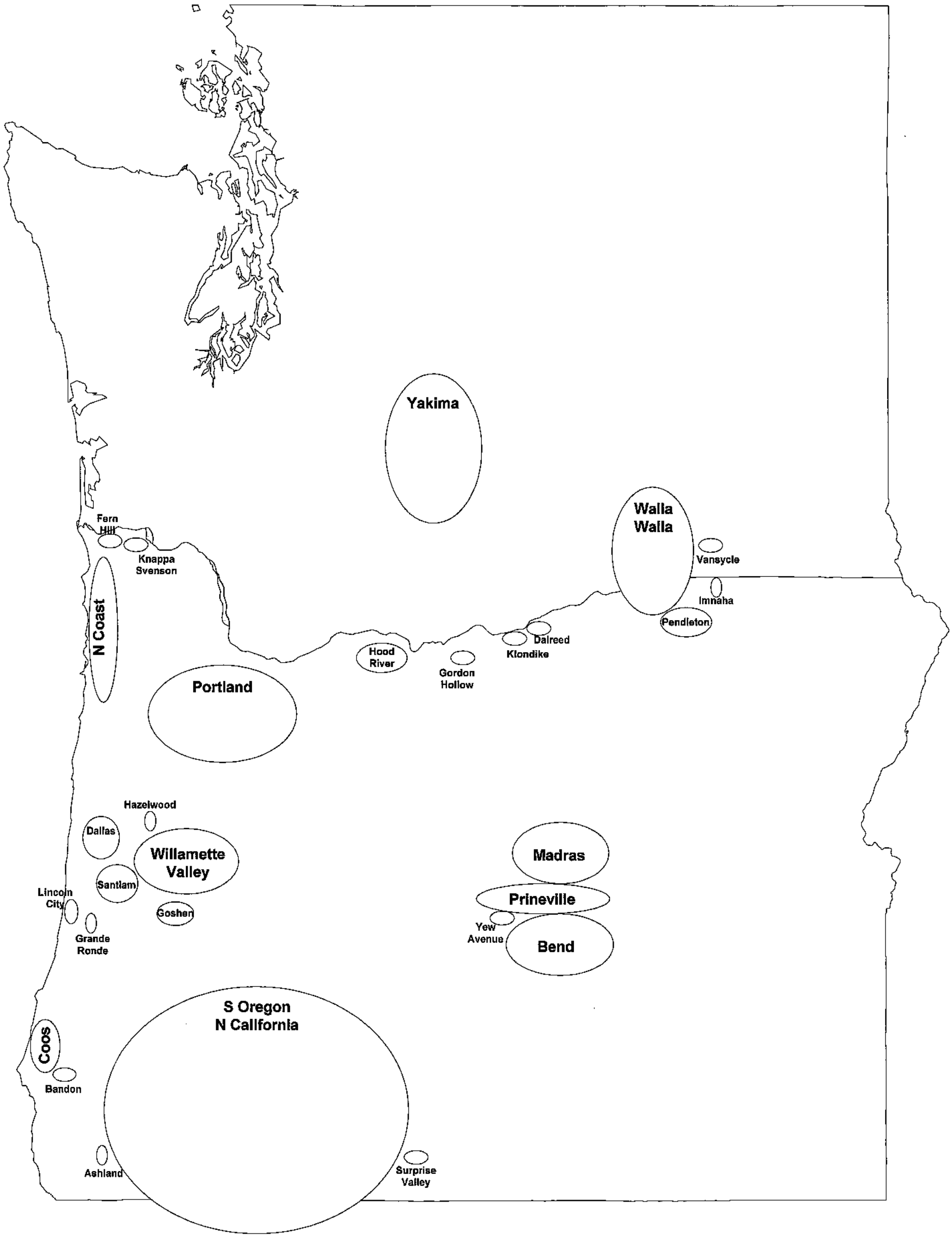
Response to CREA Data Request 2.4

(a) Please refer to Attachment CREA 2.4, which identifies and depicts the load pockets in the PacifiCorp West Balancing Authority Area (PACW).

(b) The requested information is not readily available. The amount of generation, whether a qualifying facility (QF) or non-QF, is highly dependent on the load and generation existing in each load pocket, the load forecast for each load pocket, as well as potential generation that may be under development for each load pocket. As the QF applications are received, the impacted load pockets are evaluated based on the factors described to determine transmission needs over the term of the transaction.

(c) There are no gas-fired generation resources located in the PACW load pockets. Please refer to the Company's response to CREA Data Request 2.3 for additional gas-fired plant information.

PACW – Load Pockets



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 203

PacifiCorp's FERC Form No. 1 Transmission Excerpts

March 18, 2013

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	429,811	358,628
63	(547) Fuel	367,320,902	432,620,733
64	(548) Generation Expenses	15,368,434	14,638,002
65	(549) Miscellaneous Other Power Generation Expenses	21,289,631	18,701,556
66	(550) Rents	4,253,868	3,558,679
67	TOTAL Operation (Enter Total of lines 62 thru 66)	408,662,646	469,877,598
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	2,938,948	1,240,594
71	(553) Maintenance of Generating and Electric Plant	10,918,597	8,996,404
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	4,783,736	2,196,699
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	18,641,281	12,433,697
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	427,303,927	482,311,295
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	398,261,268	380,007,678
77	(556) System Control and Load Dispatching	1,744,114	877,454
78	(557) Other Expenses	60,776,842	63,870,496
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	460,782,224	444,755,628
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,959,425,284	1,943,057,716
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,689,657	5,041,115
84	(561) Load Dispatching		650,305
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,794,035	7,847,328
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	984,307	816,883
90	(561.6) Transmission Service Studies	206,982	83,476
91	(561.7) Generation Interconnection Studies	763,228	938,904
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,647,395	2,124,825
94	(563) Overhead Lines Expenses	259,051	120,209
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	138,234,854	136,854,649
97	(566) Miscellaneous Transmission Expenses	3,568,851	4,257,862
98	(567) Rents	2,549,553	1,312,382
99	TOTAL Operation (Enter Total of lines 83 thru 98)	162,697,913	160,047,938
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,060,726	1,334,303
102	(569) Maintenance of Structures	300	395
103	(569.1) Maintenance of Computer Hardware	103,365	36,440
104	(569.2) Maintenance of Computer Software	1,119,442	1,065,683
105	(569.3) Maintenance of Communication Equipment	3,356,135	3,567,267
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	11,231,343	10,092,385
108	(571) Maintenance of Overhead Lines	22,369,881	19,173,510
109	(572) Maintenance of Underground Lines	169,531	36,881
110	(573) Maintenance of Miscellaneous Transmission Plant	1,607,372	273,467
111	TOTAL Maintenance (Total of lines 101 thru 110)	42,018,095	35,580,331
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	204,716,008	195,628,269

UM 1610

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	AD			-17			-17
2	Arizona Public Service	LFP	321,682	321,682	1,113,528			1,113,528
3	Arizona Public Service	NF	46,297	46,297	229,279			229,279
4	Arizona Public Service	OS			-236		5,843	5,607
5	Arizona Public Service	OS						
6	Arizona Public Service	SFP	46,633	46,633	156,040			156,040
7	Ashland, City of	FNS	1,808	1,808		16,893		16,893
8	Avista Corporation	FNS	56,279	59,445	228,253			228,253
9	Avista Corporation	NF	110,440	110,440	570,509			570,509
10	Basin Elect. Power Coop	NF	87,327	87,327		130,117		130,117
11	Big Horn Rural Electric	OLF					189,925	189,925
12	Bonneville Power Admin.	AD			41,832		-1,048	40,784
13	Bonneville Power Admin.	FNS			5,803,565			5,803,565
14	Bonneville Power Admin.	LFP	5,485,314	5,485,314	53,528,422			53,528,422
15	Bonneville Power Admin.	NF	533,654	533,654		2,310,228		2,310,228
16	Bonneville Power Admin.	OLF	2,571,894	2,783,711	30,771,444		110,760	30,882,204
	TOTAL		15,490,637	15,878,375	113,594,586	5,089,725	19,550,543	138,234,854

UM 1610

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
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6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin.	OS	15,131	15,131		46,676	4,419,061	4,465,737
2	Bonneville Power Admin.	OS						
3	Bonneville Power Admin.	SFP	54,376	54,376		94,616		94,616
4	CA Ind. Sys. Operator	AD				-141,583	-27,165	-168,748
5	CA Ind. Sys. Operator	OS					1,971,448	1,971,448
6	CA Ind. Sys. Operator	SFP	408,125	408,125		2,631,930		2,631,930
7	Deseret Gen & Trans	AD	1,503	1,503	11,012			11,012
8	Deseret Gen & Trans	LFP	218,291	218,291	4,209,870			4,209,870
9	Deseret Gen & Trans	NF	329,460	329,460	2,033,478			2,033,478
10	El Paso Elect. Co.	AD	-300	-300	-226			-226
11	Flathead Elect. Coop.	OS					51,696	51,696
12	Hermiston Generating Co	OS					178,852	178,852
13	Idaho Power Company	AD			-6,683		100,664	93,981
14	Idaho Power Company	FNS			8,834			8,834
15	Idaho Power Company	LFP	2,903,953	2,974,739	6,271,673			6,271,673
16	Idaho Power Company	NF	114,339	206,917	618,221			618,221
	TOTAL		15,490,637	15,878,375	113,594,586	5,089,725	19,550,543	138,234,854

UM 1610

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 204

PacifiCorp's 2011 IRP Addendum: Class 2 DSM Decrement Study Excerpts

March 18, 2013

CHAPTER 2 – CLASS 2 DSM DECREMENT STUDY

This section presents the methodology and results of the energy efficiency (Class 2 demand-side management) decrement study. For this analysis, the 2011 IRP preferred portfolio was used to calculate the decrement value ("avoided cost") of various types of Class 2 DSM resources. PacifiCorp will use these decrement values when evaluating the cost-effectiveness of current programs and potential new programs between IRP cycles.

The Class 2 DSM decrement study was enhanced for the 2011 IRP. To align with the resource costs applied for resource portfolio development using the System Optimizer capacity expansion model, cost credits were applied to the Class 2 DSM decrement values reflecting (1) a transmission and distribution (T&D) investment deferral benefit, (2) a generation capacity investment deferral benefit, and (3) a stochastic risk reduction benefit associated with clean, no-fuel resources.[7] Decrement values for two new energy efficiency load shapes were also estimated: residential water heating and "plug" loads (i.e., energy consumed by electronic devices plugged into sockets.)

Modeling Approach

To determine the Class 2 DSM decrement values, PacifiCorp defined 17 shaped Class 2 DSM resources, each at 100 megawatts at the time of peak load, and available starting in 2011 and for the duration of the 20-year IRP study period. In contrast, the valuation study for the 2008 IRP focused on 13 resources. The added resources consist of residential water heating and plug loads for both east and west control areas. Adding these new energy efficiency resources to the analysis is intended to provide a refined valuation for energy savings and further aid in developing program initiatives for such applications as showerheads, heat pump water heaters, and consumer electronics.

Consistent with prior valuation studies, PacifiCorp first determined the system production cost with and without each Class 2 DSM resources using the PaR production cost model in Monte Carlo stochastics mode. The difference in production cost (stochastic mean PVRR) for the two runs indicates the system value attributable to the DSM resource through lower spot market transaction activity and resource re-optimization with the DSM resource in the portfolio. The cost credits mentioned above are then added separately outside of the model, thereby increasing Class 2 DSM decrement values. The resource deferral benefit, as a new step for deriving the decrement values value, is described below. The PaR decrement values were determined for three CO_2 tax scenarios: zero, medium (starting at \$19/ton and escalating to \$39/ton by 2030), and low-to-very high (starting as \$12/ton and escalating to \$93/ton by 2030).

[7] Refer to Volume 1, page 147 of the 2011 IRP for a summary of the T&D investment deferral and stochastic risk reduction cost credits applied to the System Optimizer energy efficiency resource options.

Generation Resource Capacity Deferral Benefit Methodology

PacifiCorp used the System Optimizer model to determine the generation resource capacity deferral benefit. The approach is similar to the stochastic production cost difference method, except that only the fixed cost benefit of adding each 100-megawatt Class 2 DSM resource is calculated. This is accomplished by running System Optimizer with a base resource portfolio that excludes each 100-megawatt Class 2 DSM program, and then comparing the fixed portfolio costs against the cost of the same portfolio derived by System Optimizer that includes the DSM program at zero cost. The simulation period is 20 years. As a simplifying assumption, PacifiCorp applied the East "system" load shape for the generic DSM program, which has a capacity planning contribution of 93 percent and a capacity factor of 69 percent. The resource deferral fixed cost benefit is comprised of the deferred capital recovery and fixed operation and maintenance costs of a "next best alternative" resource—a combined-cycle combustion turbine (CCCT). The difference in the portfolio fixed cost represents the resource deferral benefit of the DSM program. (Note that System Optimizer's production cost benefits were not taken into account to avoid double-counting the benefit extracted from stochastic PaR model results.)

Since a 100-megawatt Class 2 DSM is not sufficiently large enough to defer a CCCT, System Optimizer was configured to allow fractional CCCT unit sizes for both the base portfolio and each of the 17 Class 2 DSM resource portfolios. Deferral of CCCT capacity can begin starting in 2015, the year after the Lake Side 2 CCCT is planned to be in service. Note that each Class 2 DSM resource can also defer front office transactions (a market resource representing a range of forward firm market purchase products).

The resource capacity deferral benefit is calculated in two steps:

1. <u>Fixed Cost Deferral Benefit Determination</u>
   Fixed cost benefits are obtained by calculating the differences in annual fixed and capital recovery costs (millions of 2010 dollars) between the base portfolio and the portfolio with the Class 2 DSM program addition. The stream of annual benefits is then converted into a net present value (NPV) using the 2011 IRP discount rate (7.17 percent).
2. <u>Levelized Value Calculation</u>
   The fixed cost resource deferral benefit value obtained from step 1 is divided by the Class 2 DSM program energy in megawatt-hours (also converted to a NPV) to yield a value in dollars per megawatt-hour-year ($/MWh-yr).

This value, along with the T&D investment deferral credit and stochastic risk reduction credit, are added to the PaR model decrement values to yield the final adjusted values.

Class 2 DSM Decrement Value Results

Table 7 reports the NPV levelized avoided costs by DSM resource and CO_2 tax scenario for 2011 through 2030, along with a breakdown of the three cost credits (capacity deferral, T&D investment deferral, and stochastic risk reduction). Tables 8, 9, and 10 report the annual nominal-dollar avoided costs, in $/MWh, for each CO_2 tax scenario. Figures 6 through 11 graphically show the avoided annual cost trends for the three CO_2 tax scenarios by east and west location, along with average annual forward market prices for the relevant location (Palo Verde (PV) for the east and Mid-Columbia (Mid-C) for the west.)

Consistent with the results for the 2008 IRP, the residential air conditioning decrements produce the highest value for both the east and west locations. The water heating (new), plug loads (new), and system load shapes provide the lowest avoided costs. Much of their end use shapes reduce loads during a greater percentage of off-peak hours than the other shapes and during all seasons, not just the summer.

Table 7 – Levelized Class 2 DSM Avoided Costs by Carbon Dioxide Tax Scenario, 20-Year Net Present Value (2011-2030)

			Total Avoided Costs by Carbon Dioxide Tax Scenario, Including all Cost Credits ($/MWh)			Cost Credit Components ($/MWh)			
Resource	Location	Load Factor	Low to Very High	Medium	None	Capacity Resource Deferral	T&D Investment Deferral	Stochastic Risk Reduction	Total Credit
Residential Cooling	East	10%	114.94	116.46	101.55	16.69	11.80	14.98	43.47
Residential Lighting	East	48%	91.17	91.71	78.49	16.69	2.35	14.98	34.02
Residential Whole House	East	35%	94.37	94.89	81.48	16.69	3.23	14.98	34.91
Commercial Cooling	East	20%	102.05	102.96	88.88	16.69	1.91	14.98	33.58
Commercial Lighting	East	48%	93.27	93.59	79.91	16.69	1.97	14.98	33.64
Water Heating	East	57%	90.57	90.95	77.72	16.69	5.83	14.98	37.50
Plug Loads	East	59%	90.16	90.49	77.40	16.69	2.33	14.98	34.00
System Load Shape	East	69%	90.31	90.72	77.53	16.69	1.62	14.98	33.29
Residential Cooling	West	7%	111.17	123.03	112.04	16.69	16.63	14.98	48.30
Residential Heating	West	25%	90.44	99.31	88.69	16.69	5.59	14.98	37.26
Residential Lighting	West	48%	88.82	97.81	88.02	16.69	2.48	14.98	34.15
Commercial Cooling	West	16%	96.04	106.31	96.43	16.69	2.60	14.98	34.27
Residential Whole House	West	49%	88.81	97.96	87.86	16.69	2.03	14.98	33.70
Commercial Lighting	West	48%	89.40	98.56	88.86	16.69	2.20	14.98	33.87
Water Heating	West	56%	87.35	96.12	86.53	16.69	7.11	14.98	38.79
Plug Loads	West	59%	87.61	96.35	86.72	16.69	2.46	14.98	34.13
System Load Shape	West	71%	87.38	96.26	86.54	16.69	1.75	14.98	33.42

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 300

Direct Testimony of Tom D. Svendsen

March 18, 2013

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Tom D. Svendsen. My business address is Herron Associates 53 Adams Loop Road, Goldendale, Washington 98620.

Q. Please describe your professional background.

A. I have attached CREA/301, which contains my qualifications and experience. To summarize here, I have worked on developing and integrating wind projects since 1980 when I was chief engineer integrating the nation's first large scale wind farm, the Bonneville Power Administration ("BPA") Mod II windfarm near Goldendale Washington. I presently sit on the executive management team for the 205 megawatt ("MW") White Creek and the 99 MW Harvest Wind Projects near Roosevelt Washington.

Q. Have you testified in previous cases before the Public Utility Commission of Oregon ("Commission" or "OPUC")?

A. No. However, I have been a party to and testified on multiple BPA rate cases.

Q. On whose behalf are you testifying?

A. I am submitting testimony on behalf of the Community Renewable Energy Association ("CREA").

Q. What is the purpose of your testimony?

A. I will provide testimony regarding the issues related to the renewable avoided cost rates based upon the costs of building and operating the next avoidable renewable resource planned by the utility. Specifically, I will 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 2: Renewable Avoided Cost Price Calculation; Issue 4: Price Adjustments for Specific QF

Characteristics (with regard to renewable avoided costs). 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"). A summary of my recommendations on the issues in my testimony is included in CREA/101, which also includes a summary of CREA's recommendations made through the testimony of Mr. Ormand Hilderbrand and Dr. Don Reading.

II. Background on Renewable Avoided Cost Pricing

Q. Have you reviewed the Commission Order No. 11-505 in docket UM 1396 addressing renewable avoided cost pricing?

A. Yes. In that order the Commission made the following determinations:

- Separate renewable avoided cost rates should be adopted for PGE and PacifiCorp.
- During periods of renewable resource sufficiency, the rate will be based on market prices. During periods of renewable resource deficiency, the rate will be based on the renewable avoided cost of the next utility scale renewable resource acquisition in that utility's Integrated Resource Plan ("IRP"). The renewable resource QF will keep all associated Renewable Energy Certificates ("RECs") during periods of renewable resource sufficiency, but will transfer those RECs to the purchasing utility during periods of renewable resource deficiency.
- The IRP Action Plan should be used to identify when a renewable resource acquisition could be avoided.

- A renewable QF should have the option of choosing among the renewable avoided cost stream and the standard avoided cost stream.

Q. Have you reviewed the compliance filings from docket UM 1396?

A. Yes. I reviewed the utilities' proposed calculations for the renewable avoided cost rates.

Q. Could you briefly summarize the utilities' proposals in UM 1396 and in this docket?

A. Both PacifiCorp and PGE identified a large wind plant as the avoided renewable resource. PacifiCorp's next renewable resource in its IRP is a Wyoming wind plant online in 2017. The assumed net capacity factor is 35%. PGE's next renewable resource in its IRP is an Oregon wind plant online in 2015. The assumed net capacity factor is 31%. Both utilities calculated the rates during the deficiency period to escalate slightly to account for inflation. Because the rates do not rely on a gas forecast, they do not escalate as dramatically as the rates calculated for the non-renewable standard QFs.

III. Issue 2. Renewable Avoided Cost Price Calculation

Issue 2. A. Should there be different avoided cost prices for different renewable generation sources? (for example different avoided cost prices for intermittent vs. base load renewables; different avoided cost prices for different technologies, such as solar, wind, geothermal, hydro, and biomass.)

Q. You stated that the utilities currently assume that the next utility scale renewable resource acquisition in PGE's and PacifiCorp's IRPs is a large wind plant, which is used to

calculate the renewable avoided cost rates. Do PGE and PacifiCorp believe that their large utility wind plants impose wind integration costs on the utility?

A. Yes. I understand that both utilities have completed wind integration studies wherein each utility concludes that their large utility wind plants do impose costs to integrate the intermittent wind output.

Q. Did the Commission make any statements on this issue in Order No. 11-505?

A. Yes. In addressing how to calculate the renewable avoided cost, the Commission declined to adopt a "recommendation to derive avoided costs for each type of renewable resource."[1] However, the Commission stated: "A wind resource is intermittent and may not fairly represent the resource value of a base load renewable resource."[2]

Q. Would a base load, renewable QF allow the utility to avoid integration costs the utility has concluded it would otherwise incur from the large, utility wind plant?

A. Yes. A base load renewable resource would not burden the utility with integrating an intermittent resource and as such should receive compensation for allowing the utility to avoid the cost of integration at the avoided utility wind plant. There is also a strong argument to be made that a small intermittent QF would impose less integration costs on the utility than the large utility wind plant, and thereby allow the utility avoid wind integration costs. Additionally, an intermittent QF that purchases wind balancing services from its transmission provider or some other third party would deliver a balanced or partially balanced renewable energy product, and thereby allow the utility avoid wind integration costs.

Q. How have the utilities proposed to address this issue in their renewable avoided cost rates?

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1 OPUC Order No. 11-505 at 5.
2 *Id.*

A. I will start with PGE's proposal. During the deficiency period, PGE proposes to increase the renewable avoided cost rates available to base load QFs by the assumed cost of wind integration at the avoided wind plant.[3] PGE also proposes to increase the renewable avoided cost rates to a lesser extent for intermittent QFs providing "partial integration" through hour-ahead and intra-hour balancing services purchased from a transmission provider such as BPA. Intermittent QFs directly connecting to the utility's system would receive no adjustment up or down to the renewable avoided cost rates, based upon the assumption that the integration costs are the same as they would be at the avoided wind plant.

Q. Do you believe PGE's proposal is reasonable?

A. As I mentioned earlier, I believe an argument could be made that all small wind QFs providing renewable output (including the RECs) enable the utility to avoid a certain amount of wind integration costs associated with a larger wind plant. Additionally, I understand PGE's proposal to include solar QFs as "intermittent" and thus be treated the same as wind QFs. Predictability is significantly higher for solar than for wind generation, decreasing scheduling errors, generation imbalance/deviation and other factors that contribute to high costs for integrating wind. This aspect of PGE's proposal is unreasonable because solar QFs impose lower integration costs on the utility and should be credited for the avoided integration costs they allow like base load QFs. Additionally, wind QFs that are able and willing to provide fully balanced deliveries should be credited with the purchasing utility's full integration costs. Balancing services available from third parties are likely to become increasingly common and may be more economical than the costs assumed to integrate output on the purchasing utility's system.

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[3] PGE/100, Macfarlane-Morton/19-20.

Aside from these issues, PGE's proposal is reasonable and appropriate to the extent that it proposes to increase the renewable avoided cost rate to account for avoided integration costs allowed by base load QFs and intermittent QFs providing balancing services.

Q. What was PacifiCorp's proposal on this topic?

A. PacifiCorp did not directly address this issue in its testimony in this case or in its compliance filing in docket UM 1396. I understand PacifiCorp's position from discovery responses and statements at the work shop to be that PacifiCorp proposes not to credit avoided wind integration costs to any QFs under the renewable avoided cost methodology. Instead, PacifiCorp proposes to only use wind integration costs as a *reduction* to the avoided cost rates available to intermittent renewable QFs during the sufficiency period and at all times for intermittent QFs taking the non-renewable rates calculated based upon a gas-fired resource. I have attached PacifiCorp's responses in discovery, which state its position on this issue at CREA/302.

Q. Is PacifiCorp's proposal reasonable?

A. No. PacifiCorp should also increase the renewable avoided cost rates during the deficiency period to account for avoided integration costs allowed by renewable QFs that impose less integration costs on the utility than the large wind plant used to calculate the renewable avoided cost rates.

Q. What is your recommendation on this issue?

A. As long as the avoided renewable resource is a large wind plant, the avoided cost rates should be adjusted upwards during the deficiency period to compensate those renewable QFs who allow the utility to avoid the costs of integrating renewable power from the avoided wind plant. I recommend PGE's proposal on this issue in its testimony in this case be adopted with the modification discussed above.

Issue 2. B. How should environmental attributes be defined for purposes of PURPA transactions?

Q. Could you explain whether there is a difference between "environmental attributes" and "renewable energy credits"?

A. Yes. Environmental attributes is a broader term that could include any greenhouse gas offsets a landfill gas project or dairy digester would create by destroying or sequestering greenhouse gases. Renewable energy credits or RECs is a narrower term only dealing with the environmental attributes of the electricity generation, generally modeled as reducing run times at existing generation or construction of other less environmentally acceptable generators.

Q. If a plant generates renewable electricity and also greenhouse gas offsets, can it separately convey the renewable electricity credits and the greenhouse gas offsets?

A. Yes, in certain situations, the renewable plant may be able to do so. In my experience, multiple companies typically come together when developing a renewable generation project that has collection, cleaning, electric generation and waste disposal components. Requiring the electric generator to provide offsets not associated with the generation of electricity is not uniformly practical. The entity that owns and operates the electric generator may be different from the entity that produces the renewable fuel, with the renewable fuel producer retaining the right to sell the greenhouse gas offsets directly associated with the fuel.

Q. Could you provide an example?

A. Yes. I have provided as CREA/303 a press release by PacifiCorp regarding a dairy digester project, which illustrates this issue well. According to PacifiCorp's press release, when PacifiCorp purchased the Chehalis gas plant, PacifiCorp agreed to provide $1.5 million in funding for greenhouse gas mitigation projects. As part of that commitment, PacifiCorp purchased 50,000 metric tons of carbon dioxide equivalent emissions reductions from an anaerobic dairy digester project near Lynden, Washington. The press release explains:

> The clean energy produced by the digester and associated renewable energy credits are being purchased by Puget Sound Energy for its voluntary green power program. These credits are separate from the greenhouse gas credits purchased by PacifiCorp.[4]

The dairy digester therefore produces and sells two separately marketable environmental attributes: (1) the RECs sold to Puget Sound Energy, and (2) the greenhouse gas offsets sold to PacifiCorp.

Q. You stated that the utilities currently assume that the next utility scale renewable resource acquisition in PGE's and PacifiCorp's IRPs is a wind plant, which is used to calculate the renewable avoided cost rates. Does a large utility wind plant generate greenhouse gas offsets?

A. Based upon my experience, wind plants do not create any marketable greenhouse gas offsets. A wind plant does not directly reduce the methane or other carbon-based emissions in a manner that is marketable. The California greenhouse gas offset market is currently one of the primary markets for greenhouse gas offsets. The California Air Resources Board has adopted four types of resources that produce marketable offsets: U.S. Forest Projects, Urban Forest

[4] CREA/303, Svendsen/1.

Projects, Livestock Projects, and Ozone Depleting Substances Projects.[5] A wind plant falls within none of these categories.

Q. Do the utilities need to obtain the greenhouse gas offsets from a dairy digester or landfill gas plant in order to use the RECs from that plant to comply with Oregon's RPS?

A. I am not an attorney and will not provide a legal conclusion on whether the utilities need greenhouse gas offsets in order to meet Oregon's RPS. However, it is my understanding that Oregon RECs are monitored and tracked by WREGIS. The WREGIS Operating Rules provide the mechanism to obtain a Certificate for "Renewable and Environmental Attributes" as including avoided emissions.[6]

However, WREGIS explains in a footnote in the definition:

> The avoided emissions referred to here are the emissions avoided by the generation of electricity by the Generating Unit, and therefore *do not include the reduction in greenhouse gases (GHGs) associated with the reduction of solid waste or treatment benefits created by the utilization of biomass or biogas fuels*. Avoided emissions may or may not have any value for complying with any local, state, provincial or federal GHG regulatory program. Although avoided emissions are included in the definition of a WREGIS Certificate, this definition does not create any right to use those avoided emissions to comply with any GHG regulatory program.[7]

WREGIS expressly excludes greenhouse gas offsets from its definition of renewable attributes.

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5 California's program is comprehensively described online at the following link: http://www.arb.ca.gov/cc/capandtrade/guidance/chapter6.pdf , (last accessed March 17, 2013).

6 WREGIS's Operating Rules are available online at: http://www.wecc.biz/WREGIS/Documents/WREGIS%20Operating%20Rules.pdf (last accessed March 17, 2013).

7 *Id.* at p. 4 n.2.

Q. Did the Commission declare in Order No. 11-505 that the renewable QF should provide to the utility all environmental attributes including greenhouse gas offsets?

A. No. The Commission stated: "The renewable resource QF will keep all associated <u>Renewable</u> <u>Energy</u> <u>Certificates</u> <u>(RECs)</u> during periods of renewable resource sufficiency, but will transfer those <u>RECs</u> to the purchasing utility during periods of renewable resource deficiency." [8] The Commission did not state that the renewable QF must transfer to the utility any non-energy attributes other than the RECs needed to meet Oregon's RPS requirements.

Q. What have PGE and PacifiCorp proposed in UM 1610?

A. PacifiCorp appears to propose that renewable QF contracts require the renewable QF convey to the purchasing utility not only the RECs necessary for RPS compliance, but also all greenhouse gas offsets. PacifiCorp's witness recommended: "Therefore, during the period of renewable resource deficiency, when the QF transfers the facility's RECs to the utility, the Environmental Attributes, including avoided greenhouse gas emissions, are similarly transferred."[9] PGE did not directly respond to the question, and instead provided a link to the Western Systems Power Pool Service Schedule R, addressing REC transactions.[10] PGE did not provide this document or any specific way of addressing this issue in renewable rate contracts.

Q. What is your recommendation on how environmental attributes should be defined in Oregon's renewable QF contracts?

A. The premise behind the renewable avoided cost rate stream is that the QF will convey the energy, capacity, and renewable attributes needed by the utility for compliance with Oregon's RPS. To qualify for the renewable avoided cost, the QF should generate and convey

[8] OPUC Order No. 11-505 at 2 (emphasis added).
[9] PacifiCorp/200, Griswold/9;
[10] PGE/100, Macfarlane-Morton/15.

electricity and RECs that meet the requirements of "qualifying electricity" set forth in the Oregon RPS.[11] Because the avoided renewable resource is currently a large wind plant, the renewable QF should retain all environmental attributes that would not be created by the avoided wind plant, including greenhouse gas offsets. If the utilities wish to also obtain greenhouse gas offsets from QFs that may produce them, the utilities could develop a separate renewable rate stream based on a renewable plant that produces greenhouse gas offsets, such as dairy digester plant or landfill gas plant designed to reduce methane emissions. The utilities could do so at the present time, or at any time in the future that state or federal law may require the utilities to obtain such greenhouse gas offsets.

Issue 2. C. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?

Q. Does CREA have a position on this issue?

A. Yes. CREA believes that no amendment of the rule is necessary because for renewable QFs with PacifiCorp and PGE the PPA can assign ownership of the renewable energy credits to the utility during the deficiency period.

Q. Idaho Power proposed that the Commission should assign ownership of renewable energy credits to the utility even in the standard, non-reneweable avoided cost rate contracts. Do you agree?

A. No. CREA disagrees with Idaho Power's position that the utility should own the RECs under a non-renewable avoided cost rate. The OPUC has addressed this issue several years

11 ORS 469A.010, 469A.020, and 469A.025.

ago.[12] If the utility is paying a standard, non-renewable rate for "brown power," the utility should not be entitled to claim any renewable attributes of that power. Idaho Power does not propose to pay for the costs associated with renewable generation, and should not be entitled to the RECs. However, this is largely a legal issue that CREA will address in legal briefing.

IV. Issue 4. Price Adjustments for Specific QF Characteristics

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

Q. Do you have anything to add on this issue?

A. No. I addressed this issue above for renewable avoided cost rate calculations. Dr. Don Reading addresses this issue for CREA with regard to the utility's proposal to reduce the standard non-renewable avoided cost rates to account for wind integration.

Issue 4. B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?

Q. Did the Commission make any comments regarding transmission costs of the avoided renewable resource in Order No. 11-505?

A. Yes. The Commission declined to use a generic renewable avoided cost proxy that might apply to both PGE and PacifiCorp with generic inputs. In doing so, the Commission noted, "Differences in capacity, capacity factors and transmission costs--due primarily to differences in

[12] OPUC Order No. 05-1229 at 8.

locations--would not be captured in a proxy model, so that the proxy would not provide an accurate measure of a utility's true avoided cost."[13] It appears that the Commission acknowledged that capacity factor and transmission costs could change based upon a change to the particular utility's plans in its IRP. Transmission is a significant cost for wind plants. Part of the reason why transmission is so expensive for wind projects is because wind projects have a lower capacity factor than many other resources. A wind plant will need a transmission reservation of its full nameplate capacity. When modeling the cost for the wind plant on a $/MWh basis, the transmission cost will be much higher than for a project with a larger capacity factor, which enables the project to spread the transmission costs over more energy production.

Q. In the renewable QF PPAs included in the utilities' UM 1396 compliance filings, who is responsible for paying for third party transmission to deliver the QF output to the purchasing utilities' electrical system?

A. The QF is responsible for all costs to deliver to the utilities' system. I understand that as a general policy, the Oregon Commission requires small QFs to pay for all interconnection and transmission costs to the utility's system and even any network upgrades needed on the utility's system to get the output to load.

Q. Is this always the case in renewable PPAs outside of the PURPA context?

A. Not necessarily. Sometimes the generator will sell the output at the busbar and the purchasing utility will be responsible for the transmission costs to its system and to its load. Additionally, if the utility builds and owns the wind resource itself, then the utility must pay for the third-party transmission and any costs to upgrade the utility's own system to get the output to load.

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

Q. Could you discuss how PacifiCorp has addressed this issue in its renewable avoided cost rate calculations and any changes that might be necessary?

A. PacifiCorp assumed it would build the next wind plant in Wyoming, where PacifiCorp believes the capacity factor would be quite favorable at 35%, but PacifiCorp also included no costs for transmission from the Wyoming wind plant to PacifiCorp load. These assumptions are not reasonable. PacifiCorp needs to include a transmission cost adder if they use a Wyoming wind plant for their proxy renewable resource. The costs to transmit output from Wyoming to the Pacific Northwest are very large. I have provided Table I-24 of the Sixth Northwest Power Plan as CREA/204. This table includes reasonable cost assumptions for wind plants, including costs of transmission from various locations to Oregon locations. It shows a $72/MWh adder for transmission delivery from a Wyoming wind project to the Northwest load centers.[14] Additionally, PacifiCorp's IRP specifically discusses incremental transmission costs from different generation "bubbles" based upon upgrades to PacifiCorp's system and plans to connect PacifiCorp's east and west control areas and renewable energy zones through its "Energy Gateway" proposal.[15] These costs are significant, and it is not reasonable to assume that PacifiCorp can build wind plants in Wyoming without any incremental transmission costs.

Q. How did PGE address transmission costs in its renewable avoided cost rates?

A. Based upon the work papers provided, PGE included transmission costs in its calculation. PGE's avoided wind plant from its IRP is in Oregon and would use BPA transmission to wheel the output to PGE's load center. However, PGE's calculations for transmission in their renewable avoided cost model does not follow their transmission assumptions in their 2009 IRP.

[14] CREA/304, Svendsen/1.
[15] PacifiCorp's 2011 IRP, Volume 1, at p. 128, available online at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf (last accessed March 17, 2013).

I understand that PGE used these assumptions from the IRP for purposes of evaluating bids in its ongoing requests for proposals.[16] The assumptions in the IRP and used for modeling in the request for proposals ("RFP") for larger resources included reasonable assumptions for increased costs of BPA transmission rates over the life of a wind plant. If one uses these transmission rates from the IRP and properly adjusts to account for the low capacity factor of a wind plant, the cost for transmission would be up to 67% higher than reported in PGE's work papers for the renewable avoided costs rates. PGE should be consistent and use the transmission rates per the IRP and in the RFPs.

Q. What is your recommendation on how transmission costs should be treated?

A. All renewable QFs will allow utilities to avoid the costs of third-party transmission associated with the avoided renewable plant. QFs should be compensated for that significant and demonstrable avoided cost as part of the renewable avoided cost rate calculation. CREA's witness Dr. Don Reading will also address this issue with regard to QF contracts based on the avoided costs of a conventional power plant, which is currently a gas-fired plant.

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

Q. Do you have any comments on this issue?

A. Dr. Don Reading addresses the bulk of this issue for CREA. His comments and recommendations should also apply to rates calculated under the renewable avoided cost mechanism. However, I will add comments specific to renewable avoided cost rate calculations that with regard to the sixth factor, which regards consideration of the individual and aggregate

[16] PGE's 2009 IRP, at p. 194, available online at http://www.portlandgeneral.com/our_company/news_issues/current_issues/energy_strategy/docs/irp_nov2009.pdf (last accessed March 17, 2013)..

value of energy and capacity from qualifying facilities on the electric utility's system.[17] At a minimum, I believe that this factor should require the utilities to actually include proper assumptions for the avoided renewable resource.

Q. Do you have any comments in that regard on any other elements of the calculation of the renewable avoided cost rates in the UM 1396 compliance filings?

A. Yes. Several of the assumptions appear to be unrealistic. For PacifiCorp, the calculated capital cost is $62.42/MWh based upon a capacity factor listed at 35%. However, capacity factors have been declining because of Balancing Authority curtailments. For the wind projects I am associated with these curtailments have decreased the capacity factor by just over 2%. PGE uses a 31% capacity factor. This too may not reflect the full effect of transmission curtailments, as it was modeled prior to the most recent BPA curtailment protocols. A reduction in capacity factor or 2% results in an increase in costs of approximately $6.85/MWh for PGE and an increase in cost of approximately $5.62/MWh for PacifiCorp.

Additionally, PacifiCorp's calculations are based upon receiving a Production Tax Credit not presently available for a plant that will be online in 2017, like PacifiCorp's proposed plant. Similarly, PGE's work papers note "a. Base case (PTC and BETC extended at current conditions)." It is not appropriate to include these credits to reduce the avoided cost rates because they are unlikely to be renewed and thus work as a highly speculative reduction to the avoided cost rates. This is particularly the case for PacifiCorp because its wind plant would not be online until 2017, a date far beyond the current availability of the tax credits.

Q. Were there any other assumptions that were questionable?

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[17] 18 CFR 292.304(e)(2)(vi).

A. PacifiCorp's calculated operations and maintenance ("O&M") cost is $10.41/MWh in 2010 dollars ($11.44 in 2015). PGE modeled $11.09/MWh in 2015. These appear to be reasonable assumptions for those early years of the contract while the warranties are in place. However, neither utility included a bump up in costs to properly include the increased costs after the initial warranty period expires. This has not traditionally been modeled effectively at the beginning of a project. Once the warranty expires the owner must pay not only for O&M but also for all breakdowns and repairs, which would include such things as main bearing failures, gear box failures and a multitude of other replacements and repairs not covered under an O&M contract. Using a conservative cost assumption for securing an extended warranty as a proxy for the cost of break downs and repairs, I believe that the cost of break downs and repairs after the initial warranty period would cost approximately $5/MWh in addition to the standard O&M assumption included in the utilities' renewable rate calculations. Both PacifiCorp and PGE should address how they will account for breakdowns and repairs once their initial warrantee has expired.

Q. Do you have any concluding comments?

A. Yes. As my testimony on the proposed rates of the utilities demonstrates, the actual calculation of the rates must be scrutinized to ensure it includes all of the utilities' avoided costs for a renewable resource. In Order No. 11-505, the Commission stated: "We agree with Staff, ICNU, ODOE, and CREA, that implementation of these policies requires an evidentiary record to derive utility-specific avoided cost rates for renewable resources. As CREA notes, the IRP process, while complex, is not a litigated proceeding in which a utility's estimates of the costs of its resources are subjected to extensive discovery."[18] The Commission should reaffirm that the

[18] OPUC Order No. 11-505 at 11.

utilities' calculation of their renewable avoided costs should be always be subject to discovery and comment from interested parties, rather than being developed in an IRP process. These assumptions should be included in a transparent manner with the filing of the renewable avoided cost rates, so that interested parties can quickly and easily recommend changes.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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

Community Renewable Energy Association

Exhibit 301

Witness Qualification Statement of Tom D. Svendsen

March 18, 2013

WITNESS QUALIFICATION STATEMENT

NAME: Tom D. Svendsen P.E.

ADDRESS: Herron Associates 53 Adams Loop Road, Goldendale, Washington 98620.

EDUCATION: Bachelor of Science – Electrical Engineering (Power Option) University of Washington 1976

EXPERIENCE: Mr. Svendsen is a registered professional electrical engineer with more than 35 years of electric utility experience. Mr. Svendsen's experience covers a wide array of utility topics, such as transmission, power generation, utility operations, power purchase contracts, planning, rates, and bond sales. His power projects include hydroelectric, landfill gas, wind, and pumped storage development, as well as numerous transmission interconnections including laying the groundwork for over 1,400 MW of wind generation. Mr. Svendsen has specialized in renewable generation, building, operating and developing generation projects and the associated policies and legislation surrounding such projects.

From 2009 to present, Mr. Svendsen has been the owner of Columbia Gorge Energy Consultants, representing various clients in their energy needs including: Off-takers representative for the 205 MW White Creek Project; Technical Advisor for Community Renewable Energy Association; and Representation of wind developers, biomass projects and other renewable energy projects in Power Purchase Contracts, BPA interfaces, utility negotiations and other energy transactions.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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

Community Renewable Energy Association

Exhibit 302

PacifiCorp's Response to CREA Data Requests 1.7 and 1.8

March 18, 2013

UM 1610/PacifiCorp
November 29, 2012
CREA Data Request 1.7

CREA Data Request 1.7

Reference PacifiCorp's UM 1396 Compliance Filing, PAC/100, Brown/6, lines 13-15, referencing the "300 MW Wyoming wind resource" studied in the preferred portfolio of the 2011 IRP. Please specifically identify the assumed costs ($/MWh) and basis for the assumptions for the following factors:

(a) Point-to-Point Transmission. Please also identify the transmission provider, the form of scheduling and delivery assumed, and the ancillary services assumed in the cost assumption.
(b) Incremental transmission costs other than Point-to-Point Transmission. Please explain assumptions made.
(c) State and federal tax credits or grants utilized.
(d) Wind Integration Costs. Please include identification of whether the IRP wind plant would pay BPA or another third party for partial or full integration, or whether the IRP wind plant would be fully or partially integrated by PacifiCorp.

Response to CREA Data Request 1.7

(a) Please refer to the Company's response to CREA Data Request 1.6.

(b) Please refer to the Company's response to CREA Data Request 1.6. No incremental transmission integration costs are assumed.

(c) The benefit of production tax credits (PTCs) was assumed for wind resources in the 2011 integrated resource plan (IRP) preferred portfolio.

(d) Please refer to the Company's response to CREA Data Request 1.6. A Wyoming wind resource would not be interconnected to the Bonneville Power Administration (BPA). The wind integration costs assumed reflect wind integration costs on PacifiCorp's system.

UM 1610/PacifiCorp
November 29, 2012
CREA Data Request 1.8

CREA Data Request 1.8

Reference PacifiCorp's UM 1396 Compliance Filing, PAC/100, Brown/6, lines 13-15, referencing the "300 MW Wyoming wind resource" studied in the preferred portfolio of the 2011 IRP. Please explain whether PacifiCorp's IRP wind plant would impose the costs of wind integration on PacifiCorp's customers. Please explain why or why not.

Response to CREA Data Request 1.8

Yes. Please refer to page 129 of the PacifiCorp's 2011 Integrated Resource Plan (IRP) for an explanation of wind integration costs modeled in the IRP.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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

Community Renewable Energy Association

Exhibit 303

PacifiCorp's Press Release on RECs and Greenhouse Gas Offsets

March 18, 2013

CREA/303
Svendsen/1

PACIFICORP

Got Methane?

July 25, 2011

More than 2,000 dairy cows in northwest Washington will be prime mooo-vers in helping a western electric utility learn more about destroying greenhouse gas emissions that contribute to climate change.

PacifiCorp, which serves 1.7 million customers as Pacific Power and Rocky Mountain Power, recently signed a contract with The Climate Trust to purchase 50,000 metric tons (tonnes) of carbon dioxide equivalent, verified emission reductions from a livestock anaerobic digester project near Lynden, Wash. This project, operated by Farm Power, captures and destroys methane from manure management systems at MJD Farms dairy operations. Manure from three separate barns is pumped three-quarters of a mile to an anaerobic digester, which burns the methane to operate a turbine engine that creates electricity.

"Preventing methane from entering the atmosphere actually can have more environmental benefits than reducing carbon dioxide emissions," said Mark Miller, PacifiCorp plant manager in Chehalis, Wash. That is because methane has a global warming potential 23 times greater than carbon dioxide, according to the Intergovernmental Panel on Climate Change. The 50,000 tonnes is equivalent to greenhouse gas emissions from more than 9,800 cars driven for one year.

PacifiCorp's participation in this project results from the company's 2008 purchase of the 520-megawatt Chehalis natural gas-fueled generating plant in western Washington. The Chehalis Generating Facility began operations in 2003, before the Washington Legislature passed requirements that now mandate that generating facilities mitigate a portion of their greenhouse gas emissions.

As part of PacifiCorp's purchase of the Chehalis plant, the company agreed to provide $1.5 million in funding for greenhouse gas mitigation projects, including reimbursement of state agency staff for their time reviewing and approving proposals. The Lynden methane reduction project represents one key component of this mitigation portfolio.

The Climate Trust is responsible for managing carbon funds; identifying and acquiring emission reduction projects; overseeing monitoring, verification and delivery of carbon credits, and ensuring all projects conform to leading industry standards such as the Climate Action Reserve. The Climate Trust will transfer the Verified Emission Reductions to PacifiCorp.

"This project illustrates that investment in innovation such as digester projects can pave the way to new sources of renewable energy and economic stimulus for the local communities, in addition to helping protect the climate," said Sheldon Zakreski, senior program manager for The Climate Trust.

In addition to the greenhouse gas credits being purchased by PacifiCorp, other environmental and economic benefits of the methane reduction project include:

- The clean energy produced by the digester and associated renewable energy credits are being purchased by Puget Sound Energy for its voluntary green power program. These credits are separate from the greenhouse gas credits purchased by PacifiCorp.
- Hot water, a byproduct of burning the methane, is used to help heat a nearby greenhouse.
- The improved manure management system improves local air and water quality.
- Farmers can use the other digester byproducts including a nutrient-rich liquid fertilizer and pathogen-free organic matter that can be used as cow bedding.

About The Climate Trust
The Climate Trust is a 501(c)(3) nonprofit organization headquartered in Portland, Oregon. The Climate Trust's mission is to provide expertise, financing and inspiration to accelerate innovative climate solutions

that endure. In order to arrest the rise in greenhouse gas emissions and to avoid the most dangerous impacts of climate change, The Climate Trust pioneers ways to accelerate project, financing and policy implementation as a trustee of environmental assets in the renewable energy, energy efficiency, agricultural, forestry and transportation sectors.

About PacifiCorp
PacifiCorp is one of the lowest-cost electricity producers in the United States, serving more than 1.7 million customers in the West. PacifiCorp operates as Pacific Power in Oregon, Washington and California, and as Rocky Mountain Power in Utah, Wyoming and Idaho. With a generating capability of more than 10,620 megawatts from coal, hydro, gas-fired combustion turbines and renewable wind and geothermal power, the company works to meet growing energy demand while protecting and enhancing the environment.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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

Community Renewable Energy Association

Exhibit 304

Northwest Power and Conservation Council Sixth Power Plan
Wind Plant Inputs

March 18, 2013

Table I-24: Levelized cost of Wind Power Plants

Case	Service Year	Plant Busbar ($/MWh)	Ancillary Services and Integration ($/MWh)	Transmission and Losses ($/MWh)	Emissions ($/MWh)	Total ($/MWh)
Wind (MT Local)	2010	$77.05	$10.62	$6.76	$0.00	**$94**
	2015	$71.20	$11.33	$6.75	$0.00	**$89**
	2020	$69.47	$11.70	$6.74	$0.00	**$88**
	2025	$67.81	$11.83	$6.72	$0.00	**$86**
	2030	$66.20	$11.89	$6.71	$0.00	**$85**
Wind (OR/WA Local)	2010	$93.24	$10.62	$8.02	$0.00	**$112**
	2015	$84.18	$11.33	$7.97	$0.00	**$103**
	2020	$82.13	$11.70	$7.95	$0.00	**$102**
	2025	$80.15	$11.83	$7.93	$0.00	**$100**
	2030	$78.24	$11.89	$7.92	$0.00	**$98**
Wind (S. ID Local)	2010	$100.08	$10.62	$8.56	$0.00	**$119**
	2015	$89.66	$11.33	$8.49	$0.00	**$109**
	2020	$87.47	$11.70	$8.46	$0.00	**$108**
	2025	$85.36	$11.83	$8.44	$0.00	**$106**
	2030	$83.32	$11.89	$8.43	$0.00	**$104**
Wind (MT> S. ID)	2010	n/av	n/av	n/av	n/av	**n/av**
	2015	$71.20	$10.84	$34.17	$0.00	**$116**
	2020	$69.47	$11.18	$34.17	$0.00	**$115**
	2025	$67.81	$11.31	$34.16	$0.00	**$113**
	2030	$66.20	$11.37	$34.25	$0.00	**$112**
Wind (MT > OR/WA via CTS upgrade)	2010	n/av	n/av	n/av	n/av	n/av
	2015	$71.20	$10.84	$46.46	$0.00	**$128**
	2020	$69.47	$11.18	$46.37	$0.00	**$127**
	2025	$67.81	$11.31	$46.28	$0.00	**$125**
	2030	$66.20	$11.37	$46.29	$0.00	**$124**
Wind (WY> S. ID)	2010	n/av	n/av	n/av	n/av	**n/av**
	2015	$71.20	$10.84	$38.98	$0.00	**$121**
	2020	$69.47	$11.18	$38.98	$0.00	**$120**
	2025	$67.81	$11.31	$38.98	$0.00	**$118**
	2030	$66.20	$11.37	$39.09	$0.00	**$117**
Wind (AB > OR/WA)	2010	n/av	n/av	n/av	n/av	**n/av**
	2015	$71.20	$10.84	$56.17	$0.00	**$138**
	2020	$69.47	$11.18	$56.21	$0.00	**$137**
	2025	$67.81	$11.31	$56.24	$0.00	**$135**
	2030	$66.20	$11.37	$56.44	$0.00	**$134**
Wind (MT > OR/WA via S. ID)	2010	n/av	n/av	n/av	n/av	**n/av**
	2015	$71.20	$10.84	$64.85	$0.00	**$147**
	2020	$69.47	$11.18	$64.87	$0.00	**$146**
	2025	$67.81	$11.31	$64.88	$0.00	**$144**
	2030	$66.20	$11.37	$65.08	$0.00	**$143**
Wind WY > OR/WA)	2010	n/av	n/av	n/av	n/av	n/av
	2015	$71.20	$10.84	$72.11	$0.00	**$154**
	2020	$69.47	$11.18	$72.13	$0.00	**$153**
	2025	$67.81	$11.31	$72.15	$0.00	**$151**
	2030	$66.20	$11.37	$72.37	$0.00	**$150**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 14th day of March, 2013, a true and correct copy of the within and foregoing **DIRECT TESTIMONY OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION** was served as shown to:
(electronic service of redacted materials, paper service of confidential material)

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By [signature]
Gregory M Adams