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March 18, 2013

Via Electronic and FedEx

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of Public Utility Commission of Oregon Investigation Into Qualifying Facility Contracting and Pricing
Docket No. UM 1610

Dear Filing Center:

Enclosed please find the original and five (5) copies of the Response Testimony and Exhibits of Donald Schoenbeck; five (5) copies of the Response Testimony and Exhibits of Jeremiah Camarata and Edson Pugh; and five (5) copies of the Response Testimony and Exhibits of John Lowe on behalf of the Renewable Energy Coalition in the above-referenced docket.

Please also find one (1) CD containing the testimony and exhibits; and three (3) CDs containing the workpapers of Donald Schoenbeck. All backup workpapers are also being provided concurrently via e-mail to Staff, PacifiCorp, PGE, and Idaho Power.

Thank you for your assistance, and please do not hesitate to contact our office if you have any additional questions.

Sincerely,

Karen Zolka

Karen A. Zolka

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Testimony and Exhibits on behalf of the Renewable Energy Coalition upon the parties, on the service list, via electronic mail, and via U.S. Mail where paper service has not been waived.

Dated at Portland, Oregon, this 18th day of March, 2013.

Sincerely,

Karen Zolka

Karen A. Zolka

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
	)
Investigation Into Qualifying Facility Contracting and Pricing	)

RESPONSE TESTIMONY OF

JOHN LOWE

ON BEHALF OF

THE RENEWABLE ENERGY COALITION

March 18, 2013

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Lowe. I am the director of the Renewable Energy Coalition (the "Coalition"). My business address is 12040 SW Tremont Street, Portland, Oregon 97225.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I was employed by PacifiCorp for thirty-one years, most of which was spent implementing the Public Utility Regulatory Policies Act ("PURPA") regulations throughout the utility's multi-state service territory. My responsibilities included all contractual matters and supervision of others related to both power purchases and interconnection. Since 2006, I have been directing and managing the activities of the Coalition as well as providing consulting services to individual members related to both power purchases and interconnections. A further description of my educational background and work experience can be found in Exhibit Coalition/101 in this proceeding.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Coalition.

Q. PLEASE DESCRIBE THE COALITION, ITS MEMBERS AND ITS OVERALL INTEREST IN THIS PROCEEDING.

A. The Coalition is comprised of thirty-two members who own and operate non-intermittent qualifying facilities ("QFs") in the five states of Oregon, Idaho, Washington, Utah, and Wyoming. Since some members own and operate more than one project, there are forty-five projects currently represented, all except five are small hydroelectric projects less than 7 megawatts ("MW") and nearly all existing projects currently selling to PacifiCorp or Idaho Power Company. Several types of entities are members of the Coalition, including cities, irrigation districts, water districts, Oregon corporations, and individuals. The Coalition's broad interests in this proceeding are two-fold: 1) addressing many of the PURPA implementation issues raised by the Coalition in its petition to the Oregon Public Utility Commission ("OPUC" or the "Commission") in 2009, referenced as UM 1457; and 2) assuring that the unique interests of existing projects are considered.

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. Generally, my testimony is focused upon the policies and processes involved in PURPA implementation related to power purchase agreements including pricing and other terms. This includes: 1) the size threshold for application of standard or form power purchase agreements and published avoided cost prices; 2) the timing and manner in which avoided cost prices are updated; 3) the term for fixed prices for both new and existing projects; 4) the continuance of payments for capacity for existing projects entering into replacement power purchase agreements during resource sufficiency periods and the levelization of prices; 5) establishing a legally enforceable obligation in the power purchase agreement process; 6) ownership of environmental attributes; and 7) whether avoided cost pricing methodology needs to be consistent among the three utilities.

Q. ARE THERE ANY OTHER WITNESSES TESTIFYING ON BEHALF OF THE COALITION?

A. Yes. Donald Schoenbeck, Jeremiah Camarata, and Edson Pugh are also providing testimony on behalf of the Coalition. Mr. Schoenbeck is testifying on issues related to avoided cost prices, the size threshold and other issues. Mr. Camarata is the District Manager for Farmers Irrigation District, and Mr. Pugh is the General Manager for Deschutes Valley Water District, both which are a Coalition members and own and operate small hydroelectric QFs. Messrs. Camarata and Pugh address the impact of changing the size threshold and contract duration on existing hydro QFs in Oregon.

Q. CAN YOU DESCRIBE OREGON'S CURRENT PURPA POLICY AND WHAT ASPECTS ARE WORKING FOR QFS?

A. The implementation of PURPA in Oregon has significantly improved since its beginnings in the early 1980s, but there have been a few significant swings to the negative side over the years. The environment for renewable energy projects has vastly improved following the Commission's orders in UM 1129 relating to power purchase agreements and AR 521 related to small generator interconnection rules. These proceedings led to critically important improvements for renewable development, including raising the size threshold to 10 MW for standard contracts and published prices, standard processes for entering into agreements, and a two year cycle for updating avoided costs filings.

Q. WHAT ASPECTS OF OREGON'S PURPA POLICY ARE CAUSING DIFFICULTIES FOR QFS AND SHOULD BE CHANGED IN THIS PROCEEDING.

A. Most of the key issues have been decided through previous dockets. Wholesale changes are unnecessary and would have harmful results. The Commission should reaffirm its previous conclusion that there are important issues besides perfection in avoided cost rates. The Commission should also recognize that there is a critical nexus between key points in PURPA's implementation, including how and when avoided cost prices are updated, and when a legally enforceable obligation is created. It has been demonstrated over the past several years that, when avoided cost prices drop, the existing rules and processes are applied inconsistently, often to the disadvantage of QFs.

The Commission should also require the utilities to make capacity payments to existing projects that are entering into replacement agreements during a resource sufficiency period. Mr. Schoenbeck addresses this issue in his testimony in greater detail, but the failure to make capacity payments to existing QFs results in a inappropriate disincentive to the continued operation of such projects.

Q. DO YOU HAVE ANY COMMENTS ON THE OVERALL APPROACH OR TONE OF THE UTILITIES' TESTIMONY?

A. Yes. With a few exceptions, the utilities' proposed changes will have a significant cooling effect upon the development of new projects. In addition, for existing projects, the proposals to reduce the size threshold for standard prices and contracts to 100 kilowatts ("kw") and limiting the contract term to five years could result in some projects ceasing to operate. In general, it appears the goal of the utilities is to minimize their exposure to power purchase expenses from QFs rather than focus on key issues that created the impetus for this proceeding. Instead of making corrections or improvements to the underlying policies and procedures, it appears the utilities are seeking wholesale re-design of PURPA's implementation. This goes against the grain of the Commission's previous actions and decisions.

Q. IS THE COALITION ADDRESSING ALL OF ITS PURPA CONCERNS AT THIS TIME?

A. No. First, the Coalition is only addressing some of the issues in Phase I. Issues reserved for Phase II will be addressed in future testimony in this proceeding. In addition, the Coalition has other concerns with the interconnection process which are not currently part of Phase I or II of this proceeding. These include, but by no means limited to, timing and process for progress payments, unnecessary unilateral expensive requirements, inflated and unreliable estimates, excessive utility management charges, lack of specific cost details, and inability to provide full and proper accounting of costs. These are important issues that should be addressed in a timely fashion, either in a different proceeding or an expanded Phase II, as interconnection challenges are extensive and crippling to a healthy renewable energy industry.

The Coalition is also not addressing all the issues in Phase I. Issues that the Coalition is not addressing include Issue 2B (how environmental attributes should be defined), Issue 3E (use of the Renewable Portfolio Implementation Plan), Issue 4B (third-party transmission), Issues 5B (disaggregation of large QFs), Issue 5C (should resource technology impact the size threshold), and Issue 6E (mechanical availability). The Coalition may address these issues in rebuttal testimony, or in legal briefs.

<u>THE SCHEDULE FOR AVOIDED COST UPDATES</u>

Q. PLEASE SUMMARIZE WHAT IS THE ISSUE OF THE SCHEDULE FOR AVOIDED COST UPDATES?

A. Generally, avoided cost price changes should be consistently applied. Price changes should also be predictable in terms of how and when they occur. In addition, new avoided cost rates should be stable and effective for a significant period of time. Unfortunately, as prices have dropped over the past several years, there has not been consistent and stable prices nor has there been predictability regarding when price changes would occur. This has lead to numerous difficulties for all parties, resulting in formal complains and a dramatic rise in uncertainty for those projects seeking new power purchase agreements. Over the past few years, the Coalition has been dedicated to improving the overall implementation environment and processes for renewable projects attaining new power purchase agreements. Any changes should not compromise the fundamental concept of ratepayer neutrality or result in major changes to the Commission’s existing policies.

Further, it is necessary and appropriate to consider how the avoided cost price updating mechanisms are critically linked to other components of the power purchase process, including the creation of a legally enforceable obligation, contracting pre-requisites, steps and timelines of the contracting process, and the interconnection process to name a few. The Coalition recommended avoided cost updating process takes into account these related considerations.

Q. WHAT IS ARE THE COMMISSION'S CURRENT RULES AND REQUIREMENTS REGARDING THE SCHEDULE FOR AVOIDED COST UPDATES?

A. The Commission historically has allowed the utilities to update their avoided cost rates every two years coincident with the integrated resource planning ("IRP") process. Re Staff Investigation Relating to Electric Utility Purchases from QFs, Docket No. UM 1129, Order No. 05-584 at 29 (May 13, 2005). In Docket No. UM 1129, PacifiCorp proposed that utilities be allowed to update avoided costs more frequently than every two years, and Staff objected to the proposal:

> [C]alling it 'unbalanced' as it would allow a utility to update avoided costs when a change in circumstances causes the utility to be in a resource sufficient position, but would fail to direct a utility to update avoided costs when a change in circumstances causes the utility to be in a deficit resource position.

The Commission adopted Staff's recommendation, and affirmed the continued use of a two year filing cycle for avoided cost updates. Id. The Commission requires the utilities to update their avoided costs at least every two years, which is expected to be 30 days after IRP acknowledgement. When the IRP cycle has taken longer than two years, the Commission has allowed the utilities to also update their avoided cost rates 30 days after IRP acknowledgement, which has meant more than one update in a two year period. The Commission stated that it would also exercise its discretion to direct a utility to update its avoided costs within two years. Id.

Q. SINCE UM 1129, HAVE AVOIDED COST UPDATES ALWAYS BEEN UPDATED EVERY TWO YEARS AND 30 DAYS AFTER IRP ACKNOWLEDGEMENT?

A. No. All three utilities have proposed updates outside of the established process, which is demonstrated by their responses to the Coalition's data requests ("DRs"). Coalition/102, Lowe/1, 24, and 46 (PacifiCorp response to Coalition DR 1.3, PGE response to Coalition DR 003, and Idaho Power response to Coalition DR 1.3).

The Commission has also rejected two attempts to update avoided costs outside of the two-year cycle, one by qualifying facility advocates and one by Idaho Power Company. Re Idaho Power, Docket No. UE 241, Order No. 11-414 (Oct. 11, 2011); Re Staff Investigation, Docket No. UM 1129, Order No. 07-199 at 2-3 (May 22, 2007). While not allowing an early update, the Commission also suspended the obligation of Idaho Power to enter into new standard contracts for at least a 60-day period, based on concerns that the avoided costs were outdated. Re Idaho Power, Docket No. UE 244, Order No. 12-042 (Feb. 14, 2012). Thus, the Commission does not have a consistent application of policy regarding whether avoided cost updates can be filed outside of the standard two-year cycle. This results in significant pricing uncertainty to QFs negotiating contracts with the utilities.

Q. PLEASE EXPLAIN WHY IT IS IMPORTANT TO QFS THAT AVOIDED COST RATES ARE UPDATED AT A REGULAR AND CONSISTENT TIME.

A. Regulatory uncertainty is one of the most detrimental facets of renewable project development and continued operation. The timing of avoided cost updates impacts the ability of projects to plan with some reasonable certainty and attain power purchase agreements at the proper time. The concern of QFs is not exclusively what direction prices are moving, but whether they can complete a power purchase agreement without prices changing. Stability and predictability of avoided cost prices can only occur if the updating process is well understood and consistently applied.

The Coalition is not opposed to the utilities' desire to be able to update avoided cost prices more often than every two years, provided that the stability of prices and predictability in how and when prices changes are enhanced. In other words, more frequent updates can occur, but they should not happen at unscheduled times. In addition, updates should not be so frequent that QFs cannot complete a power purchase agreement negotiation under one set of avoided cost rates.

Q. HAVE THE UTILITIES PROPOSED TO CHANGE THE CURRENT SCHEDULE OF AVOIDED COST UPDATES.

A. Yes. PacifiCorp has proposed to update avoided cost rates as often as practicable, and at least four times a year. PAC/100, Dickman/20-22. Idaho Power has proposed that avoided cost rates be updated annually for QFs eligible for standard contracts. Idaho Power/200, Stokes/66-67. PGE proposes to keep the current schedule of updates, but allow for an update within 30 days of the awarding of a bid for a major resource acquisition on which the demarcation of the resource deficiency/sufficiency period is based. PGE/100, Macfarlane-Morton/16.

Q. PLEASE RESPOND TO THE UTILITIES' PROPOSALS.

A. These proposals by Idaho Power and PacifiCorp could significantly harm both new and existing QFs. The most important aspect of the negotiation process for QFs is that they have certainty in terms of timelines and avoided cost rates. A QF should have certainty in terms of knowing when a utility will propose updates to its avoided cost rates, so that it can decide the most appropriate time to commence the negotiation process. Providing all parties with clarity regarding when avoided costs can be updated will reduce the number of disputes that are brought before the Commission.

Assuming that a QF starts the negotiation process far enough in advance of a scheduled change in the avoided cost rates, a QF should also have certainty that the avoided cost rates will not change during the negotiation process. PacifiCorp's proposal to have quarterly updates would completely remove any price certainty that a QF might have during the negotiation process, because the avoided cost rates would be constantly changing. Updating the avoided cost rates four times a year could have a devastating impact on any QF attempting to negotiate a contract with an Oregon utility.

Frequent updates also provide the utilities with additional opportunities to delay and impose barriers in the negotiation process for all QFs. There is an asymmetrical level of information between the utilities and QFs, which includes whether an update will increase or decrease the avoided cost rates. Utilities have an incentive to delay the negotiation process or impose other barriers to finalizing a contract if avoided cost rates are declining, and the opposite incentive if avoided cost rates are increasing. Allowing more frequent updates will provide an additional incentive for the utilities to impose barriers and delay the negotiating process, which may potentially increase the number of disputes between QFs and utilities. Overall, notwithstanding the possible appropriateness of annual updates, the utilities' proposals do not improve the Commission implementation of PURPA, and instead are significant and harmful departures from current policy and practices.

Q. DO YOU RECOMMEND THAT THE COMMISSION REVISE THE CURRENT SCHEDULE OF UPDATES EVERY TWO YEARS AND AT LEAST 30 DAYS AFTER ACKNOWLEDGEMENT OF AN IRP? (ISSUE 3A)

A. Yes.

Q. PLEASE SUMMARIZE THE COALITION'S RECOMMENDATION ON THE FREQUENCY OF AVOIDED COST RATE UPDATES.

A. The Coalition recommends that avoided cost rates be updated after the Commission acknowledges a utility's integrated resource plan. The current 30-day filing standard is acceptable. However, to accommodate the need to update avoided cost prices more frequently, the Coalition recommends that there be an annual update of avoided cost rates. These annual updates should not occur at a set calendar time, but should be filed one year from the effective date of the then-current prices.

Q. PLEASE DESCRIBE THE ANNUAL UPDATES.

A. The annual or mid IRP cycle updates should be based on information from the utility's last acknowledged integrated resource plan (or acknowledged plan update), with limited changes to account for new gas prices, new loads, and certain new contracts. Mr. Schoenbeck describes in greater detail what additional information should be included in the annual or mid-cycle updates.

Q. WHAT DO YOU RECOMMEND IF AN ANNUAL UPDATE IS SCHEDULED TO OCCUR CLOSE TO WHEN AN INTEGRATED RESOURCE PLAN IS SCHEDULED TO BE ACKNOWLEDGED?

A. If an annual update is scheduled to occur within 90 days of when an integrated resource plan is scheduled to be acknowledged, then the Coalition recommends that the annual update be deferred until after IRP acknowledgement. This will avoid the problem of having two major changes to avoided cost rates within months of each other, something which is contrary to the notion of reasonable price stability. The Coalition's recommendation will still result in more frequent avoided cost updates than under the current schedule, in which avoided cost rates are scheduled to be updated once every two years.

Q. DO YOU OPPOSE INCLUDING INFORMATION FROM IRPS THAT ARE IN THEIR LATE STAGES OF DEVELOPMENT?

A. Yes. The information in an integrated resource plan that has not been acknowledged has not been fully vetted by the Commission and should not be used to set avoided cost rates. Given that the Coalition is recommending an annual update process, the most important information for avoided cost rates (e.g., the gas price forecast, new loads and new large resources) will have been updated recently. Therefore, Coalition recommends that avoided cost prices updates or mid-cycle updates always be based upon the then-current IRP.

Q. WHY DO YOU OPPOSE UPDATING AT TIMES OTHER THAN A SET, ANNUAL UPDATE?

A. The primary reason is to enhance stability of prices and to eliminate "pancaking" of prices changes. Current experience with other jurisdictions involving PacifiCorp would demonstrate that holding to a set date does not work well and eventually another "set" date would be required. Stability of prices is enhanced when pancaking of prices is eliminated by a process that always results in price changes no less than one year apart.

Q. DO YOU RECOMMEND THAT THE UTILITIES PROVIDE NOTICE BEFORE THEY FILE AVOIDED COST UPDATES?

A. Yes. Many QFs do not know when avoided cost rates will be updated. Rather than just having filings made and then becoming effective within short periods of time, it would be helpful for QFs to have notice of an intended filing. This would allow for additional time to complete power purchase agreements and ultimately minimize conflicts over such agreements. The utilities should be required to provide 60 days' notice to all QFs they are negotiating a power purchase agreement with prior to filing any avoided cost update.

Q. WHAT DO YOU RECOMMEND IN TERMS OF A REVIEW OF AN AVOIDED COST RATE UPDATE?

A. Assuming such mid-cycle avoided cost prices filings have had reasonable notice and are limited to the items discussed in Mr. Schoenbeck's testimony, the current process of the Commission considering possible suspension for review within a 30-day period following such filing should be retained.

Q. SHOULD THE COMMISSION SPECIFY CRITERIA TO DETERMINE WHETHER AND WHEN QUICKER UPDATES SHOULD OCCUR, AND SHOULD THE COMMISSION SPECIFY WHAT FACTORS CAN BE UPDATED MID-CYCLE? (ISSUE 3B & 3C)

A. There should be no updates outside of the annual update and update following acknowledgement of the IRP. Not all QFs are aware of the Commission's regular cycle of updates, but for those who are aware of the update cycle, they plan to complete their negotiation process before a scheduled update will occur. This is so they can obtain price certainty and not have their avoided cost rates significantly change in the middle of the negotiation process. A QF should be able to plan on whatever cycle the Commission approves remaining in effect, and the Commission should make it clear that out of cycle updates close to the normally scheduled update are particularly inappropriate.

Q. TO WHAT EXTENT SHOULD DATA FROM IRPS THAT ARE IN LATE STAGES OF REVIEW AND WHOSE ACKNOWLEDGEMENT IS PENDING BE FACTORED INTO THE CALCULATION OF AVOIDED COST RATE UPDATES? (ISSUE 3D)

A. Use of data from late stage IRPs should not be used to increase the frequency of avoided cost rate changes nor should the Commission allow for updates outside of the normal scheduled process.

CONTRACTING ISSUES

Q. WHICH CONTRACTING ISSUES IS THE COALITION ADDRESSING?

A. Most contracting issues have been postponed to Phase II of this proceeding; however, issues 6B (when is there a legally enforceable obligation), 6E (how should contracts address mechanical availability), and 6I (what is the appropriate contract term) are within Phase I.

Q. WHY IS THE LEGALLY ENFORCEABLE OBLIGATION ISSUE IMPORTANT FOR QFS? (ISSUE 6B)

A. The creation of such obligation establishes certainty that a QF will receive a power purchase agreement including the then-currently effective prices.

Q. HAS FERC RECENTLY ADDRESSED THE LEGALLY ENFORCEABLE OBLIGATION ISSUE?

A. Yes. I am not addressing the legal issues associated with a legally enforceable obligation, but I am responding to PacifiCorp and Idaho Power's recommendations regarding when a legally enforceable obligation should commence.

Q. WHAT ARE SOME OF THE ROAD BLOCKS OR OBSTACLES THAT UTILITIES CAN IMPOSE, OR HAVE IMPOSED, UPON QFS SEEKING TO OBTAIN A LEGALLY ENFORCEABLE OBLIGATION, EVEN THOSE NEGOTIATING A STANDARD CONTRACT?

A. There are a number of common techniques. One is the imposition of pre-requisites to commencement of the contracting process. This includes interconnection related issues, such as completion of an interconnection agreement. Another is extending negotiations so a final draft agreement cannot be completed prior to new prices becoming effective. In addition, there can be a lack of willingness to complete or begin contract development if price changes are in progress. This is especially a problem when the maximum timeframes for completion of such agreement can result in a final agreement being signed after new prices become effective. Most obstacles are a result of downward price changes mixed with the misalignment of the avoided cost prices update process. All these obstacles are subject to abuse and could be significantly improved upon with relatively minor changes to policy, practices and rules.

Q. PACIFICORP DESCRIBES ITS EXPERIENCE WITH QFS THAT DO NOT FOLLOW THE APPROPRIATE PROCEDURES WHEN REQUESTING CONTRACTS. PAC/200, GRISWOLD/28-29. ARE THESE EXAMPLES ILLUSTRATIVE OF YOUR EXPERIENCE WORKING ON BEHALF OF PACIFICORP AND ON BEHALF OF QFS?

A. Without question, the contracting process can be abused by all parties involved. And there needs to be minimum requirements, timeframes and consistent application of all phases including how and when avoided cost prices change. QFs should not be allowed or have the expectation that copying a form standard agreement from a website and completing it with a signature is adequate to lock-in contract terms. Utilities, on the other hand, should not be allowed to employ avoidance and delay tactics when prices are moving downward, or take advantage of a QF's inability to meet requirements or terms associated with interconnection that are out of their control.

Q. PACIFICORP HAS PROPOSED USING ITS CURRENT SCHEDULE 37 PROCESS, WITH A MINOR CHANGE THAT A LEGALLY ENFORCEABLE OBLIGATION ARISES WHEN THE QF APPROVES THE FINAL DRAFT PPA. PAC/200, GRISWOLD/30. IS THIS CHANGE SUFFICIENT?

A. No, not entirely. PacifiCorp's proposed change is helpful and clearly movement in the appropriate direction, because it reduces the ability to delay after the final draft PPA is presented to the QF; however, it does not reduce or eliminate the utility's ability to delay the process before the final PPA is presented to the QF. A QF should be able to create a legally enforceable obligation prior to when the final PPA is offered. Other changes to the Schedule 37 process are necessary in order to establish a balanced path to creation of a legally enforceable obligation, and this issue will be addressed in Phase II.

Q. PLEASE EXPLAIN IDAHO POWER'S POSITION ON LEGALLY ENFORCEABLE OBLIGATION.

A. Idaho Power proposes that a QF must sign a contract, and that a QF should not be allowed to create a legally enforceable obligation unless there is some evidence of a utility's refusal to contract. Idaho Power/200, Stokes/80. From a policy perspective and based on my experience, I disagree with Idaho Power. First, a QF should not be required to sign a draft contract that may have numerous harmful or unfavorable provisions in order to obtain a legally enforceable obligation. A legally enforceable obligation should exist once the QF is ready to obligate itself to sell power to the utility based on reasonable terms and conditions, even if it is unwilling to sign a contract.

Second, a QF should not be required to demonstrate evidence of a utility's refusal to contract before a legally enforceable obligation in created without a signed contract. I have worked on both the utility and QF side of negotiations, and there are numerous ways that a utility can slow the process or impose roadblocks and other hurdles that, to an outside observer, may not appear as refusing to contract. Requiring a QF, which may be unsophisticated and have limited resources, to demonstrate a refusal of the utility to contract is an unnecessary and potentially difficult burden.

Q. PLEASE EXPLAIN PGE'S POSITION ON LEGALLY ENFORCEABLE OBLIGATION.

A. Unlike Idaho Power and PacifiCorp, PGE has elected not to address the issue of when a legally enforceable obligation is made and has stated that the issue is a legal one. The Coalition attempted to obtain PGE's position on the legally enforceable obligation issue, including whether PGE agrees with the testimony of PacifiCorp and Idaho Power, and whether PGE believes that any changes should be made to the current rules. Coalition/102, Lowe/40-42. PGE, however, has refused to provide its position on these basic issues, but appears likely to address the issue only in legal briefs. This places the other parties at a disadvantage, and the Commission should give less weight to any recommendations that could have, but were not, raised in testimony.

Q. WHAT ISSUE REGARDING LEGALLY ENFORCEABLE OBLIGATIONS DID PGE TESTIFY TO?

A. PGE testified that a legally enforceable obligation should not occur any greater than one year before power deliveries. PGE/100, Macfarlane-Morton/23.

Q. WAS THE COALITION PLANNING TO ADDRESS THIS ISSUE IN PHASE II?

A. Yes. Phase II includes the Issue 6C (what is the maximum time allowed between contract execution and power delivery). Re Investigation Into QF Contracting and Pricing, Docket No. UM 1610, Ruling (Oct. 25, 2012). The key aspect of both Issue 6C and PGE's recommendation that a QF cannot enter into a contract greater than one year is how much time between contract execution (either a signed contract or other legally enforceable obligation) and power delivery.

Q. WHY DO YOU BELIEVE THIS ISSUE SHOULD BE ADDRESSED LATER?

A. Setting the legally enforceable obligation issue aside, it is difficult for execution of a power purchase agreement to be followed by power deliveries by no later than one year later. Project financing, equipment ordering, project contracting and construction are just a short list of critical project development steps occurring after completion of a power purchase agreement. The interconnection process alone, although probably started with the study phase at the time of power purchase agreement execution, could easily take another 18 to 24 months to complete. Since Commission's Order No. 05-584, many PacifiCorp QFs still take longer than a year, and up to over two years, to negotiate their contracts.

Q. IS THERE INFORMATION LACKING ON THIS ISSUE?

A. Yes. PacifiCorp and Idaho Power have not addressed the issue of how long between contract execution (or other legal obligations) and power deliveries. All Coalition projects in Oregon sell their power to Idaho Power and PacifiCorp, and the Coalition needs to know their position on this issue and to conduct discovery on their negotiation process before fully addressing this issue.

Q. IF THE COMMISSION ADDRESSES THIS ISSUE IN PHASE I, WHAT DO YOU RECOMMEND?

A. The Commission should reject the one year limitation proposed by PGE as arbitrary and unreasonable, and practically impossible for most QFs. PGE has not provided any information about how long before power deliveries a QF needs to sign its power purchase agreement due to negotiation issues, interconnection issues, and the timing of avoided cost rate updates. PGE has also not provided any information regarding how long prior to power deliveries PGE enters into non-QF contracts or its own self-built resources. Essentially, PGE has provided no factual information to support a one year (or any other) limitation on the time between contract execution (or other legal obligation) and power delivery.

If the Commission addresses this issue in Phase I, then the Commission should decide that the amount of time between a contract execution (or legal obligation) and power deliveries should be no less than the amount of time needed to complete its interconnection and other requirements such as financing and construction. Only after resolving the issues regarding the timing of avoided cost rate updates and only in light of the Phase II testimony on the power purchase negotiation process and interconnection issues, should the Commission consider setting a specific amount of time between contract execution (or other legal obligation) and power deliveries.

Q. WHAT CHANGES DO YOU THINK SHOULD BE MADE IN OREGON TO PREVENT STONEWALLING BY UTILITIES AND TO ENSURE CONSISTENCY WITH FERC?

A. The Commission should make further revisions to the timelines and negotiation process, which will be addressed in Phase II of this case. In addition to the changes that will be addressed in Phase II, the Commission should revise its rules and policies in Phase I to make it clear that a binding, written obligation is not necessary to form a legally enforceable obligation.

Next, based on the facts of the particular circumstances, a QF should be allowed to form a legally enforceable obligation prior to date in which a utility provides a final power purchase agreement. In my experience, utilities can make minor revisions to power purchase agreements or impose new conditions in the negotiation process which can impose difficult burdens and slow the process. Once a QF has provided all the required information to the utility and after the utility has provided a draft power purchase agreement, then QF should be allowed to obligate itself to sell power based on then current avoided cost rates.

In addition, a QF should not be required to sign a utility's draft power purchase agreement to form a legally enforceable obligation. If the utility provides a draft power purchase agreement that includes provisions that are illegal or otherwise inconsistent with Commission policy, then the QF should have the right to obligate itself to sell power under the current avoided cost rates. The Commission may be required to resolve whether the terms of the power purchase agreement are consistent with law and policy, but a QF should not be required to agree to potentially illegally terms or conditions in order to demonstrate that it is willing to sell power under reasonable terms and conditions.

As I discussed above, a QF should not be required to affirmatively demonstrate that a utility delayed the negotiation process or did not act in good faith. Such a demonstration can be very difficult to establish. In addition, there may be times when good faith negotiations simply fail to reach an agreement and there may be legitimate disputes that prevent the parties from reaching a signed, written contract. A QF should be allowed to obligate itself to sell power under the current avoided cost rates at reasonable terms and conditions, even if the parties cannot reach an agreement on a written contract.

Q. WHAT IS THE CURRENT OPUC POLICY ON CONTRACT DURATION? (ISSUE 6I)?

A. The Commission's policy is that QFs should have the option to select contracts of up to 20 years, with fixed prices for the first 15 years. Re Investigation Relating to Electric Utility Purchases from QFs, Docket No. UM 1129, Order No. 05-584 at 19-20 (May 13, 2005). The Commission rejected proposals for longer and shorter terms, and concluded that the 15 year term was a reasonable balance. The Commission also concluded that the length of the contract should take into account the needs of QFs, including the need to obtain financing for their projects. Id.

Q. HAVE THE UTILITIES PROPOSED CHANGES TO THE CONTRACT DURATION?

A. Yes. All three utilities have proposed changes that would harm QFs. PacifiCorp and Idaho Power support continued use of a 20 year maximum length of the contract, but propose that the fixed price component of the contract be shortened from 15 to 10 years. PAC/200, Griswold/31-32; Idaho Power/200, Stokes/73-74. PGE supports continuation of the current policy for new QFs, but recommends a five year term for existing QFs. PGE/100, Macfarlane-Morton/23-24.

Q. PLEASE EXPLAIN WHY A FIXED 15-YEAR TERM IS IMPORTANT FOR QFS.

A. In addition to what Mr. Schoenbeck addresses in his testimony, longer term agreements are needed to meet financing and long-term planning needs. New projects certainly need the longer term in order to meet debt requirements. Even existing projects require long term agreements for system improvement projects and planning. This is especially true for QFs that are water systems, such as irrigation districts. There are other reasons why longer-term agreements are necessary, one of which is the avoidance of market based energy only prices during periods of resource sufficiency. As discussed further in my testimony below, a five-year term limit on existing projects not only is problematic in terms of regularly needing new power agreements but exposes the QFs much lower prices (total value) than would result from a single long-term contract.

Q. DO YOU RECOMMEND ANY CHANGES IN THE OPUC'S CONTRACT DURATION POLICY?

A. No. Maintaining the 15-year term for all QFs (both existing and new) is critical to the QF industry.

AVOIDED COST PRICE CALCULATIONS

Q. PLEASE SUMMARIZE THE ISSUES RELATED THE AVOIDED COST PRICE CALCULATION ISSUES THAT YOU ARE ADDRESSING AND THOSE THAT WILL BE ADDRESSED BY MR. SCHOENBECK.

A. I am addressing Issue 1B regarding levelized prices, Issue 1D regarding the elimination of pricing options, and Issue 1A2 regarding whether the methodology should be the same for all utilities, and Mr. Schoenbeck is addressing Issue 1A1 regarding the appropriate methodology for calculating avoided cost prices. Both of us are addressing Issue 1C regarding pricing during the resource sufficiency period.

Q. SHOULD QFS SEEKING RENEWAL OR REPLACEMENT OF A STANDARD CONTRACT DURING A UTILITY'S SUFFICIENCY PERIOD BE PAID A CONTINUUM OF CAPACITY (ISSUE 1C).

A. Yes, all existing projects seeking a replacement of a firm contract should continue to receive capacity payments or value for capacity.

Q. WHAT HAVE THE UTILITIES PROPOSED ON THIS ISSUE?

A. PGE and PacifiCorp have proposed that QFs renewing their contracts not be allowed to obtain a capacity payment during the resource sufficiency period. PAC/100, Dickman/16; PGE/100, Macfarlane-Morton/14. Idaho Power, however, at the workshop on February 25, 2013 in Salem indicated that their position was to retain exactly the same approach ordered by the Idaho Public Utility Commission in Case GNR-E-11-03, Order No. 32697, whereby the utilities are required to continue to pay for capacity.

Q. DO YOU AGREE WITH PACIFICORP THAT PAYING RENEWING QFS A CAPACITY PAYMENT HAS THE SAME EFFECT AS OFFERING LONGER THAN 20-YEAR CONTRACTS?

A. No. A replacement agreement is not part of the term of the agreement being replaced. As long as the QF was considered a firm resource and the new contract will be a firm contract, then the new contract should be considered as firm contract for it entire duration. Since existing projects have been part of the Utilities' resource portfolio, they should be treated differently when it comes to this component of the appropriate avoided cost prices and not receive resource sufficiency prices.

Q. PLEASE EXPLAIN THE PRACTICAL EFFECT OF PGE'S COMBINED PROPOSALS NOT TO PAY RENEWING QFS A CAPACITY PAYMENT AND TO SHORTEN THE CONTRACT LENGTH TO 5 YEARS.

A. The short answer is that it would be highly destructive to the renewable energy industry. The net present value of multiple 5-year contracts containing a number of years of energy only prices for each new five-year term is dramatically lower than a single long-term contract containing only a few years of resource sufficiency based prices. Fuel based projects such as biomass would likely cease to operate, and in some cases the revenue from such short term contracts without payment for capacity would not be adequate to keep existing hydroelectric projects operational.

Q. HAS THE IDAHO COMMISSION ADDRESSED THIS ISSUE?

A. Yes, and in Order No. 32697, utilities are required to pay for capacity from existing projects seeking new replacements contracts with the original utility purchaser.

Q. SHOULD QFS BE ABLE TO SELECT LEVELIZED AVOIDED COSTS? (ISSUE 1B)

A. Maybe in certain circumstances and, if so, only to a limited degree. New projects have some flexibility to time their on-line date with the commencement of resource deficiency based avoided cost prices; existing project have no such flexibility as their contract expiration dates are determined long in advance. Levelization of prices may not be necessary at all if contract terms are adequately long such as 15-years, and existing projects continue to receive value for capacity when entering into a replacement power purchase agreement. Levelization could be a mute point if five-year contract term limit is established since such term combined with lack of payment for capacity would result in most projects shutting down.

Q. SHOULD THE METHODOLOGY BE THE SAME FOR ALL THREE UTILITIES? (ISSUE 1AB)

A. No. The Coalition agrees with Idaho Power that it should be able to apply the methodologies it uses in Idaho, including discreet prices for different technologies and operating regimes. This would more precisely apply avoided costs based upon the value a specific project brings to the utility. However, it would be unfair if utilities were able to pick and choose the elements to their advantage from each state in creating a hybrid approach.

RENEWABLE AVOIDED COST CALCULATIONS

Q. WHAT RENEWABLE AVOIDED COST CALCULATION ISSUES ARE YOU ADDRESSING?

A. I am addressing issue 2C on should non-energy attributes be retained by the QF. Mr. Schoenbeck is addressing Issue 2A regarding different avoided costs for resource type.

Q. DO QFS CURRENTLY RETAIN THE NON-ENERGY ATTRIBUTES (ISSUE 2C)?

A. Yes. The Commission's current policy is that a QF owns the non-energy attributes, including green tags, renewable energy credits, tradable renewable certificates and other attributes. Re Rulemaking, Docket No. AR 495, Order No. 05-1229 (Nov. 28, 2005); OAR § 860-022-0075. A QF can sell these non-energy attributes to the utility, but can elect to sell them to third parties.

Q. DO YOU AGREE WITH THIS POLICY?

A. Yes. Non-energy attributes are valuable commodities that are different and distinct from the power generated and sold to the utility. There are separate markets for the non-energy attributes, and they do not have to be bought or sold with the power. Standard avoided cost rates do not include compensation for any social or environmental benefits that may be associated with the electricity generation, and are not intended to compensate the QF for anything other than the capacity and energy.

Q. HAVE THE UTILITIES RAISED ANY NEW ARGUMENTS THAT WOULD SUPPORT REVERSING THIS POLICY?

A. No. PacifiCorp appears to largely support the current policy with a revision that a QF should not retain the non-energy attributes if the QF sells renewable power under a renewable avoided cost rate during the renewable deficiency period. PAC/200, Griswold/9-10. PacifiCorp, however, has proposed a broad definition of non-energy attributes, which would result in the QF selling both renewable energy credits and all other non-power attributes to the utility during the renewable deficiency period. Id. PGE has not proposed any changes. PGE/100, Macfarlane-Morton/16.

Q. DO YOU SUPPORT PACIFICORP'S RECOMMENDATION?

A. No. I agree with PacifiCorp that any renewable energy credits associated with complying with a state renewable portfolio standard should be transferred to the utility during the resource deficiency period if the QF is selling renewable power at the renewable avoided cost rate. Non-energy attributes, however, may include other rights and benefits which are different from compliance with a state renewable portfolio standard, and those benefits should remain with the QF. The renewable avoided cost rates are intended to compensate the QF for the power and renewable energy credits, but not all the social and environmental benefits that may accrue due to the electricity being generated by a QF rather than a utility's generation resource.

ELIGIBILITY ISSUES

Q. PLEASE EXPLAIN THE ELIGIBILITY ISSUES THAT THE COALITION IS ADDRESSING IN THIS PROCEEDING.

A. All of the Coalition's witnesses will address issue 5A regarding the size threshold for standard contracts, and I will address the issue 5D regarding whether a QF receive Oregon's renewable avoided cost price if the QF owner will sell the renewable energy credits in another state.

Q. WHAT IS THE COMMISSION'S CURRENT POLICY ON THE SIZE THRESHOLD FOR QFS? (ISSUE 5A)

A. Currently all projects 10 MW or less are provided access to standard form contracts and published prices, none of which requires any or significant negotiation

Q. HAS THE COMMISSION'S CURRENT POLICY ACHIEVED ITS PURPOSES AND GOALS?

A. Yes, all except one of the Coalition's Oregon member projects are provided access to standard contracts and published prices. This has resulted in moderate development rates for new projects and has contributed to the continuing operation of many existing projects.

Q. DO THE UTILITIES' HISTORIES OF ENTERING INTO QF CONTRACTS DEMONSTRATE THAT THE 10 MW SIZE THRESHOLD IS IMPORTANT?

A. Yes. It is much more difficult for QFs to negotiate contracts over 10 MWs than fewer than 10 MWs. Even a cursory review of the QF contracts entered into the by the utilities demonstrates the importance of the size threshold. Coalition/102, Lowe/6-10, 26-28

(PacifiCorp response to Coalition DR 2.3; PGE response to Coalition DR 006); Idaho Power/201, Stokes/1-3.

Q. HAVE THE UTILITIES' PROPOSED CHANGES TO THE COMMISSION'S POLICY ON THE 10 MW SIZE THRESHOLD?

A. Yes. PacifiCorp has proposed a 3 MW size threshold, PGE has proposed a 100 kW size threshold, and Idaho Power has proposed to keep the 10 MW size threshold for most QFs, but lower the size threshold for wind and solar QFs. PAC/200, Griswold/16-21; PGE/100, Macfarlane-Morton/4-10; Idaho Power/200, Stokes/3.

Q. DO THE UTILITIES' CONCERNS ABOUT THE SIZE THRESHOLD APPEAR TO BE PRIMARILY RELATED TO DISAGGREGATION OF WIND QFS?

A. Yes. Each of the utilities' justification for the lower the size threshold is in part based on alleged concerns about wind QFs. PAC/200, Griswold/17; PGE/100, Macfarlane-Morton/4-10; Idaho Power/200, Stokes/19-20. Even if the utilities' concerns are legitimate, the Commission can address these issues in ways other than lowering the size threshold for all QFs.

Q. HAVE THE UTILITIES CLAIMED THAT LOWERING THE SIZE THRESHOLD WILL SAVE RATEPAYERS MONEY.

A. The utilities argue that standard contract QFs are more expensive than negotiated QF contracts. PAC/200, Griswold/17-20; PGE/100, Macfarlane-Morton/9-10; Idaho Power/200, Stokes/14-20.

Q. ARE THESE ALLEGATIONS SUPPORTED?

A. No. For example, PGE relies upon hypothetical QFs, not actual QF contracts. PGE/100, Macfarlane-Morton/9. This may be due to the fact that PGE has entered into very few QF contracts.

Q. ARE THE UTILITIES' CONCERNS ABOUT PRICING BETTER ADDRESSED BY THE COMMISSION ENSURING THAT AVOIDED COSTS ARE ACCURATE RATHER THAN LOWERING THE SIZE THRESHOLD FOR STANDARD CONTRACTS?

A. Yes.

Q. SHOULD AN OREGON QF RECEIVE OREGON'S RENEWABLE AVOIDED COST PRICE IF THE QF OWNER WILL SELL THE RECS IN ANOTHER STATE? (ISSUE 5D)

A. If the Oregon QF is selling power under the renewable avoided cost rate, then the QF should retain the renewable energy credits during the resource sufficiency period when the QF is being paid a market rate that does not account for the value of the renewable energy credit, but the QF should be required to transfer the renewable energy credit to the utility during the resource deficiency period. Thus, the Oregon QF should be able to sell any renewable energy credits associated with power generated during the resource sufficiency period anywhere, but should not be able to sell renewable energy credits associated with power generated during the resource deficiency period as those should be transferred to the utility.

Q. HAS THE COMMISSION ADDRESSED THIS ISSUE?

A. Yes. The Commission determined that, under the renewable avoided cost pricing option, a QF should retain the renewable energy credits during the resource sufficiency period, but must sell the renewable energy credits during the resource deficiency period. Re Investigation into Resource Sufficiency, Docket No. UM 1396, Order No. 11-505 at 9-10 (Dec. 13, 2011). This is consistent with my recommendation in this case.

PRICE ADJUSTMENTS FOR SPECIFIC QF CHARACTERISTICS

Q. WHAT ISSUES RELATED TO PRICE ADJUSTMENTS FOR SPECIFIC QF CHARACTERISTICS IS THE COALITION ADDRESSING?

A. Mr. Schoenbeck is addressing the issues of how the FERC factors should be taken into account (Issue 4C), and how the costs of integration are taken into account (Issue 4A).

Q. FOR STANDARD CONTRACTS, SHOULD THE UTILITIES BE ALLOWED TO PROPOSE ADJUSTMENTS TO THE AVOIDED COST RATES THAT HAVE NOT BEEN APPROVED BY THE COMMISSION?

A. No. The Commission addressed this issue UM 1129, and I agree with the Commission's conclusions. Specifically, the Commission explained that there should be no adjustments to standard contracts and pricing:

> Standard contracts are designed to minimize the need for parties to engage in contract negotiations. Consequently, any flexibility in the terms and conditions of a standard contract should be specifically delineated and bounced. To the extent that a party anticipated the need for flexibility with regard to a particular standard contract term or condition, the specific issue should have been raised and examined in this proceeding. It is inappropriate to request that standard contracts be subject to potential negotiation to address project-specific characteristics.

Order No. 05-584 at 39.

The Commission should reaffirm this policy in its final decision in this case. The Commission will not be able to resolve all issues that arise in the future, and utilities (or QFs) should be allowed to propose revised standard contract terms and conditions in the future. Any such changes, however, should only occur on a prospective basis. QFs who are negotiating contracts, especially those in the final stages of their negotiations, should not be subject to new requirements or penalties.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
	)
Investigation Into Qualifying Facility Contracting and Pricing	)
	)

EXHIBIT COALITION/101

QUALIFICATIONS OF JOHN LOWE

March 18, 2013

Overview

Director, Renewable Energy Coalition

Relevant Work Experience

2007-Present: Renewable Energy Coalition
Represent the Coalition and individual members in five regional states; power purchase agreement and interconnection consulting.

1975-2006: PacifiCorp, left as Manager of Qualifying Facility contracts, Portland, OR
Lead roles in company implementation of Public Utility Regulatory Policies Act, including, but not limited to power purchase agreements and interconnection contracting, staff supervision and management, and high level coordination of company's distribution interconnections for qualifying facilities.

1975: Graduate Oregon State, BS

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation Into Qualifying Facility Contracting and Pricing	)

EXHIBIT COALITION/102

UM 1610 Data Responses

March 18, 2013

UM 1610/PacifiCorp
January 24, 2013
REC Data Request 1.3

REC Data Request 1.3

In Oregon since 2000, please identify the date of each filing to change its avoided cost rates.

Response to REC Data Request 1.3

Please see below for a list of filing dates for changes to PacifiCorp's avoided cost rates in Oregon since 2000:

- Advice No. 01-017
  Filed: June 29, 2001

- Advice No. 03-016
  Filed: November 10, 2003

- Advice No. 05-006
  Filed: July 12, 2005

- Advice No. 06-019
  Filed: October 20, 2006

- Advice No. 07-014
  Filed: July 12, 2007

- Advice No. 07-021
  Filed: November 2, 2007

- Advice No. 09-012
  Filed: July 9, 2009

- Advice No. 10-005
  Filed: March 4, 2010

- Advice No. 12-005
  Filed: March 2, 2012

UM 1610/PacifiCorp
January 24, 2013
REC Data Request 1.4

REC Data Request 1.4

In Oregon since 2005, please identify the date for order acknowledging or not acknowledging each integrated resource plan.

Response to REC Data Request 1.4

Please see below for the requested order dates for integrated resource plans since 2005:

2004 IRP	Oregon Docket: LC 39	January 23, 2006
2007 IRP	Oregon Docket: LC 42	April 24, 2008
2008 IRP	Oregon Docket: LC 47	February 24, 2010
2011 IRP	Oregon Docket: LC 52	March 9, 2012

UM 1610/PacifiCorp
January 24, 2013
REC Data Request 1.5

REC Data Request 1.5

In the Company's last acknowledged integrated resource plan, please explain whether the capacity and energy of existing QF contracts are considered existing resources. If not, please explain why not. If so, please identify whether the Company assumes that its existing QF contracts will continue for the planning period, and how much energy and capacity is counted for each existing QF contract.

Response to REC Data Request 1.5

Yes. The capacity and energy of existing qualifying facility (QF) contracts in the Company's last acknowledged integrated resource plan (IRP) are considered existing resources. The QF contracts were treated as if the contracts renewed, so they will continue over the planning study period.

Please refer to Confidential Attachment REC 1.5, which provides QF contract capacity and energy data.

Information in Confidential Attachment REC 1.5 is designated as confidential under the protective order in this docket and may only be disclosed to qualified persons as defined in Order No. 12-461.

UM 1610/PacifiCorp
January 24, 2013
REC Data Request 1.6

REC Data Request 1.6

Except for Oregon, for each state the Company operates it, please identify whether the QF or the Company retains the renewable energy credits and other environmental attributes associated with QF power sold to the Company. If the Company retains the renewable energy credits and/or environmental attributes, please identify whether the price for QF power is adjusted to account for the renewable energy credits and/or environmental attributes.

Response to REC Data Request 1.6

Please refer to Attachment REC 1.6.

Qualifying Facility (QF) and Renewable Energy Credits (RECs)

State	MW Cap for Standard Avoided Cost Prices [1]	Renewable Energy Credits ("RECs")		Avoided cost price adjusted to account for RECs or environmental attributes
		QF Projects below MW Cap	QF Projects above MW Cap	
California	0.1 MW	Per CPUC Decision R.06-02-012 and Order 9696, RECs are owned by utility as part of net output purchase for the term of the power purchase agreement.	Per CPUC Decision R.06-02-012 and Order 9696, RECs are owned by utility as part of net output purchase for the term of the power purchase agreement.	No
Idaho	10 average MW output except wind and solar which are 100 kW nameplate	RECs retained by QF when using SAR Methodology (Case GNR E-11-03 Order 32697, page 47).	Apportion RECs equally between the QF and the utility when using IRP Methodology Case GNR E-11-03 Order 32697, page 47).	No
Oregon	10 MW	QF retains RECs (Order No. 05-1229). UM 1396 Order 11-505 modified. If QF chose renewable avoided cost prices then QF retains the RECs during resource sufficiency period and utility owns RECs during resource deficiency period. If QF chose standard avoided cost prices then QF retains RECs.	QF retains RECs (Order No. 05-1229). UM 1396 Order 11-505 modified. If QF chose renewable avoided cost prices then QF retains the RECs during resource sufficiency period and utility owns RECs during resource deficiency period. If QF chose standard avoided cost prices then QF retains RECs.	No
Utah	1MW for cogeneration 3 MW for other small power production	Not determined. No decision or formal order at this time by Utah Public Service Commission.	PacifiCorp owns the RECs for wind projects but the QF can buy back from PacifiCorp at PacifiCorp's price in its integrated resource plan (Order in Docket 03-035-14). No formal order by Utah Public Service Commission on REC ownership for non-wind QFs.	No
Washington	2 MW	No decision or Washington Commission Order on RECs regardless of size.	No decision or Washington Commission Order on RECs regardless of size.	No
Wyoming	1 MW (at or below 70% capacity factor) 10 MW (above 70% capacity factor)	Utility owns the RECs for the term of the power purchase agreement regardless of size of QF. (Docket No. 20000-250-EA-06).	Utility owns the RECs for the term of the power purchase agreement regardless of size of QF. (Docket No. 20000-250-EA-06).	No

[1] Nameplate Capacity unless noted

UM 1610/PacifiCorp
February 26, 2013
REC Data Request 2.3

REC Data Request 2.3

Regarding PacifiCorp response to REC DR 1.2, please provide a redacted copy of the response. For each piece of information the Company believes should be confidential, please provide the full legal basis for why the information should be considered confidential.

Response to REC Data Request 2.3

Referring to the Company's response to REC Data Request 1.2; specifically Confidential Attachment REC 1.2, the Company considers columns "b," "c," and "f" to be confidential.

Please refer to Attachment REC 2.3, which provides a redacted version of Confidential Attachment REC 1.2. The Company objects to this request to the extent that it calls for a legal conclusion. Without waiving this objection, the Company responds as follows: the redacted columns are confidential because the data therein constitute a trade secret or other confidential research, development, or commercial information under ORCP 36(C)(7).

a	b	c	d	e	f	g	h	i	j (see Note 1)	k	l
Plant Name	**Entitlement Start Date**	**Entitlement End Date**	**Term (Years)**	**Nameplate or Contract Capacity (MW)**	**2011 Average Output (aMW)**	**Resource Type**	**State**	**CA**	**OR**	**WA**	**REC Entitlement (PacifiCorp, QF or Not Determined by State (at this time) (see Note 2))**
AG Hydro	[redacted]	[redacted]	20.0	10.00	[redacted]	Hydro	OR				QF
Ballard Hog Farms Inc	[redacted]	[redacted]	5.1	0.05	[redacted]	Biogas	UT	60783E			Not Determined by State (at this time)
Ballard Hog Farms Inc (renewal)	[redacted]	[redacted]	2.1	0.05	[redacted]	Biogas	UT				Not Determined by State (at this time)
Ballard Hog Farms Inc (renewal)	[redacted]	[redacted]	2.0	0.05	[redacted]	Biogas	UT				Not Determined by State (at this time)
Ballard Hog Farms Inc (renewal)	[redacted]	[redacted]	7.1	0.05	[redacted]	Biogas	UT				Not Determined by State (at this time)
Bell Mountain Hydro LLC (Ted Sorenson)	[redacted]	[redacted]	19.6	0.28	[redacted]	Hydro	ID				Not Determined by State (at this time)
Bell Mountain Power (Jake Amy)	[redacted]	[redacted]	37.0	0.45	[redacted]	Hydro	ID				Not Determined by State (at this time)
Big Top LLC (QF)	[redacted]	[redacted]	20.1	1.65	[redacted]	Wind	OR				QF
Biomass One, L.P.	[redacted]	[redacted]	24.6	25.00	[redacted]	Biomass	OR				Not Determined by State (at this time)
Biomass One, L.P. (renewal)	[redacted]	[redacted]	15.0	32.25	[redacted]	Biomass	OR				QF
Birch Creek Hydro	[redacted]	[redacted]	27.6	2.65	[redacted]	Hydro	ID				Not Determined by State (at this time)
Bogus Creek	[redacted]	[redacted]	34.8	0.16	[redacted]	Hydro	CA				Not Determined by State (at this time)
Bogus Creek (renewal)	[redacted]	[redacted]	43.0	0.16	[redacted]	Hydro	CA	60780E, 60781E			Not Determined by State (at this time)
Bureau of Land Management - Rawlins Office	[redacted]	[redacted]	10.1	0.10	[redacted]	Wind	WY				PacifiCorp
Butter Creek Power LLC	[redacted]	[redacted]	20.1	4.95	[redacted]	Wind	OR				QF
C Drop	[redacted]	[redacted]	20.0	1.10	[redacted]	Hydro	OR				QF
Cargill, Q3 (Kettle Butte Dairy)	[redacted]	[redacted]	9.7	1.70	[redacted]	Biogas	ID				QF
CBG Portland	[redacted]	[redacted]	21.4	3.00	[redacted]	Biogas	OR				QF
CDM Hydro	[redacted]	[redacted]	36.3	6.00	[redacted]	Hydro	ID				Not Determined by State (at this time)
Central Oregon Irrigation District	[redacted]	[redacted]	31.4	6.00	[redacted]	Hydro	OR				Not Determined by State (at this time)
Central Oregon Irrigation District - Juniper Ridge	[redacted]	[redacted]	21.0	5.00	[redacted]	Hydro	OR				QF
Chevron Wyoming Wind QF	[redacted]	[redacted]	5.0	16.50	[redacted]	Wind	WY	60975A	10wnd002wy		PacifiCorp
City of Albany, Dept of Public Works	[redacted]	[redacted]	15.5	0.50	[redacted]	Hydro	OR				QF
City of Buffalo	[redacted]	[redacted]	17.7	0.20	[redacted]	Hydro	WY				Not Determined by State (at this time)
City of Portland, Portland Hydro Bureau	[redacted]	[redacted]	15.3	0.03	[redacted]	Hydro	OR				QF
Commercial Energy Management	[redacted]	[redacted]	28.4	0.90	[redacted]	Hydro	ID				Not Determined by State (at this time)
Cottonwood Hydro Lower	[redacted]	[redacted]	1.4	0.85	[redacted]	Hydro	UT				Not Determined by State (at this time)
Cottonwood Hydro Lower (renewal)	[redacted]	[redacted]	2.0	0.85	[redacted]	Hydro	UT				QF
Cottonwood Hydro Lower (renewal)	[redacted]	[redacted]	4.0	0.85	[redacted]	Hydro	UT				QF
Cottonwood Hydro Upper	[redacted]	[redacted]	4.0	0.26	[redacted]	Hydro	UT				QF
Curtiss Livestock (Cameron Curtis)	[redacted]	[redacted]	20.0	0.08	[redacted]	Hydro	OR				Not Determined by State (at this time)
Curtiss Livestock (Cameron Curtis) (renewal)	[redacted]	[redacted]	2.0	0.08	[redacted]	Hydro	OR				Not Determined by State (at this time)
Curtiss Livestock (Cameron Curtis) (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				Not Determined by State (at this time)
Curtiss Livestock (Cameron Curtis) (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				Not Determined by State (at this time)
Curtiss Livestock (Cameron Curtis) (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				QF
Curtiss Livestock (Cameron Curtis) (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				QF
Curtiss Livestock (Cameron Curtis) (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				QF
Curtiss Livestock (Cameron Curtis) (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				QF
Curtiss Livestock (Cameron Curtis) (renewal)	[redacted]	[redacted]	5.0	0.08	[redacted]	Hydro	OR				QF
Deruyter Dairy	[redacted]	[redacted]	3.0	1.20	[redacted]	Biogas	WA	60698A			QF
Deruyter Dairy (renewal)	[redacted]	[redacted]	3.2	1.20	[redacted]	Biogas	WA				QF
Deruyter Dairy (renewal)	[redacted]	[redacted]	0.5	1.20	[redacted]	Biogas	WA				QF
Deruyter Dairy (renewal)	[redacted]	[redacted]	2.8	1.20	[redacted]	Biogas	WA				QF
Deruyter Dairy (renewal)	[redacted]	[redacted]	1.0	1.20	[redacted]	Biogas	WA				QF
Deschutes Valley Hydro District	[redacted]	[redacted]	38.2	4.30	[redacted]	Hydro	OR				Not Determined by State (at this time)
Dorena Hydro	[redacted]	[redacted]	20.0	6.10	[redacted]	Hydro	OR				QF
Douglas Country Forest Products	[redacted]	[redacted]	2.0	6.25	[redacted]	Biomass	OR				Not Determined by State (at this time)
Douglas Country Forest Products (renewal)	[redacted]	[redacted]	2.0	6.25	[redacted]	Biomass	OR				QF
Douglas Country Forest Products (renewal)	[redacted]	[redacted]	5.0	6.25	[redacted]	Biomass	OR				QF
Draper Irrigation Company	[redacted]	[redacted]	2.0	0.51	[redacted]	Hydro	UT	60788A			Not Determined by State (at this time)
Draper Irrigation Company (renewal)	[redacted]	[redacted]	3.0	0.51	[redacted]	Hydro	UT				Not Determined by State (at this time)
Draper Irrigation Company (renewal)	[redacted]	[redacted]	1.0	0.51	[redacted]	Hydro	UT				QF
Draper Irrigation Company (renewal)	[redacted]	[redacted]	20.0	0.51	[redacted]	Hydro	UT				QF
Dry Creek	[redacted]	[redacted]	36.0	4.00	[redacted]	Hydro	ID				Not Determined by State (at this time)
Duane Wiggins Hydro	[redacted]	[redacted]	3.1	0.02	[redacted]	Hydro	OR				Not Determined by State (at this time)
Eagle Point Irrigation District (Nichols Gap)	[redacted]	[redacted]	38.3	0.72	[redacted]	Hydro	OR				Not Determined by State (at this time)
eBay - Solar	[redacted]	[redacted]	10.0	0.52	[redacted]	Solar	UT				QF
EBD Hydro	[redacted]	[redacted]	15.0	2.99	[redacted]	Hydro	OR				QF
Evergreen BioPower	[redacted]	[redacted]	11.0	10.00	[redacted]	Biomass	OR				QF
ExxonMobile Production Company	[redacted]	[redacted]	7.0	107.40	[redacted]	Natural Gas	WY				QF
Falls Creek	[redacted]	[redacted]	33.6	4.10	[redacted]	Hydro	OR				QF
Farm Power Misty Meadow	[redacted]	[redacted]	15.5	0.75	[redacted]	Biogas	OR				QF
Farmers Irrigation	[redacted]	[redacted]	27.5	4.15	[redacted]	Hydro	OR				Not Determined by State (at this time)
Farmers Irrigation (renewal)	[redacted]	[redacted]	15.0	4.15	[redacted]	Hydro	OR				QF
Finley Bioenergy	[redacted]	[redacted]	15.1	4.80	[redacted]	Biogas	OR				QF

Plant Name	Entitlement Start Date	Entitlement End Date	Term (Years)	Nameplate or Contract Capacity (MW)	2011 Average Output (aMW)	Resource Type	State	CA (see Note 1)	OR	WA	REC Entitlement (PacifiCorp, QF or Not Determined by State (at this time) (see Note 2))
Four Corners Windfarm LLC	[redacted]	[redacted]	20.1	10.00	[redacted]	Wind	OR				QF
Four Mile Canyon Windfarm LLC	[redacted]	[redacted]	20.1	10.00	[redacted]	Wind	OR				QF
Galesville Dam (Douglas County)	[redacted]	[redacted]	39.4	1.80	[redacted]	Hydro	OR				Not Determined by State (at this time)
Garland Canal (Shoshone)	[redacted]	[redacted]	19.7	3.00	[redacted]	Hydro	WY				Not Determined by State (at this time)
Georgetown Power	[redacted]	[redacted]	36.8	0.33	[redacted]	Hydro	ID				Not Determined by State (at this time)
GroPro, Inc.	[redacted]	[redacted]	4.8	0.01	[redacted]	Biomass	CA				PacifiCorp
High Plateau Windfarm LLC	[redacted]	[redacted]	21.0	10.00	[redacted]	Wind	OR				QF
Hill Air Force Base	[redacted]	[redacted]	20.0	2.46	[redacted]	Biogas	UT	60789A	11lfg004ut, 11lfg005ut		Not Determined by State (at this time)
Ingram Warm Springs Ranch	[redacted]	[redacted]	35.0	0.95	[redacted]	Hydro	ID				Not Determined by State (at this time)
J Bar 9 Ranch	[redacted]	[redacted]	5.2	0.10	[redacted]	Wind	WY	61675C	12wnd012wy		PacifiCorp
Jim & Sharon Jans (Odell Creek)	[redacted]	[redacted]	27.3	0.23	[redacted]	Hydro	OR				Not Determined by State (at this time)
Jim & Sharon Jans (Odell Creek) (renewal)	[redacted]	[redacted]	15.0	0.23	[redacted]	Hydro	OR				QF
Kennecott Refinery	[redacted]	[redacted]	1.0	7.54	[redacted]	Waste Heat	UT				QF
Kennecott Refinery (renewal)	[redacted]	[redacted]	1.0	7.54	[redacted]	Waste Heat	UT				QF
Kennecott Refinery (renewal)	[redacted]	[redacted]	1.0	7.54	[redacted]	Waste Heat	UT				QF
Kennecott Smelter	[redacted]	[redacted]	1.2	31.80	[redacted]	Waste Heat	UT				Not Determined by State (at this time)
Kennecott Smelter (renewal)	[redacted]	[redacted]	1.0	31.80	[redacted]	Waste Heat	UT				Not Determined by State (at this time)
Kennecott Smelter (renewal)	[redacted]	[redacted]	1.0	31.80	[redacted]	Waste Heat	UT				Not Determined by State (at this time)
Kennecott Smelter (renewal)	[redacted]	[redacted]	1.0	31.80	[redacted]	Waste Heat	UT				Not Determined by State (at this time)
Kennecott Smelter (renewal)	[redacted]	[redacted]	1.0	31.80	[redacted]	Waste Heat	UT				Not Determined by State (at this time)
Kennecott Smelter (renewal)	[redacted]	[redacted]	1.0	31.80	[redacted]	Waste Heat	UT				Not Determined by State (at this time)
Kennecott Smelter (renewal)	[redacted]	[redacted]	1.0	31.80	[redacted]	Waste Heat	UT				Not Determined by State (at this time)
Kennecott Smelter (renewal)	[redacted]	[redacted]	1.0	31.80	[redacted]	Waste Heat	UT				Not Determined by State (at this time)
Kennecott Smelter (renewal)	[redacted]	[redacted]	1.0	31.80	[redacted]	Waste Heat	UT				Not Determined by State (at this time)
Lacomb Irrigation	[redacted]	[redacted]	33.3	0.96	[redacted]	Hydro	OR				Not Determined by State (at this time)
Lacomb Irrigation (Lacomb PPA Renegotiated) (renewal)	[redacted]	[redacted]	24.6	0.96	[redacted]	Hydro	OR				Not Determined by State (at this time)
Lake Siskiyou (Box Canyon)	[redacted]	[redacted]	37.8	5.00	[redacted]	Hydro	CA	60778E			PacifiCorp
Lower Ridge Windfarm LLC	[redacted]	[redacted]	21.0	10.00	[redacted]	Wind	OR				QF
Lower Valley Energy	[redacted]	[redacted]	5.1	1.70	[redacted]	Hydro	WY				Not Determined by State (at this time)
Loyd Fery	[redacted]	[redacted]	18.5	0.04	[redacted]	Hydro	OR				Not Determined by State (at this time)
Loyd Fery (renewal)	[redacted]	[redacted]	1.0	0.04	[redacted]	Hydro	OR				Not Determined by State (at this time)
Loyd Fery (renewal)	[redacted]	[redacted]	1.0	0.04	[redacted]	Hydro	OR				Not Determined by State (at this time)
Loyd Fery (renewal)	[redacted]	[redacted]	1.0	0.04	[redacted]	Hydro	OR				Not Determined by State (at this time)
Loyd Fery (renewal)	[redacted]	[redacted]	1.0	0.04	[redacted]	Hydro	OR				Not Determined by State (at this time)
Loyd Fery (renewal)	[redacted]	[redacted]	6.0	0.04	[redacted]	Hydro	OR				QF
Luckey, Paul	[redacted]	[redacted]	30.7	0.05	[redacted]	Hydro	CA	60782E			PacifiCorp
Magnesium Corporation of America	[redacted]	[redacted]	5.0	36.00	[redacted]	Natural Gas	UT				QF
Magnesium Corporation of America (renewal)	[redacted]	[redacted]	1.0	36.00	[redacted]	Natural Gas	UT				QF
Magnesium Corporation of America (renewal)	[redacted]	[redacted]	1.0	36.00	[redacted]	Natural Gas	UT				QF
Magnesium Corporation of America (renewal)	[redacted]	[redacted]	1.0	36.00	[redacted]	Natural Gas	UT				QF
Marsh Valley Hydro & Electric Company	[redacted]	[redacted]	41.4	1.70	[redacted]	Hydro	ID				Not Determined by State (at this time)
Meadow Creek Project Company - Five Pine	[redacted]	[redacted]	20.0	40.00	[redacted]	Wind	ID				PacifiCorp
Meadow Creek Project Company - North Point	[redacted]	[redacted]	20.0	80.00	[redacted]	Wind	ID				PacifiCorp
Middlefork Irrigation District	[redacted]	[redacted]	22.3	3.70	[redacted]	Hydro	OR				Not Determined by State (at this time)
Middlefork Irrigation District (renewal)	[redacted]	[redacted]	16.0	3.70	[redacted]	Hydro	OR				QF
Mink Creek Hydro	[redacted]	[redacted]	36.9	2.70	[redacted]	Hydro	ID				Not Determined by State (at this time)
Monroe Hydro	[redacted]	[redacted]	15.0	0.30	[redacted]	Hydro	OR				QF
Mountain Energy	[redacted]	[redacted]	19.6	0.05	[redacted]	Hydro	OR				Not Determined by State (at this time)
Mountain Energy (renewal)	[redacted]	[redacted]	1.0	0.05	[redacted]	Hydro	OR				Not Determined by State (at this time)
Mountain Energy (renewal)	[redacted]	[redacted]	1.0	0.05	[redacted]	Hydro	OR				Not Determined by State (at this time)
Mountain Energy (renewal)	[redacted]	[redacted]	1.0	0.05	[redacted]	Hydro	OR				Not Determined by State (at this time)
Mountain Energy (renewal)	[redacted]	[redacted]	15.0	0.05	[redacted]	Hydro	OR				QF
Mountain Wind 1	[redacted]	[redacted]	25.0	60.90	[redacted]	Wind	WY	60811A	09wnd011wy		PacifiCorp
Mountain Wind 2	[redacted]	[redacted]	25.0	79.80	[redacted]	Wind	WY	60812A	09wnd012wy		PacifiCorp
Mule Hollow Windfarm LLC	[redacted]	[redacted]	21.0	10.00	[redacted]	Wind	OR				QF
Nicholson Sunnybar Ranch	[redacted]	[redacted]	35.9	0.35	[redacted]	Hydro	ID				Not Determined by State (at this time)
O.J. Power Company	[redacted]	[redacted]	35.9	0.26	[redacted]	Hydro	ID				Not Determined by State (at this time)
OM Power I	[redacted]	[redacted]	14.6	10.00	[redacted]	Geothermal Steam	OR				QF
Oregon Environmental Industries	[redacted]	[redacted]	14.9	3.20	[redacted]	Biogas	OR				QF
Oregon Institute of Technology	[redacted]	[redacted]	20.0	0.28	[redacted]	Geothermal Steam	OR				QF
Oregon State University	[redacted]	[redacted]	9.6	6.50	[redacted]	Natural Gas	OR				QF
Oregon Trail Windfarm LLC	[redacted]	[redacted]	20.1	9.90	[redacted]	Wind	OR				QF
Pacific Canyon Windfarm LLC	[redacted]	[redacted]	20.1	8.25	[redacted]	Wind	OR				QF
Pine City Windfarm LLC	[redacted]	[redacted]	21.0	10.00	[redacted]	Wind	OR				QF
Power County Wind Park North	[redacted]	[redacted]	20.0	22.50	[redacted]	Wind	ID				Not Determined by State (at this time)
Power County Wind Park South	[redacted]	[redacted]	20.0	22.50	[redacted]	Wind	ID				Not Determined by State (at this time)

Plant Name	Entitlement Start Date	Entitlement End Date	Term (Years)	Nameplate or Contract Capacity (MW)	2011 Average Output (aMW)	Resource Type	State	CA (see Note 1)	OR	WA	REC Entitlement (PacifiCorp, QF or Not Determined by State (at this time) (see Note 2))
Preston City Hydro	[redacted]	[redacted]	35.9	0.40	[redacted]	Hydro	ID				Not Determined by State (at this time)
Ralphs Ranch, Inc	[redacted]	[redacted]	30.4	0.10	[redacted]	Hydro	CA	60779E			Not Determined by State (at this time)
RES Ag- Oak Lea	[redacted]	[redacted]	15.0	0.17	[redacted]	Biogas	OR				QF
Roseburg Forest Products - Dillard	[redacted]	[redacted]	7.4	20.00	[redacted]	Biomass	OR	60510A			QF
Roseburg Forest Products - Weed	[redacted]	[redacted]	0.3	10.00	[redacted]	Biomass	CA	60501A			PacifiCorp
Roseburg Forest Products - Weed (renewal)	[redacted]	[redacted]	0.3	10.00	[redacted]	Biomass	CA				PacifiCorp
Roseburg Forest Products - Weed (renewal)	[redacted]	[redacted]	0.5	10.00	[redacted]	Biomass	CA				PacifiCorp
Roseburg Forest Products - Weed (renewal)	[redacted]	[redacted]	0.5	10.00	[redacted]	Biomass	CA				PacifiCorp
Roseburg Forest Products - Weed (renewal)	[redacted]	[redacted]	6.0	10.00	[redacted]	Biomass	CA				PacifiCorp
Roseburg LFG	[redacted]	[redacted]	20.9	1.60	[redacted]	Biogas	OR				QF
Rough & Ready Lumber	[redacted]	[redacted]	5.1	1.28	[redacted]	Biomass	OR				QF
Rough & Ready Lumber (renewal)	[redacted]	[redacted]	6.0	1.28	[redacted]	Biomass	OR				QF
Roush Hydro, Inc	[redacted]	[redacted]	20.0	0.08	[redacted]	Hydro	OR				QF
Roush Hydro, Inc (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				Not Determined by State (at this time)
Roush Hydro, Inc (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				Not Determined by State (at this time)
Roush Hydro, Inc (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				Not Determined by State (at this time)
Roush Hydro, Inc (renewal)	[redacted]	[redacted]	1.0	0.08	[redacted]	Hydro	OR				Not Determined by State (at this time)
Roush Hydro, Inc (renewal)	[redacted]	[redacted]	6.0	0.08	[redacted]	Hydro	OR				QF
Sand Ranch Windfarm LLC	[redacted]	[redacted]	20.1	9.90	[redacted]	Wind	OR				QF
Santiam Hydro Control District	[redacted]	[redacted]	36.3	0.16	[redacted]	Hydro	OR				Not Determined by State (at this time)
Simplot Phosphates, LLC	[redacted]	[redacted]	7.0	9.50	[redacted]	Waste Heat	WY				QF
Slate Creek	[redacted]	[redacted]	37.0	4.20	[redacted]	Hydro	CA	60777E			Not Determined by State (at this time)
Spanish Fork Wind Park 2	[redacted]	[redacted]	20.0	18.90	[redacted]	Wind	UT				QF
Sprague Hydro (North Fork Sprague)	[redacted]	[redacted]	38.3	0.75	[redacted]	Hydro	OR				Not Determined by State (at this time)
St. Anthony	[redacted]	[redacted]	20.0	0.50	[redacted]	Hydro	ID	60800E			PacifiCorp
Stahlbush Island Farms	[redacted]	[redacted]	2.1	1.60	[redacted]	Biogas	OR				QF
Stahlbush Island Farms (renewal)	[redacted]	[redacted]	3.0	1.60	[redacted]	Biogas	OR				QF
Sunnyside Cogeneration Associates	[redacted]	[redacted]	30.0	53.00	[redacted]	Coal	UT				QF
Swalley Irrigation District	[redacted]	[redacted]	20.2	0.75	[redacted]	Hydro	OR				QF
Tesoro Refining and Marketing Company	[redacted]	[redacted]	1.3	25.00	[redacted]	Natural Gas	UT				QF
Tesoro Refining and Marketing Company (renewal)	[redacted]	[redacted]	1.0	25.00	[redacted]	Natural Gas	UT				QF
Tesoro Refining and Marketing Company (renewal)	[redacted]	[redacted]	1.0	25.00	[redacted]	Natural Gas	UT				QF
Tesoro Refining and Marketing Company (renewal)	[redacted]	[redacted]	1.0	25.00	[redacted]	Natural Gas	UT				QF
Tesoro Refining and Marketing Company (renewal)	[redacted]	[redacted]	1.0	25.00	[redacted]	Natural Gas	UT				QF
Tesoro Refining and Marketing Company (renewal)	[redacted]	[redacted]	1.0	25.00	[redacted]	Natural Gas	UT				QF
Tesoro Refining and Marketing Company (renewal)	[redacted]	[redacted]	1.0	25.00	[redacted]	Natural Gas	UT				QF
Tesoro Refining and Marketing Company (renewal)	[redacted]	[redacted]	1.0	25.00	[redacted]	Natural Gas	UT				QF
Tesoro Refining and Marketing Company (renewal)	[redacted]	[redacted]	1.0	25.00	[redacted]	Natural Gas	UT				QF
Thayn Ranch Hydro	[redacted]	[redacted]	23.8	0.48	[redacted]	Hydro	UT				QF
Threemile Canyon Wind I LLC	[redacted]	[redacted]	0.3	9.90	[redacted]	Wind	OR				QF
Threemile Canyon Wind I LLC (renewal)	[redacted]	[redacted]	0.1	9.90	[redacted]	Wind	OR				QF
Threemile Canyon Wind I LLC (renewal)	[redacted]	[redacted]	0.1	9.90	[redacted]	Wind	OR				QF
Threemile Canyon Wind I LLC (renewal)	[redacted]	[redacted]	0.4	9.90	[redacted]	Wind	OR				QF
Threemile Canyon Wind I LLC (renewal)	[redacted]	[redacted]	0.5	9.90	[redacted]	Wind	OR				QF
Threemile Canyon Wind I LLC (renewal)	[redacted]	[redacted]	0.4	9.90	[redacted]	Wind	OR				QF
Threemile Canyon Wind I LLC (renewal)	[redacted]	[redacted]	0.3	9.90	[redacted]	Wind	OR				QF
Threemile Canyon Wind I LLC (renewal)	[redacted]	[redacted]	0.5	9.90	[redacted]	Wind	OR				QF
Threemile Canyon Wind I LLC (renewal)	[redacted]	[redacted]	0.5	9.90	[redacted]	Wind	OR				QF
Threemile Canyon Wind I LLC (renewal)	[redacted]	[redacted]	1.0	9.90	[redacted]	Wind	OR				QF
TMF Biofuels	[redacted]	[redacted]	11.2	4.80	[redacted]	Biogas	OR				QF
Wagon Trail LLC	[redacted]	[redacted]	20.1	3.30	[redacted]	Wind	OR				QF
Walla Walla, City of	[redacted]	[redacted]	28.5	2.00	[redacted]	Hydro	WA				Not Determined by State (at this time)
Ward Butte Windfarm LLC	[redacted]	[redacted]	20.1	6.60	[redacted]	Wind	OR				QF
Wasatch Integrated Waste Management District	[redacted]	[redacted]	19.8	1.60	[redacted]	Biogas	UT				Not Determined by State (at this time)
Wasatch Integrated Waste Management District (renewal)	[redacted]	[redacted]	11.0	1.60	[redacted]	Biogas	UT				QF
Weber County, State of Utah	[redacted]	[redacted]	19.0	0.95	[redacted]	Biogas	UT				Not Determined by State (at this time)
Yakima Tieton (Cowiche)	[redacted]	[redacted]	20.6	1.47	[redacted]	Hydro	WA				Not Determined by State (at this time)
Yakima Tieton (Cowiche) (renewal)	[redacted]	[redacted]	3.0	1.47	[redacted]	Hydro	WA				Not Determined by State (at this time)
Yakima Tieton (Cowiche) (renewal)	[redacted]	[redacted]	3.0	1.47	[redacted]	Hydro	WA				Not Determined by State (at this time)
Yakima Tieton (Cowiche) (renewal)	[redacted]	[redacted]	1.0	1.47	[redacted]	Hydro	WA				QF
Yakima Tieton (Cowiche) (renewal)	[redacted]	[redacted]	3.0	1.47	[redacted]	Hydro	WA				QF
Yakima Tieton (Orchards)	[redacted]	[redacted]	20.6	1.47	[redacted]	Hydro	WA				Not Determined by State (at this time)
Yakima Tieton (Orchards) (renewal)	[redacted]	[redacted]	3.0	1.47	[redacted]	Hydro	WA				Not Determined by State (at this time)
Yakima Tieton (Orchards) (renewal)	[redacted]	[redacted]	3.0	1.47	[redacted]	Hydro	WA				Not Determined by State (at this time)
Yakima Tieton (Orchards) (renewal)	[redacted]	[redacted]	1.0	1.47	[redacted]	Hydro	WA				QF
Yakima Tieton (Orchards) (renewal)	[redacted]	[redacted]	3.0	1.47	[redacted]	Hydro	WA				QF

Plant Name	Entitlement Start Date	Entitlement End Date	Term (Years)	Nameplate or Contract Capacity (MW)	2011 Average Output (aMW)	Resource Type	State	CA (see Note 1)	OR (see Note 1)	WA (see Note 1)	REC Entitlement (PacifiCorp, QF or Not Determined by State (at this time) (see Note 2))

Note 1 The determination of whether a facility qualifies for state renewable portfolio standards (RPS) and can be used by PacifiCorp for the purposes of meeting state RPS requirements is under the jurisdiction of the California Energy Commission (CEC), the Oregon Department of Energy (ODOE), or the Washington Utilities and Transportation Commission (WUTC). PacifiCorp has provided the certification numbers for the facilities that PacifiCorp has submitted application, and received certification from the various regulatory agencies. PacifiCorp does not track the certification of a facility's eligibility if PacifiCorp does not retain the rights to the renewable energy certificates (REC).

Note 2 "Not Determined by State - at this time" means that the utility commission and/or regulatory agency of the state in which the project is located has not issued a formal decision or order with regard to REC entitlement (at this time).

UM 1610/PacifiCorp
February 25, 2013
REC Data Request 2.16

REC Data Request 2.16

Regarding PAC/100, Dickman/21, has the Company ever requested that any of the documentation in the official forward price curve be considered highly confidential?

Response to REC Data Request 2.16

Yes, the Company has requested that portions of the documentation in the official forward price curve (OFPC) be considered highly confidential.

UM 1610/PacifiCorp
February 25, 2013
REC Data Request 2.22

REC Data Request 2.22

Regarding PAC/200, Griswold/17, please provide the same information for non-wind QFs.

Response to REC Data Request 2.22

Please refer to Attachment REC 2.22.

	Nameplate Categories							
	<= 3 MW		3 to 10 MW		> 10 MW		QF TOTAL	
Resource Type	**#**	**Total MW**	**#**	**Total MW**	**#**	**Total MW**	**#**	**Total MW**
Biogas	5	7.1	3	12.8			8	19.9
Biomass (1)	1	1.3	2	16.3			3	17.5
Geothermal (2)	1	0.3	1	10.0			2	10.3
Hydro (3)	7	5.7	3	21.1			10	26.8
Natural Gas			1	6.5			1	6.5
Wind (4)	1	1.7	14	112.8			15	114.5
TOTAL	**15**	**16.0**	**24**	**179.5**			**39**	**195.5**

Notes
(1) Biomass has 1 - 10 MW project
(2) Geothermal has 1 - 10 MW project
(3) Hydro has 1 - 10 MW project
(4) Wind has 3 - 9.9 MW and 6 - 10 MW projects

UM 1610/PacifiCorp
February 25, 2013
REC Data Request 2.23

REC Data Request 2.23

Regarding PAC/200, Griswold/21-26, please identify which the Company's concerns apply to non-wind QFs.

Response to REC Data Request 2.23

The Company has the same disaggregation concerns as they apply to solar photovoltaic projects.

UM 1610/PacifiCorp
February 25, 2013
REC Data Request 2.24

REC Data Request 2.24

For non-standard QFs, does PacifiCorp agree that is should not make adjustments to avoided cost rates other than those approved by the Oregon PUC?

Response to REC Data Request 2.24

Yes. Adjustments to avoided cost rates should be made consistent with the methodology approved by the Oregon Public Utility Commission.

UM 1610/PacifiCorp
February 25, 2013
REC Data Request 2.27

REC Data Request 2.27

Since 2000, please identify for each QF the length of time to complete the interconnection process, including the date of initial contact by the QF, the date of formal request for interconnection, the date the interconnection agreement was finalized, and the date the interconnection was finished.

Response to REC Data Request 2.27

Please refer to Attachment REC 2.27 for a qualifying facilities (QF) timeline, which shows that, on average, it takes two-plus years from the time of application to reach commercial operations for QFs in the state of Oregon. There were no qualifying facility customer applications prior to June 2005.

Qualified Facility Timeline

Queue #	Company Name	Application Date	IA Signed	COD	Total Length (Days)	Total Length (Years)
56	Evergreen BioPower LLC [Freres Lumber]	6/30/2005	10/19/2006	10/17/2007	839	2.30
71	Threemile Canyon Wind, LLC	1/17/2006	7/15/2008	7/15/2009	1275	3.49
97	Rough & Ready Lumber	10/16/2006	6/26/2007	2/18/2008	490	1.34
99	Meduri Farms, Inc.	10/20/2006	10/15/2007	N/A		
102-106, 145-147	Exelon Wind, LLC	11/7/2006	10/22/2008	1/20/2010	1170	3.20
108	Cameron A. Curtiss	11/28/2006	11/19/2007	8/18/2008	629	1.72
141	Swalley Irrigation District	6/12/2007	9/18/2008	5/14/2010	1067	2.92
151	Biomass One, LP	7/16/2007	9/17/2008	2/3/2009	568	1.56
170	Roush Hydro, Inc.	11/8/2007	1/11/2013	1/11/2013	1891	5.18
174	Oregon State University	12/5/2007	6/24/2009	7/9/2010	947	2.59
176	Stahlbush Island Farms, Inc.	12/26/2007	10/1/2008	6/17/2009	539	1.48
248	Central Oregon Irrigation District	11/14/2008	2/1/2010	10/11/2010	696	1.91
251	Oregon Institute of Technology	11/20/2008	7/31/2009	1/6/2010	412	1.13
279	Farmers Irrigation District	6/30/2009	11/24/2010	1/25/2011	574	1.57
283	Duane Wiggins Hydro	8/17/2009	2/15/2010	11/1/2010	441	1.21
296	City of Portland Water Bureau	10/5/2009	11/2/2010	9/10/2012	1071	2.93
299	C-Drop Hydro, LLC (fka Klamath Irrigation District)	10/13/2009	7/18/2011	4/27/2012	927	2.54
303	RES Agriculture, LLC	11/13/2009	9/8/2010	2/20/2012	829	2.27
355	Mountain Energy Inc.	11/1/2010	3/3/2011	4/29/2011	179	0.49
358	Odell Creek Hydro	11/4/2010	2/8/2011	2/8/2011	96	0.26
360	TMF Biofuels, LLC	11/11/2010	9/1/2011	-		
366	Roseburg LFG Energy, LLC	12/22/2010	8/12/2011	11/23/2011	336	0.92
					748.8	2.05

UM 1610/PacifiCorp
March 12, 2013
REC Data Request 3.1

REC Data Request 3.1

Since 2005, please identify the resource sufficiency/deficiency period in the Company's avoided cost rates.

Response to REC Data Request 3.1

Please refer to the table below:

Year	Deficit Year
2005	2010
2006	2010
2007	2012
2008	2012
2009	2014
2010	2014
2011	2014
2012	2016
2013	2016

UM 1610/PacifiCorp
March 12, 2013
REC Data Request 3.2

REC Data Request 3.2

Since 2005, please identify all resource acquisitions of 25 MWs or greater that occurred during the Company's resource sufficiency period.

Response to REC Data Request 3.2

Owned Resources

Chehalis
Dunlap 1
Glenrock 1
Glenrock 3
Goodnoe Hills
High Plains
Lake Side II
Leaning Juniper
Marengo 1
Marengo 2
McFadden Ridge 1
Rolling Hills
Seven Mile Hill 1

Contracted Resources

Exxon Mobil
Meadow Creek Project – North Point
Meadow Creek Project – Five Pine
Mountain Wind 1
Mountain Wind 2
Three Buttes Windpower
Top of the World Wind
Wolverine Creek

UM 1610/PacifiCorp
March 12, 2013
REC Data Request 3.4

REC Data Request 3.4

Under PacifiCorp's proposal regarding legally enforceable obligation, at what point in time in the negotiations under Schedule 37 will the avoided cost rates no longer be subject to revision or modification?

Response to REC Data Request 3.4

The Company recognizes that the issue of a legally enforceable obligation involves many legal questions however, for the negotiation process, the legally enforceable obligation is established, at which point in time the avoided cost prices as contained in the final draft power purchase agreement (PPA) are no longer subject to revision or modification, at the milestone of the qualifying facility (QF) approving the final draft PPA as contemplated in section B(5) on page 10 of Schedule 37.

UM 1610/PacifiCorp
March 12, 2013
REC Data Request 3.5

REC Data Request 3.5

Under PacifiCorp's proposed PDDRR method, please state whether a renewable QF above the size threshold will retain the renewable energy credits.

Response to REC Data Request 3.5

Under the proposed Partial Displacement Differential Revenue Requirement (PDDRR) method, a renewable qualifying facility (QF) would retain the renewable energy credits because the proxy resource is a non-renewable resource.

UM 1610/PacifiCorp
November 19, 2012
OPUC Data Request 2

OPUC Data Request 2

If PURPA and federal regulations allow allocation of incremental integration costs to the QF, would it be practical to assign those costs to the interconnection charge rather than the avoided cost price? If not, please explain why not.

Response to OPUC Data Request 2

No. Assigning integration costs to the interconnection costs would not be practical because the integration charge would be administrated by the Company's merchant function while the interconnection process is administered by the Company's transmission function.

UM 1610/PacifiCorp
November 19, 2012
OPUC Data Request 5

OPUC Data Request 5

Schedule 37 states that when both parties are in full agreement as to all terms and conditions of the draft Standard Contract, the Company will prepare and forward to the Seller a final executable version of the agreement. How does the Company determine the date when full agreement has been reached?

Response to OPUC Data Request 5

The Company determines the date when full agreement has been reached being when the qualifying facility (QF) and PacifiCorp mutually agree (either in writing or by telephone), that all terms and conditions, requirements under Schedule 37, and milestones are complete and final.

January 28, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Data Request No. 003
Dated January 11, 2013

Request:

In Oregon since 2000, please identify the date of each filing to change its avoided cost rates.

Response:

ADVICE NO.	FILED	EFFECTIVE
99-17	12/21/99	02/09/00
00-15	11/01/00	01/01/01
01-01	02/16/01	04/04/01
00-14A	09/14/01	10/01/01
02-07	02/22/02	04/24/02
02-28	12/17/02	02/05/03
03-19	10/22/03	12/05/03
04-03	01/16/04	03/03/04
05-10	07/12/05	08/11/05
06-26	03/06/07	03/07/07
07-01	01/16/07	01/17/07
07-17	07/13/07	08/13/07
07-27	11/01/07	11/02/07
09-16	07/10/09	09/09/09
10-27	12/20/10	01/19/11
N/A	12/20/12	01/19/13

N/A = Not Applicable

January 28, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Data Request No. 004
Dated January 11, 2013

Request:

In Oregon since 2005, please identify the date for order acknowledging or not acknowledging each integrated resource plan.

Response:

Since 2005, PGE has filed a 2007 and 2009 Integrated Resource Plan (IRP). On May 6, 2008, per Commission Order No. 08-246, PGE's 2007 IRP was not acknowledged and was ordered to submit a new plan within 18 months of the effective date of the order. On November 23, 2010, per Commission Order No. 10-457, PGE's 2009 IRP was acknowledged.

February 25, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Data Request No. 006
Dated February 11, 2013

Request:

Regarding PGE response to REC DR 1.2, please confirm that the response identifies all QF contracts that the Company has ever entered into. If not, please provide a supplemental response including all the Company's QFs contracts that it has entered into (existing and expired). Please identify which QF contracts were not renewed.

Response:

PGE did not understand the original request (DR 1.2) to include expired contracts. The table has been updated to the best of PGE's knowledge. Attachment 006-A provides all the information that is readily available.

UM 1610

Attachment 006-A

Provided in Electronic Format (CD) Only

PGE's QF Contracts

A	B		B-C	D		E	F	G	H	
QF Name	Contract Effective Date	Contract End Date	Existing Contract / New Contract / Renewed Contract / Other	Capacity (MW)	11 Generation (MW	Type	Location	State Standard*	Who Retains RECs?	Standard?
Covanta Marion	1984	2014	Original Term	13	87,181	Waste	Salem, OR	Unknown	Seller	No
PaTu Wind	2010	2030	Original Term	10	39,734	Wind	Wasco, OR	Oregon	Seller	Yes
City of Portland	1984	2014	Original Term	<1	0	Hydro	Portland, C	Unknown	Seller	No
Lake Oswego Corporation	1961	Evergreen	Original Term	<1	97	Hydro	Lake Oswe	Unknown	Seller	No
Country Village Estates	2011	2015	Original Term	<1	6	Solar	??	Unknown	Seller	Yes
Douglas Pegar	1985	2003	purchasing under tariff	<1	278	Hydro	Mt. Hood a	Unknown	Seller	No
Domaine Drouhin	2008	Evergreen	Original Term	<1	102	Hydro	Small Gene	Unknown	Seller	Yes
Von Land Co	1985	2012	renewed 2009; currently purchasing under tariff	<1	228	Hydro	Mt. Hood a	Unknown	Seller	Yes
Minikahada Hydropower Co	1985	2013	renewed	<1	367	Hydro	Mt. Hood a	Unknown	Seller	Yes
SunWay II	2009	2028	Original Term	1.1	2,967	Solar	Portland, C	Oregon	Seller	Yes
SunWay III	2010	2029	Original Term	2.4		Solar	Portland, C	Oregon	Seller	Yes
Tualatin Valley Water Dist	1985	Evergreen	purchasing under tariff	<1	108	Hydro	??	Unknown	Seller	No
Starbuck Properties LLC	2008	Evergreen	Original Term	<1	24	Solar	??	Oregon	Seller	Yes
Power Resources Coop.	2012	2027	Original Term as PGE QF / resource came on line in 1995	5.66	0	biogas	Eugene, OF	Unknown	Seller	Yes
North Wasco PUD	2012	2015	Original Term as PGE QF / resource came on line in 1991	5.8	0	Hydro	The Dalles,	Unknown	Seller	Yes
Green Lane	2011	2031	New Resource to begin delivery in 2013	1.6	0	biogas	??	Unknown	Seller	Yes
Lucid Energy	2012	2032	New Contract	<1	0	Hydro	Portland, C	Unknown	Seller	Yes
City of Gresham	2012	2032	New Contract	<1	0	Hydro	Portland, C	Unknown	Seller	Yes
Forest Glenn Oaks	2012	2032	New Contract	<1	0	biogas	McMinnvill	Unknown	Seller	Yes
Douglas R Boleyn	1998	1999		<1	0			Unknown		No
Jane Horning	1998	2003		<1	0	Hydro	Cornelius, (	Unknown		No
Nature Conservancy	1998			<1	0	Solar	Portland, C	Unknown		No
World Trade Center Bldg 3	1998			<1	0	Solar	Portland, C	Unknown		No
Value Cad	1998			<1	0	Solar	Portland, C	Unknown		No
Robert Migliori	1998	2000		<1	0	Wind	Newberg, (	Unknown		No
Robert Migliori	2002	2003			0			Unknown		No
Mission Mill Museum	1998			<1	0	Water Whe	Salem, OR	Unknown		No
Raleigh Water Dist	1998	2003		<1	0	Hydro	Portland, C	Unknown		No
Tualatin Valley Mental	1999	2005			0			Unknown		No
Kinzua	1985	1994	Original Term 1985-2005/Terminated by mutual Agreement 1994		0	biomass		Unknown		No

Sunway II and III are PGE projects
*Information is not readily available

Coalition/102
Lowe/28

February 25, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Data Request No. 010
Dated February 11, 2013

Request:

Regarding, PGE/100, Macfarlane-Morton/11, please state whether the QF owner can sell the RECs in another state during the renewable resource sufficiency period, and whether Order No. 11-505 allows the QF to sell RECs in another state during the renewable resource sufficiency period.

Response:

PGE objects to this request as it calls for legal analysis of an order which the requesting party may read for themselves. Without waiving its objection, PGE responds as follows:

In UM 1396 Order No. 11-505 the Commission holds that QFs are able to choose between two avoided cost streams, and that "Renewable QFs willing to sell their output and cede their RECs to the utility allow the utility to avoid building (or buying) renewable generation to meet their RPS requirements. These QFs should be offered an avoided cost stream that reflects the costs that the utility will avoid."

Further, the Commission states that "during the renewable resource sufficiency period the QF should be paid the market price and retain its RECs."

As stated on page 11 of PGE's direct testimony (Exhibit 100) in UM 1610, our recommendation is that the policy articulated in Order No. 11-505 be continued. Order No. 11-505 states that if the renewable avoided cost rate is not paid, the REC is retained by the renewable energy facility, but the Order does not specifically articulate whether or not those RECs can be sold in another state.

y:\ratecase\opuc\dockets\um-1610 (investigation into qfc & p)\dr-in\rec\finals\dr_010.docx

February 25, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Data Request No. 013
Dated February 11, 2013

Request:

Regarding, PGE/100, Macfarlane-Morton/21-22, please identify the specific methodology that PGE proposes to use for each of the FERC factors identified.

Response:

PGE does not propose any specific methodology be used for the FERC Adjustment Factors. Rather, determinations are made on a case-by-case basis and adjustments reflect overall contract risk, a holistic examination of characteristics of the QF, and the terms of the agreement. This flexibility would better accommodate the wide variety of projects that approach PGE.

February 25, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Data Request No. 014
Dated February 11, 2013

Request:

Regarding, PGE/100, Macfarlane-Morton/21-22, please explain how PGE would adjust the avoided cost rates for the terms of the contract, the duration of the obligation, termination notice provisions and sanctions for non-compliance.

Response:

Please see PGE's Response to REC Data Request No. 013.

February 25, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Data Request No. 015
Dated February 11, 2013

Request:

Regarding, PGE/100, Macfarlane-Morton/21-22, please explain how the PGE standard contract does not address issues related to default, damages and termination, including issues related to the terms of the contract, the duration of the obligation, termination notice provisions and sanctions for non-compliance.

Response:

PGE's cited testimony does not suggest that standard contracts do not address these issues; rather, there are terms that cover these items. The standard contract as currently implemented by the Commission does not allow for adjustment to avoided cost for these factors.

February 25, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Data Request No. 018
Dated February 11, 2013

Request:

For non-standard QFs, does PGE agree that is should not make adjustments to avoided cost rates other than those approved by the Oregon PUC?

Response:

PGE objects to this data request as it calls for a legal conclusion and is not reasonably calculated to lead to the discovery of admissible evidence.

February 25, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Data Request No. 019
Dated February 11, 2013

Request:

Regarding, PGE/100, Macfarlane-Morton/23, please identify for each QF the length of time to complete the interconnection process, including the date of initial contact by the QF, the date of formal request for interconnection, the date the interconnection agreement was finalized, and the date the interconnection was finished.

Response:

The Division 82 rules are used as a process outline for interconnections with a few possible exceptions. PGE does not keep interconnection timelines for older QFs; the following information is what is kept by PGE on newer QF interconnections.

QF	Date of Initial Contact by QF	Date Interconnection agreement was finalized	Date interconnection was finished (system online)
Country Village	10/8/2010	11/16/2010	10/4/2011*
Starbuck Properties	7/15/2010	11/16/2010	11/18/2010

*Delay was due to customer time to build interconnection facilities, not PGE delay

March 12, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Third Set of Data Request No. 020
Dated February 26, 2013

Request:

Please review Guideline 8 in Order 07-360, in Docket No. UM 1129. Is PGE proposing that this Guideline be changed?

Response:

Guideline 8 in Order No. 07-360 states: " [T]he utility should not make adjustments to standard avoided cost rates other than those approved by the Oregon Commission and consistent with these guidelines." PGE assumes the Oregon Commission will issue an order in this UM 1610 docket approving which adjustments to standard avoided cost rates may be made; PGE is not proposing that this Guideline be changed. See PGE Testimony Macfarlane/Morton 19-22 for PGE's proposal regarding adjustments to standard contracts.

March 12, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Third Set of Data Request No. 022
Dated February 26, 2013

Request:

Since 2005, please identify the resource sufficiency/deficiency period in the Company's avoided cost rates.

Response:

Effective Date	Sufficiency Period	Deficiency Period
8/11/2005	2005-2008	Starting in 2009
8/13/2007	2007-2011	Starting in 2012
9/9/2009	2009-2012	Starting in 2013
1/19/2011	2011-2014	Starting in 2015
1/19/2013	2013-2015	Starting in 2016

March 12, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Third Set of Data Request No. 023
Dated February 26, 2013

Request:

Since 2005, please identify all resource acquisitions of 25 MWs or greater that occurred during the Company's resource sufficiency period.

Response:

PGE interprets this question as resources greater than five years in duration to match the duration of a major resource acquisition. In addition, resources that were approved prior to August 11, 2005 were excluded since the criteria established in Commission Order No. 05-584 were effective on that date.

On January 25, 2006, the PGE Board of Directors approved the acquisition of the Biglow Canyon Wind Farm. The Biglow Canyon project consists of three phases, which came online in the following timeframe:

Phase I - 2007
Phase II - 2009
Phase III - 2010

March 12, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Third Set of Data Request No. 024
Dated February 26, 2013

Request:

Please refer to Macfarlane-Morton/23, and PAC/200, Griswold/29-31. Does PGE agree or disagree with Mr. Griswold's recommendation that a legally enforceable obligation has arisen when the QF approves the final draft power purchase agreement?

Response:

PGE objects to this request on the basis that it calls for a legal opinion.

March 12, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Third Set of Data Request No. 025
Dated February 26, 2013

Request:

Please refer to OAR § 860-029-0010(29), please identify whether PGE recommends that any changes to this rule be made.

Response:

PGE objects to this request on the basis that it calls for a legal opinion.

March 12, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Third Set of Data Request No. 026
Dated February 26, 2013

Request:

Please refer to OAR § 860-029-0010(29), please state whether PGE believes that a legally enforceable obligation can occur before: 1) "a binding, written obligation is entered into between a qualifying facility and a public utility to deliver energy, capacity, or energy and capacity," or 2) "the date agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate."

Response:

Please see PGE's response to REC Data Request No. 024.

March 12, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Third Set of Data Request No. 027
Dated February 26, 2013

Request:

Please refer to Macfarlane-Morton/23 and Issue 6C of the issues list in this proceeding. Please identify what remaining issues should the Commission address in Issue 6C if the Commission adopts PGE's recommendation regarding a year period between a legally enforceable obligation and contract deliveries.

Response:

Consistent with Issue 6C in the UM 1610 Phase I Issues List, PGE intends to propose process steps or procedures to obtain execution of power purchase agreements in Phase II.

November 19, 2012

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OPUC Data Request No. 008
Dated October 31, 2012

Request:

Schedules 201 states that when both parties are in full agreement as to all terms and conditions of the draft Standard Contract, the Company will prepare and forward to the Seller a final executable version of the agreement. How does the Company determine the date when full agreement has been reached?

Response:

The date when full agreement is reached differs depending on interactions with the counterparty. When all necessary information has been provided, as required by Schedule 201 and the contract (for example contact information), and decisions required by Seller have been made and documented in the contract (for instance choosing a pricing option), PGE will prepare and forward to Seller a final executed version of the agreement.

November 19, 2012

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Jay Tinker
Manager, Pricing

**PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OPUC Data Request No. 009
Dated October 31, 2012**

Request:

Please list QFs that signed a non-standard contract since Order 05-584. For each one, please state, on a 20 year levelized basis, how the agreed-upon price compared with the price that would have been paid using the standard contract. Please indicate which, if any, of the non standard contracts were with QFs that were eligible for a standard contract but opted for a non-standard contract.

Response:

No negotiated (non-standard) contracts were executed between PGE and any QFs since Order No. 05-584.

November 19, 2012

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Jay Tinker
Manager, Pricing

**PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OPUC Data Request No. 011
Dated October 31, 2012**

Request:

For each QF listed in question 6, indicate whether the project's interconnection required transmission or substation upgrades. Provide the date that work on the upgrades began and the date the upgrade was complete.

Response:

None of the interconnections for QFs in PGE's system in Data Request No. 006 required transmission or substation upgrades.

<u>REC'S DATA REQUEST NO. 1.3</u>:

In Oregon since 2000, please identify the date of each filing to change its avoided cost rates.

<u>IDAHO POWER COMPANY'S RESPONSE TO REC'S DATA REQUEST NO. 1.3</u>:

Below is a list of filings that resulted in a change to the standard avoided cost rates.

Advice No.	Date Filed	Date Effective
99-02	December 9, 1999	January 19, 2000
01-07	August 28, 2001	October 10, 2001
03-05	October 8, 2003	December 5, 2003
05-06	July 12, 2005	August 11, 2005
06-10	October 20, 2006	May 18, 2007
07-09	October 12, 2007	November 12, 2007
09-12	October 30, 2009	November 30, 2009
10-18	November 9, 2010	December 15, 2010
Order No. 12-146	April 20, 2012	April 25, 2012

Additionally, the following cases were filed seeking a change to avoided cost rates:

Docket	Date Filed
UM 1129	January 20, 2004
UM 1396	October 23, 2008
UE 241	September 14, 2011
UM 1575	January 27, 2012
UE 244	January 27, 2012
Advice 12-02	January 27, 2012
Advice 12-04	February 14, 2012
UM 1590	March 15, 2012
UM 1593	March 26, 2012

This list may not be all inclusive; however, it is what the Company could identify as the most recent filings.

<u>REC'S DATA REQUEST NO. 1.4</u>:

In Oregon since 2005, please identify the date for order acknowledging or not acknowledging each integrated resource plan.

<u>IDAHO POWER COMPANY'S RESPONSE TO REC'S DATA REQUEST NO. 1.4</u>:

Please see the table below listing the Integrated Resource Plan ("IRP") information requested above.

IRP	ORDER	DATE
2004 IRP Acknowledged	Order No. 05-782	June 17, 2005
2006 IRP Acknowledged	Order No. 07-394	September 12, 2007
2009 Addendum to 2006 IRP Withdrawal Application Granted	Order No. 09-249	June 26, 2009
2009 IRP Acknowledged with Requirements	Order No. 10-392	October 11, 2010
2011 IRP Acknowledged with Conditions and Exceptions	Order No. 12-177	May 21, 2012

REC'S DATA REQUEST NO. 1.5:

In the Company's last acknowledged integrated resource plan, please explain whether the capacity and energy of existing QF contracts are considered existing resources. If not, please explain why not. If so, please identify whether the Company assumes that its existing QF contracts will continue for the planning period, and how much energy and capacity is counted for each existing QF contract.

IDAHO POWER COMPANY'S RESPONSE TO REC'S DATA REQUEST NO. 1.5:

Idaho Power's 2011 IRP is the most recent IRP that has been acknowledged by the Public Utility Commission of Oregon. In the 2011 IRP, Idaho Power treats all signed QF contracts as existing/committed resources. Barring any special circumstances, Idaho Power assumes existing QF contracts continue throughout the entire IRP planning horizon.

The forecast energy from each QF project is determined primarily by the most current 5 year rolling average production records, if the project has adequate generation history. For projects that do not have 5 years of history, the project developer's forecast production estimates are used along with available actual project generation data to forecast future energy deliveries.

For capacity, a 5 percent peak-hour capacity factor is used for all wind projects. For all other resource types, the capacity estimate is based on the forecast average energy deliveries.

<u>REC'S DATA REQUEST NO. 2.9</u>:

For non-standard QFs, does Idaho Power agree that is should not make adjustments to avoided cost rates other than those approved by the Oregon PUC?

<u>IDAHO POWER COMPANY'S RESPONSE TO REC'S DATA REQUEST NO. 2.9</u>:

The approved process for a non-standard PURPA QF contract is that a power purchase agreement is negotiated between the QF and Idaho Power pursuant to the Guidelines for Negotiation of Power Purchase Agreements for Qualifying Facilities with Nameplate Capacity of 10 megawatt ("MW") or larger, contained in Schedule 85. Under said guidelines, "The starting point for negotiations is the avoided cost calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Public Utility Commission ..." Consequently the Commission has approved a process whereby adjustments to avoided cost rates can be made through the negotiation of the parties.

REC'S DATA REQUEST NO. 3.3:

Regarding Idaho Power's response to OPUC DR 6, please provide the same information for all non-standard contracts Idaho Power has entered into since the inception of PURPA.

IDAHO POWER COMPANY'S RESPONSE TO REC'S DATA REQUEST NO. 3.3:

Idaho Power has not entered into any non-standard Oregon QF contracts. All Oregon QF contracts have been for standard, or published, avoided cost rates, and not for negotiated rate contracts.

<u>REC'S DATA REQUEST NO. 3.5</u>:

Please review Guideline 8 in Order 07-360, in Docket No. UM 1129. Is Idaho Power proposing that this Guideline be changed?

<u>IDAHO POWER COMPANY'S RESPONSE TO REC'S DATA REQUEST NO. 3.5</u>:

No, Idaho Power is not proposing that Guideline 8 be changed.

Guideline 8 appears in Appendix A to Order 07-360 which is titled, "Adopted Guidelines for Negotiation of Power Purchase Agreements for QFs I0 MW or Larger. Guideline 8 states, "The utility should not make adjustments to standard avoided cost rates other than those approved by the Oregon Commission and consistent with these guidelines."

Guideline 2 from Order 07-360 sets forth the standard avoided cost rates as the starting point for negotiations for Portland General Electric and for PacifiCorp. Guideline 2 sets forth the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW as the starting point for negotiations for Idaho Power.

As stated in Idaho Power's response to REC's Data Request No. 2.9: The approved process for a non-standard PURPA QF contract is that a power purchase agreement is negotiated between the QF and Idaho Power pursuant to the Guidelines for Negotiation of Power Purchase Agreements for Qualifying Facilities with Nameplate Capacity of 10 megawatt or larger, from Order 07-360 and contained in Idaho Power's Schedule 85. Under said guidelines, "The starting point for negotiations is the avoided cost calculated under the modeling methodology approved by the Idaho Public Utilities Commission for QFs over 10 MW, as refined by the Oregon Public Utility Commission ..." Consequently the Commission has approved a process whereby adjustments to avoided cost rates can be made through the negotiation of the parties.

In Mark Stokes' Direct Testimony, p. 3, l. 17, Idaho Power states that it proposes no change to the current authorization stated above from Order No. 07-360 and Schedule 85 to use as the starting point for negotiations the same methodology as that approved by the Idaho Commission.

REC'S DATA REQUEST NO. 3.6:

Please review Guideline 8 in Order 07-360, in Docket No. UM 1129 and Idaho Power's response REC data request 2.9. Is it Idaho Power's position that the "process whereby adjustments to avoided cost rates can be made through the negotiation of the parties" allows Idaho Power to adjust the avoided cost rates for factors other than those listed by the Commission in Order 07-360.

IDAHO POWER COMPANY'S RESPONSE TO REC'S DATA REQUEST NO. 3.6:

Please see Idaho Power's response to REC's Data Request No. 2.9 and 3.5. Any adjustment can be made that is approved by the Commission or consistent with the guidelines set forth by Order 07-360.

<u>REC'S DATA REQUEST NO. 3.8</u>:

Under Idaho Power's proposal regarding legally enforceable obligation, at what point in time in the negotiations will the avoided cost rates no longer be subject to revision or modification?

<u>IDAHO POWER COMPANY'S RESPONSE TO REC'S DATA REQUEST NO. 3.8</u>:

Idaho Power's Schedule 85, Sheet 85-4 through 85-5, sets forth in subsection b. Procedures, i. through vii. the procedure whereby the QF and Idaho Power exchange information and arrive at a draft contract containing avoided cost prices. As stated on Sheet 85-5, subsection b. Procedure, vii. "When both parties are in full agreement as to all terms and conditions of the final draft Energy Sales Agreement, the Company will prepare and forward to the Seller within 15 business days a final executable version of the Energy Sales Agreement. Once the Seller executes the Energy Sales Agreement and returns all copies to the Company, the Company will execute the Energy Sales Agreement."

Idaho Power's proposal regarding legally enforceable obligation is set forth in more detail in the Direct Testimony of Mark Stokes, p. 79-83.

"Idaho Power proposes that the Commission establish that a QF does not bind the Company and its customers to any particular rate or term in a PURPA QF purchase through a legally enforceable obligation until such time as the QF obligates itself legally to that particular rate or term by signing the PUPRA contract itself, regardless of when the utility signs. Further, that there must be some evidence of the utility's refusal to contract, or purposeful delay in the contracting process on the part of the utility, before a QF could avail itself of the remedy of creating a legally enforceable obligation to a particular rate or particular terms and conditions. If the QF believes the utility is refusing to contract, the QF can bring a complaint to the Commission to have the price and terms of a legally enforceable obligation established." Stokes Direct, p. 80, l. 16-25.

Under Idaho Power's proposal a legally enforceable obligation does not arise until the seller (QF) executes the fully agreed to, final executable version of the Energy Sales Agreement referred to above from section vii. of Schedule 85. A legally enforceable obligation may exist at such time, if there is a refusal at that point of the utility to contract, or some other unreasonable delay on the part of the utility. Additionally, should any PURPA regulations or pricing changes occur as established by the Commission, it will require that the final agreement be modified to reflect such changes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation Into Qualifying Facility Contracting and Pricing	)

RESPONSE TESTIMONY OF

DONALD W SCHOENBECK

ON BEHALF OF

THE RENEWABLE ENERGY COALITION

March 18, 2013

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald W. Schoenbeck. I am a member of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I've been involved in the electric and gas utility industries for over 40 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters. I have appeared before the Oregon Public Utility Commission (the "Commission" or "OPUC") on many occasions since 1984. A further description of my educational background and work experience can be found in Exhibit Coalition/201 in this proceeding.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Renewable Energy Coalition ("Coalition").

Q. PLEASE DESCRIBE THE COALITION AND ITS INTEREST IN THIS PROCEEDING.

A. This is explained by Mr. John Lowe in Exhibit Coalition/100.

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. I have been asked to address a list of specific topics most critical to the Coalition. These are: 1) the appropriate method for calculating avoided cost prices for qualifying facilities ("QFs") (Issues 1A1, 1A2, 2A and 4C), including avoided cost pricing for contract renewals (Issue 1C); 2) the manner in which avoided costs should be updated (Issue 3); 3) the eligibility cap for standard offer rates (Issue 5A); and 4) the appropriate contract term and duration for fixed prices (Issue 6I).

Q. PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS ADDRESSED IN THIS TESTIMONY.

A. The current method for calculating avoided costs in Oregon should be retained. For PacifiCorp ("PAC"), and Portland General Electric Company ("PGE"), and Idaho Power Company ("IPC") (collectively, the "Utilities") standard rates should be determined based upon the next avoidable resource of the utility ("Proxy Method"). However, PAC should be allowed to use a single trading hub as the source of its electric market prices as it has proposed for the sufficiency period and IPC should be allowed to use the alternate gas price source it is proposing. The non-standard rates of PAC and PGE should continue to be based upon limited and transparent adjustments to the proxy resource. For IPC, non-standard avoided costs can be determined based upon all the exact pricing method approved by the Idaho Public Utilities Commission ("IPUC") in Order No. 32697 in Case No. GNR-E-11-03 ("IPUC proceeding") which I will refer to as the IPUC integrated resource plan method ("IPUC IRP Method"). IPC should not be allowed to use just selective portions of the IPUC IRP Method in Oregon.

It has been my experience that QF contracts established by Commission order have been for terms far less than the economic life of the QF facility, while utility owned assets are included in rate base for their entire depreciable life. QFs should not be penalized for the shorten term dictated by the Commission. Full avoided cost prices should be paid in each and every year to a QF with a follow on, renewed or extended contract.

It is reasonable to require annual updates to significant inputs used to determine both standard and non-standard prices. However the updates should be limited to items that can be readily verified—such as gas costs—that are in the public domain. The manner in which the annual updates should be done is explained in the testimony of Mr. John Lowe.

The 10 megawatt ("MW") eligibility cap should be retained for standard rates in Oregon. It is a reasonable value given the cost of negotiating a non-standard contract, economies of scale and the Federal Energy Regulatory Commission's ("FERC") Public Utilities Regulatory Policies Act of 1978 ("PURPA").

The Commission should re-affirm a contract term of up to 20 years for standard, non-standard and contract renewals. While I believe fixed prices should be offered for up to this same period of time, in no circumstance should the fixed price period be less than the current Commission approved 15 years, even for an existing QF that is renewing or extending its contract.

<u>AVOIDED COST PRICING METHODOLOGY (ISSUES 1A1, 1A2, 1C, 2A AND 4C)</u>

Q. HOW ARE AVOIDED COSTS CALCULATED FOR STANDARD CONTRACTS IN OREGON?

A. Standard contract rates are based on the next avoidable resource of each utility ("Proxy Method"). During periods when a utility is surplus or has sufficient resources ("sufficiency period"), standard rates are based on forward market prices. At the time the next avoided resource is needed, the standard rates are based on the associated cost of the resource ("deficiency period").

Q. ARE THE UTILITIES PROPOSING ANY CHANGES TO HOW THEY WILL CALCULATE THE STANDARD AVOIDED COST RATES IN THIS PROCEEDING?

A. Yes. PAC is proposing two changes which are: 1) using just a single market trading hub—Mid-Columbia ("Mid-C")—for the market prices during the sufficiency period; and 2) including an integration cost for renewable QFs during the renewable sufficiency period. PGE is proposing to account for integration costs as well. IPC is proposing to incorporate recent changes ordered by the IPUC for calculating its standard rates. These changes are: 1) deriving standard rates for each resource type, including taking into account the expected on-peak capacity deliveries; and 2) the source of the forward natural gas prices.

Q. DO YOU HAVE ANY COMMENTS ON THESE PROPOSED CHANGES?

A. Yes. I fully support PAC's proposal to use the Mid-C trading hub to determine the market price during resource sufficiency periods because, as noted by PAC, this modification would eliminate the need for the use of its production simulation model ("GRID") to determine standard rates. Also, as the Mid-C hub is the most liquid hub in the Pacific Northwest, forward market prices for the sufficiency years can be readily obtained from a third party source to verify the reasonableness of the prices used by PAC.

I will not address the merits of including the cost of integration in deriving standard rates. However, if the Commission does decide to make such an adjustment, PGE's proposal as summarized in the Table 2 makes sense. PGE/100, Macfarlane-Morton/20. If the cost of integration will be included in standard rates, then it is appropriate to charge variable resources and credit non-variable resources as PGE does. As PGE has not provided illustrative calculations of the charges, it is impossible to comment on the precise methodology. However, PGE states that it is flexible on whether the values should be included in the avoided cost schedule or embedded within the contract. On this issue, if such an adjustment is ordered by the Commission, I recommend the values be included within the rate schedule for transparency and easy of understanding all elements of the standard avoided cost rates.

It appears IPC is proposing to emulate the derivation of standard rates as was recently decided in the IPUC proceeding. However, the IPUC has requested additional comments on certain select matters including technology capacity factors used to derive the standard rates for canal drop projects and the other hydro projects. In The Matter of the Commission's Review of PURPA QF Contract Provisions, Case No. GNR-E-11-03, Order No. 32737 (Feb. 5, 2013). The decision calls for comments to be filed on March 25, 2013 with reply comments due on April 8, 2013. Standard avoided cost rates are very sensitive to this critical assumption for all technologies.

Q. HOW DID IPC DERIVE THE CAPACITY FACTORS IT PROPOSED BEFORE THE IPUC FOR DERIVING STANDARD RATES?

A. As noted in IPC's prefiled testimony, the on-peak capacity factors IPC proposed are based on the 90 percent exceedance value. See Idaho Power/200, Stokes/27-28. In other words, 90 percent of the time, the actual delivered capacity for these facilities will be above this amount. This is shown by the following table based upon an IPC exhibit from the IPUC proceeding comparing the 90% exceedance value to the average or expected value.

IPC On-Peak Capacity Factors

QF Type	90% Exceedance	Average
Wind	3.9%	27.4%
Canal Drop	67.1%	78.7%
Solar	33.2%	51.9%
Base Load	92.0%	100.0%

The use of a 90% exceedance value would effectively pay all QFs of the same technology on the performance of some of the worse projects, resulting in payments below avoided costs for superior performing projects. This is inappropriate. To more accurately derive the standard avoided cost rates, the Commission should not even consider using any value below the average or expected value of capacity deliveries that are likely to occur during the peak hours. Also—and what is not stated in IPC's testimony—is the proposed values shown in the above table are based on a limited sampling of QF projects. To illustrate this short coming, consider the IPC QF hydro projects. IPC has over 60 QF hydro projects with roughly one-half being canal drop projects. Many of these canal drop projects have been delivering power since the mid-1980s. Yet, the IPC proposed 67.1% exceedance value and 78.7% average value is based on just 4 projects (and just four years of operation). For the remaining "other" hydro category comprising over 30 QFs, IPC is proposing that avoided cost payments be based on a 33.9% capacity factor. Interestingly, none of the other QF hydro projects were used in the limited sample to derive this value. Instead, IPC used four of its utility owned resources.

At a minimum, the Commission should require IPC to determine the on-peak capacity factor based on the experience of QF projects and not utility-owned projects. Because of these very serious short comings in IPC proposed values, the Commission should reject the capacity factors proposed by IPC. To ensure the best performing QF projects are paid the correct avoided cost of the capacity they deliver, the standard rates for hydro facilities should be based on a 100% on-peak capacity factor and not the 67.1% or 33.9% values proposed by IPC.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING IPC'S PROPOSED CHANGES?

A. Yes. The IPC testimony characterizes its current method for deriving standard avoided cost prices as the "Oregon Method." I recommend the Commission continue to use the Oregon Method for deriving standard avoided cost prices as it is currently implemented for IPC with one exception. The Commission should approve IPC's request to use a different source for the gas price forecast, that being the Energy Information Agency ("EIA") price forecast. This is a reasonable request and will allow for annual updates as I will address later in this testimony.

Q. HOW ARE NON-STANDARD RATES DERIVED BY THE UTILITIES IN OREGON?

A. PAC and PGE non-standard rates are based on the Proxy Method with certain adjustments to take into account the factors enumerated in PURPA in 18 CFR Section 292.304(e)(2). For IPC, the Commission allows IPC to use the IPUC IRP Method based on a far less transparent computer simulation.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED HOW THE FERC FACTORS SHOULD BE TAKEN INTO ACCOUNT?

A. Yes. The Commission addressed the FERC factors in two orders in Docket No. UM 1129. Re Investigation Relating to Electric Utility Purchases from QFs, Docket No. UM 1129, Order No. 05-584 (May 13, 2005); Re Investigation Relating to Electric Utility Purchases from QFs, Docket No. UM 1129, Order No. 07-30 (Aug. 20, 2007). In Order No. 05-584, the Commission explained that the utilities cannot make adjustments for any basis, including the FERC factors, for standard contracts. Order No. 05-584 at 39. The Commission explained that standard contracts are not intended to allow flexibility to negotiate specific adjustments, and that it "is inappropriate to request that standard contracts be subject to potential negotiation to address project-specific characteristics." Id.

In Order No. 07-370, the Commission adopted specific methodologies and approaches to account for specific FERC factors. The Commission also concluded that utilities were not allowed to make adjustments for other FERC factors or any other factor, unless specifically approved by the Commission. Order No. 07-370 at 15-29. The Commission specifically concluded that a "utility should not make adjustments to standard avoided cost rates other than those approved by the Oregon Commission and consistent with these guidelines." Id. at 16 and Appendix A at 3.

Q. DO YOU BELIEVE NON-STANDARD AVOIDED COSTS CAN BE PROPERLY ESTABLISHED USING EITHER A PROXY METHOD WITH DISCRETE ADJUSTMENTS OR AN INTEGRATED RESOURCE PLAN METHOD?

A. Yes. As long as consistent assumptions are used in both methods (such as fuel costs and market price forecasts), all the same costs categories are included in both methods and the expected QF generation pattern is taken into account, I believe employing either method would essentially result in similar avoided cost streams. There are trade-offs between using either one of the two methods. A proxy method is generally easier to explain, implement and understand the resulting prices because the calculus is more straightforward and transparent. The proxy resource calculations can be done using Microsoft's Excel spreadsheet software which most QF owners or developers would already have on their computers. On the other hand, an integrated resource plan method will generally rely on a much more complex "black box" production simulation model that uses thousands of inputs and forecast assumptions in order to derive the avoided cost prices. While most QF owners or developers are likely to understand the workings of an Excel spreadsheet, it is highly unlikely that they are knowledgeable with respect to all the inputs required in a production simulation model such as AURORA—which is used by IPC in its IPUC IRP Method— and the impact the representation of a particular resource could have on the simulation result. Further, the licensing of a third party production model can be very expensive adding to the QF's transaction cost. For example, the AURORA annual licensing fees range from $39,500 to $150,000 for the basic regional modeling capability. While the integrated resource method may not be as transparent as the surrogate resource method, it can do a better job of taking into account a utility's needs by incorporating all the expected loads and resources over the contracting planning horizon. This gives the appearance of a more precisely determined, and therefore more accurate, avoided cost prices but the result is driven by all the numerous forecast assumptions and resource representations, many of which will likely be wrong based on a "20-20" hindsight review. In fact, the most dominating input in any avoided cost calculation tends to be the assumed gas price forecast. As the same gas forecast can be used under either a proxy method or an integrated resource method, the "gain" in going to the hourly simulations is far less significant than having more current market forecasts.

Q. CAN YOU ILLUSTRATE THE IMPACT OF CALCULATING AVOIDED COSTS UNDER THESE TWO METHODS?

A. Yes. In this proceeding, PAC is proposing to replace the Proxy Method with adjustments for determining non-standard prices with an IRP like method it calls the Partial Displacement Differential Revenue Requirement method ("PDDRR Method"). Under the PDDRR Method, PAC performs two production model simulations using its proprietary in house model GRID. To better understand the impact of this proposal, we asked three data requests of PAC to quantify illustrative avoided costs using the same market price assumptions under the existing Proxy Method with adjustments and the PDDRR Method for three QF facility types: wind, hydro and thermal. The following table summarizes the results of these data responses showing the 20 year levelized cost of each technology type under each method.

Comparison between Avoided Cost Methods 20 Year Nominal Levelized Payment - $/MWh								
	PDDRR Avoided Cost Method			Oregon Schedule 38 Method				
Resource	Energy Payment		Annual	Energy Payment		Annual	Difference	
Type	HLH	LLH	Average	HLH	LLH	Average	Amount	Percent
Wind	$49.44	$40.23	$45.59	$51.18	$43.27	$47.87	($2.28)	-4.8%
Hydro	$63.02	$50.91	$57.70	$61.51	$47.39	$55.31	$2.39	4.3%
Thermal	$65.01	$52.21	$59.38	$66.36	$47.53	$58.08	$1.30	2.2%

As shown by the above table, the difference in results is negligible given the substantial amount of additional effort and loss of transparency required under the PDDRR Method.

Q. WHAT IS PAC'S REASONING FOR GOING TO THE PDDRR METHOD?

A. PAC claims the PDDRR Method "is best suited to account for the factors" in Section 292.304(e)(2).

Q. HAS PGE ADDRESSED THE ISSUE OF THE "FERC FACTORS" AS WELL?

A. Yes. PGE wishes to retain discretion to make up on a case by case basis how to account for the FERC factors. When asked to identify the methodology that PGE proposes to use for each of the FERC factors, PGE stated "PGE does not propose any specific methodology be used for the FERC Adjustment Factors. Rather, determination are made on a case-by-case basis and adjustments reflect overall contract risk, a holistic examination of characteristics of the QF, and the terms of the agreement." Coalition/102, Lowe/31-33.

Q. HAS EITHER PAC OR PGE PROVIDED SUFFICIENT EVIDENCE OR JUSTIFICATION TO CHANGE THE CURRENT OPUC POLICY ON IMPLEMENTING THE FERC FACTORS?

A. No. As I have previously stated, I believe that either a Proxy Method with appropriate adjustments or an IRP like method can be used to determine reasonable non-standard avoided costs prices taking into account Section 292.304(e)(2). However, PGE's approach should be rejected because it would provide no guidance to either the QF or the utility, and be contrary to the Commission's policy in Docket No. UM 1129. PGE provides no explanation regarding why the Commission should abandon the specific methodologies or guidance for adjusting the avoided cost rates and contracts for large QFs. If PGE disagreed with the Commission's specific guidance provided in Docket No. UM 1129, then PGE should have submitted testimony explaining why it disagreed with the current approach and recommended specific changes. Instead, PGE has proposed to completely eliminate how avoided cost terms and rates are determined for both standard and non-standard QFs, and replace that with an unknown case-by-case negotiation process. PGE has provided no justification to eliminate the well-developed Commission policies that provide certainty and clear guidance to both QFs and the Utilities.

With regard to PAC, I oppose the adoption of the PDDRR Method as it uses an internally produced black box model that is not available or sold on the market. In addition, the resulting difference in the 20 year prices produced under the two different methods is minimal and well within any reasonable confidence level. For these reasons, plus the increased complexity of the calculus of the PDDRR Method, I recommend the Commission order the continued use of the Proxy Method with transparent adjustments to non-standard contracts for both PAC and PGE.

Q. HOW DO YOU ADDRESS THE CRITICISM THAT THE PROXY METHOD DOES NOT TAKE INTO ACCOUNT CHANGES IN LOAD FORECASTS OR NEW POWER PURCHASE AGREEMENTS?

A. As I will discuss later in this testimony, I believe these factors which could modify the change from a sufficiency period to the deficiency period can be accounted for through annual updates of the avoided cost prices.

Q. HAVE THE UTILITIES ADDRESSED ISSUE 1C ON HOW AVOIDED COST PRICES SHOULD BE DETERMINED FOR A FOLLOW-ON OR RENEWED CONTRACT?

A. PAC and PGE both specifically address this issue and state that contract renewals should not be afforded any different pricing than a new QF. Put another way, these two utilities are proposing that an existing QF would receive only market prices during a utility sufficiency period. It does not appear that IPC has addressed this issue in their testimony.

Q. DO YOU AGREE WITH THE PAC AND PGE PROPOSAL?

A. No. Utility resource additions are recognized as having a certain "lumpiness" that does not allow for a precise matching of resource size to need. As such, it is very likely that a QF wanting to renew its contract would be faced with a period of time at market prices due to a utility sufficiency period in the early years of its follow-on contract. In fact, under PGE's proposed five year term for contract renewals—which I will discuss later in this testimony—a renewing QF would likely receive market prices for a substantial period of the five year term. The capacity provided by the existing QF would continually be displaced or "bumped out" of the resource need stack by any other utility owned resource addition subsequent to the contract execution date. This is patently unfair as the QF facility was not given the opportunity to have a contract equal to its useful life.

Q. HOW CAN THIS BUMPING ISSUE BE ADDRESSED IN PLANNING FOR RESOURCE NEED?

A. As part of the IRP process, the Utilities should seek information from QFs with soon to be expiring contracts (four years for example) and independently evaluate the likelihood of the QF interest in a follow-on agreement. Based upon this evaluation, each utility would include an expected value of QF contract renewals. By using this approach, these resources have not caused any projected short-term surplus and should not be penalized in the form of reduced capacity value in a subsequent follow-on contract. Existing QFs entering into follow-on contract extensions should be provided full avoided cost pricing based on the avoided resource cost each and every year. To not provide full avoided resource cost payments to QFs in follow-on contracts would be inequitable as compared to the treatment afforded utility-owned resources.

Q. ARE YOU AWARE OF HOW OTHER UTILITY COMMISSIONS HAVE ADDRESSED THIS ISSUE?

A. Yes. The recent IPUC decision on avoided cost pricing provides that renewing QFs are not subject to a sufficiency period. The decision states:

> By including a capacity payment only when the utility becomes capacity deficient, the utilities are paying rates that are a more accurate reflection of a true avoided cost for the QF power. However, we find merit in the argument made by the Canal Companies that contract extensions and/or renewals present an exception to the capacity deficit rule that we adopt today. It is logical that, if a QF project is being paid for capacity at the end of the contract term and the parties are seeking renewal/extension of the contract, the renewal/extension would include immediate payment of capacity. An existing QF's capacity would have already been included in the utility's load resource balance and could not be considered surplus power. Therefore, we find it reasonable to allow QFs entering into contract extensions or renewals to be paid capacity for the full term of the extension or renewal.

Order No. 32697 at 21-22.

In the California Public Utilities Commission ("CPUC") rulemaking 04-04-003/04-04-025, the CPUC addressed contract options for existing QFs with expiring contracts in decision 07-09-040 issued on September 20, 2007. The CPUC gave the option to the existing QF to sign an "as-available" contract with a term of up to five years or a firm contract with a term of up to ten years. Both contracts provided for a capacity payment in each and every year.

This Commission should make the same determination regarding capacity or fixed payments for renewing QF. Existing QFs entering into follow-on contracts should be provided avoided costs prices with no sufficiency period.

UPDATING AVOIDED COSTS (ISSUE 3)

Q. WHAT IS THE CURRENT PROCEDURE FOR UPDATING STANDARD AVOIDED COSTS IN OREGON?

A. The Utilities update standard avoided cost rates every two years and within 30 days of each new IRP.

Q. HAVE THE UTILITIES PROPOSED CHANGES TO THIS APPROACH IN THEIR PREFILED TESTIMONY IN THIS PROCEEDING?

A. Yes. PGE is proposing to update the following items once per year: forward energy prices (electricity and gas), fixed operation and maintenance expense levels ("O&M costs"), and the timing (year) of the sufficiency/deficiency period. IPC is proposing to update standard rates consistent with the IPUC method of once per year due in large part to observed movement in natural gas prices. PAC is proposing that forward market prices should be updated quarterly, triggered by the creation of a new "official forward price curve" ("OFPC"). All other inputs linked to the IRP such as O&M costs would continue to be updated at least every two years and within 30 days following an IRP.

Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE TO THE COMMISSION?

A. I generally agree that more frequent updates make sense, but I take exception to three aspects of the utility proposals and one timing issue. The first exception is PAC's proposal to have quarterly updates of market prices. In my view, there needs to be a reasonable balance between recognizing the changes in market prices driven primarily by gas costs and price certainty for project developers. PACs proposal to require quarterly price updates for market prices is simply too frequent given the likely outcome of the update. To explain more fully, market prices changes have much more of a near term impact—the next month or next quarter—as compared to 10 or 15 years out. To illustrate this point, a 5 cent/MMBTU change in the forward gas price of a prompt month would probably result in a price change of roughly 10% (about 0.5 cents/MMBTU) just three years out. This very real dampening in any forward price change or movement is very modest over the entire 10 or 15 contract horizon of the standard offer rates. PAC claims quarterly updates would not be an administrative burden on parties tasked with verifying the rate charges. While this may or may not be the case, I do believe that quarterly filings would result in more frequent arguments between developers and the Utilities over which set of standard rates was in place at the time the contract was executed. Given all these facts, I would limit the updates to just once a year as proposed by IPC and PGE.

My second exception to the updating proposals has to do with the approval or vetting process a particular item has gone through. Proposal to update other more “IRP related” variables such as O&M costs and the timing of the sufficiency/deficiency period should only be allowed after or pursuant to the latest acknowledged IRP plan (or acknowledged update) with its associated public vetting or similar process. Absent the ability to discuss all the specific variables in an open forum and with Commission approval, no changes should be allowed to IRP like values.

My third exception is the scope of what variables or items should be taken into account in performing an update. As I will discuss in a moment, I believe between IRP filings (including any IRP update), the Utilities should be allowed to update for only three—but very significant—items: market prices (both gas and electricity), execution of any new long term contract (greater than four years) and changes in load forecasts.

The timing issue I have with respect to updating avoided cost prices is very simple. The avoided cost update should occur only once a year. In other words, all the items that can be updated should be consolidated into a single filing. Mr. Lowe explains the procedural aspects of this annual update in his direct testimony.

Q. WHAT ARE THE UTILITIES' PROPOSALS FOR UPDATING NON-STANDARD PARAMETERS?

A. It is my understanding that IPC's testimony is seeking to employ the same approach for updating the IRP parameters for deriving non-standard rates that the IPUC recently approved for IPC. This approach includes limited updates for QF contracts, market price changes and load forecast changes using the AURORA production cost simulation model. If my understanding of the IPC proposal is correct—and there is no selective or partial updating—I would support this approach for IPC due to the fact it is the IPUC IRP Method. However, both PGE and PAC are advocating that no restrictions be placed on their ability to update parameters for deriving non-standard charges. I believe this is inappropriate, particularly if the Commission approves PAC's proposed PDDRR method.

Q. WHY DO YOU OBJECT TO THE PAC PROPOSAL TO ALLOW VIRTUALLY CONTINUOUS UPDATING OF THE INPUTS FOR NON-STANDARD CONTRACTS UNDER THE PDDRR METHOD?

A. I have three concerns with allowing unconstrained updating to the GRID inputs, in-between publication of IRPs or updates. First of all, as previously noted, GRID is an "in house" model developed and maintained by PAC. Accordingly, it is a "black box" to all other parties with access controlled by PAC. This is truly an untenable situation for deriving equitable non-standard prices. Second, it creates a substantial burden on the QF to have to analyze and evaluate the reasonableness of any change made by the utility subsequent to the integrated resource planning process. Third, it could allow for game playing by the utility, as there are many modifications that could be made simply to produce lower prices for the QF by parameters that are not even reviewable by the QF developer. All of these concerns could result in complaint proceedings requiring Commission resolution.

Q. WOULD LIMITED AVOIDED COST UPDATES BE ACCEPTABLE BETWEEN TWO-YEAR IRPS IF THE COMMISSION ADOPTS THE PDDRR METHOD?

A. Yes, updates should be allowed for only three factors for deriving avoided cost rates. As noted earlier, a critical input in determining avoided costs are forward market prices. Forward gas prices for up to 10 to 12 years can be tracked and are readily obtainable from third-party providers such as NYMEX or ICE. Allowing for a market price update consistent with an annual standard price update makes sense and is acceptable.

The second type of update to avoided cost prices that should be allowed is for new executed contracts in excess of four years. Contracts in excess of 4 years can be included as they would impact the long-term deficit or surplus position of a utility. Contracts shorter than this term should not be allowed in the update as they would only depress the calculated avoided cost while having no impact on the need for capacity as resources typically take at least this long to be built.

The third and final update would be to allow for an updated load forecast as long as it had been discussed and reviewed by the Commission Staff and other interested parties through some public process. Allowing these three very significant—but also very limited updates—would be acceptable and go a long way to addressing any concerns regarding major cost driver categories. Other updates such as changes in forced outage rates for generating plants, affiliated coal costs or operation and maintenance expenses should not allowed unless it is part of an IRP update.

ELIGIBILITY CAP (ISSUE 5A)

Q. PLEASE EXPLAIN THE IMPORTANCE OF THE ELIGIBILITY CAP WITH REGARD TO AVOIDED COST PRICING IN OREGON.

A. The MW cap determines if a QF is eligible for a standard contract with published prices, terms and conditions as compared to having to negotiate a contract with the utility.

Q. WHAT HAS THE ELIGIBILITY CAP BEEN IN OREGON?

A. Until Order No. 05-584, the cap had been 1 MW for a standard offer contract. With the issuance of this order, the Commission increased the eligibility cap to 10 MWs.

Q. WHAT ARE THE UTILITIES PROPOSING IN THIS PROCEEDING FOR AN ELIGIBILITY CAP VALUE?

A. PAC is proposing to lower the cap to just 3 MW. IPC is proposing that the cap be set by type of technology. For wind and solar QFs, IPC is proposing a cap of just 100 kilowatt ("kW"). For all other QFs, IPC is proposing to retain the existing cap of 10 MW. PGE is taking the most extreme position advocating a cap of only 100 kW for all QFs.

Q. WHY IS PGE PROPOSING SUCH A RADICAL CHANGE TO THE ELIGIBILITY CAP SIZE?

A. PGE provides four reasons for its proposal which are: 1) the cost of negotiating a QF contract are immaterial as compared to its capital cost; 2) the standard contract prices impose unreasonable costs on PGE customers; 3) the 10 MW cap is 100 times higher than the cap "recommended" under PURPA; 4) and the 10 MW cap is significantly higher than other states in the region. PGE/100, Macfarlane-Morton/4, lines 7-14.

Q. DO YOU AGREE WITH PGE'S PROPOSAL WITH REGARD TO ELIGIBILITY SIZE?

A. No. The proposed eligibility size is far too small. At a cap level of just 100 kW, virtually every QF contract would be a non-standard contract requiring the QF to negotiate the prices, terms and conditions of the agreement. Contrary to PGE's assertion, other state commissions have ordered caps much greater than 100 kW. Only recently did the IPUC impose a cap of 100 kW, but this was exclusively for wind and solar QF facilities. For all other technologies, the IPUC has a cap of 10 AMW (in any one month) which is most instances would be greater than the existing 10 MW cap in Oregon. In November 2010, as part of the settlement on avoided cost matters, the California Public Utilities Commission approved an eligibility cap of 20 MW for standard offer contracts.

Q. WHY HAVE THESE COMMISSIONS APPROVED ELIGIBILITY CAPS IN THE 10 TO 20 MW RANGE?

A. I believe there are several significant reasons which have to do with transaction costs, economies of scale, lack of alternative markets and FERC's regulations for implementing PURPA in response to the Energy Policy Act of 2005 ("EP Act 2005").

Forcing virtually every QF to negotiate a non-standard contract adds to the upfront transactional costs by extending the period over which the QF could ascertain if the project was commercially viable based upon a complete review of the prices, terms and conditions offered by the utility. In addition, it would only be prudent for the QF to retain the necessary expertise to assist in the evaluation and negotiation of the contract. It has been my experience that negotiating a non-standard QF contract with a utility can take a great deal of time. In some instances, the slowness in which a utility will negotiate a contract can cause a project to not be built as the developer may not have the time or money for an extended negotiation process. These additional transactional costs could well make a smaller project uneconomical. While PGE makes the bald assertion that transaction costs would be immaterial as compared to the capital cost, it has provided no evidence of what these costs are.

Setting a low cap may also impact project viability due the economies of scale that are inherent in the utility industry. Typically, utility-owned resources benefit from being sized large enough such that the dollar-per-kilowatt investment required to build the plant is less than for a much smaller sized QF of the same basic technology. Establishing a reasonable size cap, in the 10 to 20 MW range will allow some scaling benefits for the QF.

The typical short-term power sale trades in the Pacific Northwest electricity market are for blocks of 25 MW for each and every hour of the “on-peak” period, Monday through Saturday, 6:00 a.m. to 10 p.m., or “off-peak period”, all other hours plus holidays. Only in California is there an organized market run by an independent administrator, California Independent System Operator, for day-ahead or real-time products in the Western United States. Consequently, QFs in the Pacific Northwest cannot provide the product most traded nor do they have access to competitive organized markets for their products.

Finally, the EP Act 2005 established a new section within PURPA that relieves a utility of the obligation to purchase QF power if the utility has sought and received a waiver of the obligation from FERC by showing the QF has wholesale market access under certain standards. However, in implementing EP Act 2005, FERC ruled that even where QFs have market access, the utility is only relieved of the must purchase obligation for QFs larger than 20 MW. In other words, utilities must still purchase QF power from “smaller” facilities if the facility is less than 20 MW. All these factors suggest an eligibility cap much greater than PGE’s 100 kW value.

Q. WHAT IS YOUR RESPONSE TO PGE'S ASSERTION THAT CONTINUATION OF A 10 MW CAP IMPOSES UNREASONABLE COSTS ON RATEPAYERS?

A. It must first be pointed out that the workpaper supporting PGE's claimed harm to ratepayers of $6.8 million is solely based on the "harm" associated with a wind project. PGE has provided no comparable analysis for other types of QF technologies including combined heat and power or hydro facilities. As such, PGE can only claim this harm would only be for the specific type of project it modeled. PGE has provided no evidence of rate payer harm associated with these other QF technologies. Consequently, the Commission should not lower the eligibility cap for the other QFs.

Q. ARE YOUR CRITICISMS OF PGE'S PROPOSAL APPLICABLE TO PAC'S 3 MW PROPOSAL AS WELL?

A. Yes. The majority of PACs testimony on the eligibility size issue is addressing QF wind projects and not other QF technologies. The only additional argument PAC presents is the "disaggregation of large single projects in multiple small projects." <u>See</u> PAC/200, Griswold/20, line 14. However, even this argument is directed to wind (and perhaps solar) projects but not other technologies. The Commission should re-affirm an eligibility cap of 10 MW.

<u>CONTRACT TERM INCLUDING FIXED PRICE PERIOD (ISSUE 6I)</u>

Q. WHAT IS THE COMMISSION-APPROVED MAXIMUM CONTRACT TERM FOR QFS IN OREGON?

A. The Commission approved a maximum contract term of up to 20 years that includes fixed prices for the first 15 years of the contract.

Q. ARE THE UTILITIES PROPOSING ANY CHANGES TO THESE TERMS IN THIS PROCEEDING?

A. Yes. While the Utilities are in agreement that the maximum term should continue to be 20 years, PAC and IPC are proposing that the fixed price term be shortened to just 10 years. PGE is the only utility advocating that the fixed price period should stay at 15 years. In addition, PGE is advocating that these terms should only apply to a new QF. For an "existing QF" PGE is proposing the maximum contract term should not exceed five years.

Q. WHAT WAS THE COMMISSION REASONING FOR SELECTING A 15 YEAR FIXED PRICE PERIOD?

A. As explained and set forth in Order No. 05-584, the Commission focused on the trade-off between a QFs ability to obtain financing for the project and the likelihood of accurately projecting avoided costs over extended periods of time.

Q. HAS PAC OR IPC PROVIDED ANY EVIDENCE IN THIS PROCEEDING TO SUPPORT A SHORTER FIXED PRICE PERIOD?

A. No. PAC's only evidence is the assertion that 43%—a "large percentage" —of new QFs "elected terms of 15 years or less." See PAC/200, Griswold/33, lines 2-7. A cursory review of the confidential workpaper this assertion is based on is quite revealing. First, while it is correct that 43% (actual value appears to be 42%) of the QFs elected terms "***15 years*** or less" a more accurate metric to support shortening the fixed price period to ten years would be to provide the percentage of QFs that elected terms that were ***less than 15 years***. The answer is just 18%. The remaining 24% comprising PAC's 42% value elected a 15 year term. Put another way, the vast majority of QFs that executed contracts subsequent to Order No. 05-584—82%—elected contract terms of at least 15 years. This suggests that a 15 year fixed price term is a critical factor for QF development and should be expected as financing entities typically want the term of the contract to be longer than the term of the associated debt. IPC offered no evidence but argued that a long fixed price term shifts market price risk from the QF to IPC's customers.

Q. WHAT IS YOUR RESPONSE TO IPC'S ASSERTION THAT LOCKING IN A LONGER FIXED PRICE TERM SHIFTS RISK TO RATE PAYERS?

A. The implication of IPC's testimony is that customers will be harmed from locking in fixed prices for a long period of time. This, of course, may not necessarily be the case. In this current period of low gas prices, locking into longer term contracts may in fact provide a substantial benefit if gas prices were to rise above current projections. In actuality, locking into fixed price arrangements reduces IPC's exposure to market price movements. More importantly, however, the Idaho Power witnesses really appear to be arguing that a different standard of prudency and reasonableness should be used for judging QF contracts as compared to utility owned resources. For QF facilities, IPC seems to imply there should be an ongoing review as to the appropriateness of the QF payments.

However, for utility-owned resources or inter-utility contracts, IPC, like all other utilities, will argue just one reasonableness review should be conducted based on the standard of what was known at the time the decision to acquire the resource or execute the contract was made. This approach is consistent with the PURPA standards. FERC's regulations provide QFs the right to receive energy and capacity payments based on a forecast of "the avoided costs calculated at the time the obligation is incurred." 18 CFR Section 292.304(d)(2)(ii). This should be the exact same standard for judging the reasonableness of QF contracts employed by this Commission. Finally, I find it disingenuous that IPC would argue on the one hand that this Commission should implement the IPUC avoided cost methods while at the same time seeking to shorten the fixed price before this Commission. In the recently concluded IPUC proceeding, IPC advocated a maximum standard offer contract term of just five years. The IPUC concluded the existing 20 year term is still appropriate and the IPUC standard contract method includes having fixed prices for the full 20 years.

Q. DO YOU AGREE WITH PGE'S PROPOSAL TO ONLY OFFER A CONTRACT TERM NO GREATER THAN FIVE YEARS TO EXISTING QFS?

A. No. PGE's has provided no support for the proposal, it is inequitable and it is discriminatory.

Q. WHY?

A. First, PGE's testimony addressing the five-year term is literally only two sentences:

> However, terms for existing QFs should not exceed 5 years. Those QFs generally have already recovered their investment and should no longer be financing a project.

PGE/100, Macfarlane-Morton/24, lines 3-4. The lack of specificity and the use of word "generally" calls into question the veracity of the two sentences. Moreover, with only a five year term and the current sufficiency/deficiency pricing method, undoubtedly, several years of the five year period would be at market prices reflecting only short-term energy costs. As such, the capacity provided by any QF under a five-year extension agreement or a follow-on contract could well be bumped or displaced by any utility-owned or contracted-for resource that has been executed subsequent to the initial QF contract. For resources such as those owned by the QF companies that have been providing reliable capacity for a number of years, the PGE's proposal is patently inequitable. The testimony is silent on the cost associated with maintaining the existing facilities and whether or not revenue based on market prices is sufficient to allow for the continued operation of these facilities. Until such time that PGE can demonstrate this to be the case, the 5 year term limit should be rejected.

Q. WHY IS THE PROPOSAL DISCRIMINATORY?

A. It discriminates between how utility resources are treated versus the QF facility. The QF facility is limited to a 20 year contract under the Commission approved directives while a utility owned facility is included in rates for its entire economic life. As deliveries from QFs are in part in lieu of building company-owned resources and they have comparable economic lives, a follow-on contract should be provided for an extended period and not be limited to just five years as is being proposed by PGE.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE MAXIMUM CONTRACT TERM AND THE FIXED PRICE PORTION IN THIS PROCEEDING?

A. The Commission should continue to allow QFs the ability to execute a contract for up to 20 years. This should apply to both new facilities and existing facilities seeking a follow-on contract. This is equitable and necessary as QF facilities have useful lives well beyond an initial 20 year contract term. This is simply providing the QF the very opportunity experienced by a utility owned facility. I believe fixed prices should be offered—or electable—for the entire term of the contract. In my view this is again fair and supported by PURPA in that the contract prices reflect avoided cost at the time a contract is signed. Any “20-20” hindsight review after the fact has never been applied to a utility owned resource and it should not be applied to a QF facility. However, I recognize the Commission rejected this argument in Order No. 05-584. As a “second best” recommendation, I urge the Commission to retain the current 15 year fixed price period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
	)
Investigation Into Qualifying Facility Contracting and Pricing	)

EXHIBIT COALITION/201

QUALIFICATIONS OF DONALD W. SCHOENBECK

March 18, 2013

QUALIFICATIONS AND BACKGROUND OF DONALD W. SCHOENBECK

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Donald W. Schoenbeck, 900 Washington Street, Suite 780, Vancouver, Washington 98660.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and I am a member of Regulatory & Cogeneration Services, Inc. ("RCS").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Kansas and a Master of Science Degree in Engineering Management from the University of Missouri.

From June of 1972 until June of 1980, I was employed by Union Electric Company in the Transmission and Distribution, Rates, and Corporate Planning functions. In the Transmission and Distribution function, I had various areas of responsibility, including load management, budget proposals and special studies. While in the Rates function, I worked on rate design studies, filings and exhibits for several regulatory jurisdictions. In Corporate Planning, I was responsible for the development and maintenance of computer models used to simulate the Company's financial and economic operations.

In June of 1980, I joined the consulting firm of Drazen-Brubaker & Associates, Inc. Since that time, I have participated in the analysis of various utilities for power cost forecasts, avoided cost pricing, contract negotiations for gas and electric services, siting and licensing proceedings, and rate case purposes including revenue requirement determination, class cost-of-service and rate design.

In April 1988, I formed RCS. RCS provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers. We also assist in the negotiation of contracts for utility services for large users. In general, we are engaged in regulatory consulting, rate work, feasibility, economic and cost-of-service studies, design of rates for utility service and contract negotiations.

Q. IN WHICH JURISDICTIONS HAVE YOU TESTIFIED AS AN EXPERT WITNESS REGARDING UTILITY COST AND RATE MATTERS?

A. I have testified as an expert witness in rate proceedings before commissions in the states of Alaska, Arizona, California, Delaware, Idaho, Illinois, Maryland, Montana, Nevada, North Carolina, Ohio, Oregon, Washington, Wisconsin and Wyoming. In addition, I have presented testimony before the Bonneville Power Administration, the National Energy Board of Canada, the Federal Energy Regulatory Commission, publicly-owned utility boards and in court proceedings in the states of Washington, Oregon and California.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
	)
Investigation Into Qualifying Facility Contracting and Pricing	)

RESPONSE TESTIMONY OF

JEREMIAH CAMARATA AND EDSON PUGH

ON BEHALF OF

THE RENEWABLE ENERGY COALITION

March 18, 2013

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeremiah Camarata. I am the District Manager at Farmers Irrigation District ("FID"), which is a member of the Renewable Energy Coalition (the "Coalition"). My business address is Farmers Irrigation District, 1985 Country Club Road, Hood River, OR 97031.

My name is Edson Pugh. I am the General Manager at Deschutes Valley Water District ("DVWD"), which is a member of the Coalition. My business address is Deschutes Valley Water District, 881 S.W. Culver Highway, Madras, OR 97741.

Q. MR. CAMARATA, PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I have directly worked for private, non-profit, and public water resource-based entities since 2003. Before that, I grew up on farmland, earned degrees from prominent universities, and travelled some of the world. In the last decade, I have served to enrich over 4 million acres of agricultural land and have worked diligently towards water and power operational efficiencies and water conservation measures that create jobs, benefit the environment, and serve the common good. I have a Masters degree in Landscape Architecture, serve as the Vice Chair of the Oregon Water Resource Congress Federal Affairs Committee, and am currently responsible for delivering water to 5,900 acres of high value agricultural land. My district's mission is to support this important economy by promoting ecologically, socially, and financially sustainable agriculture by providing energy and irrigation service for the common good. A further description of my educational background and work experience can be found in Exhibit Coalition/301 in this proceeding.

Q. MR. PUGH, PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I have worked for Deschutes Valley Water District for 27 years as the district's engineer, the last 8 years as the general manager and engineer. I have been a registered professional engineer since 1990. Our district's mission is to provide safe and good tasting drinking water at a reasonable cost to existing and future DVWD patrons while continuing a high level of customer service.

A further description of my educational background and work experience can be found in Exhibit Coalition/302 in this proceeding.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. We are testifying on behalf of the Coalition in this Oregon Public Utility Commission (the "Commission" or "OPUC") proceeding.

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. Our testimony will provide background information about FID and DVWD (jointly, the "Districts"), our hydroelectric projects which sell power to PacifiCorp as qualifying facilities ("QF"), as well as address Issues 5A (Should the Commission change the 10 MW size threshold for standard contracts) and 6I (the appropriate contract term; the appropriate duration for the fixed price portion of the contract). Issue 6I also requires us to address whether existing projects should receive value for capacity during future resource sufficiency periods when entering into a replacement power purchase agreement and how such treatment affects the need for applying levelization of avoided cost prices.

FARMERS IRRIGATION DISTRICT PROJECT AND CONTRACT SPECIFICS

Q. MR. CAMARATA, PLEASE DESCRIBE FID.

A. FID, a nonprofit government agency founded in 1874, is located in Hood River, Oregon, in the beautiful, culturally rich Columbia River Gorge. Water is provided to 5,900 acres of land and 1,851 customers, both residential and agricultural. Hood River County is known for its beautiful orchards and depends heavily on their production of pears, apples, and cherries for economic vitality. The county produces more winter pears than any county in the United States and the economic footprint of agriculture in Hood River County was estimated at $306 million in 2009. FID's mission is to support this economy by promoting ecologically, socially, and financially sustainable agriculture by providing energy and irrigation service for the common good.

FID has nine primary water diversions, all of which are run-of-the river (no dams on free flowing rivers and creeks) and protected by state of the art head works and our patented fish friendly Farmers Screens approved by National Oceanic and Atmospheric Administration ("NOAA") fisheries. Having received state and federal agency approval for The Farmers Screen, we patented the technology and now license it to the Farmers Conservation Alliance with the condition that profits be used for the united benefit of fish, farms, families, and environment. The screen investments have dramatically stabilized and increased our hydro production while saving farmers hundreds of thousands of dollars per year. These technologies and concepts extend to many other water districts in the state and beyond. We are proud of our century-long efforts in innovative efficiencies and environmental protection and plan on continuing to be the leaders in irrigation management by aggressively raising the bar in sustainable agriculture, power production, fish screening standards, and water conservation measures into the foreseeable future. Since implementation of hydropower production capabilities in the mid-eighties, our district has made over $37 million in capital improvement projects that create and maintain jobs, and support the community and environment. None of this would be possible without dependable, fair, long-term power-sales agreements. Continuation of power-sales agreements that are dependable, fair, and long-term in nature are absolutely critical to our operational budgets, commitments to agriculture, long-term debt service owed to private, state and federal entities, necessary investments in critical water conveyance infrastructure, and the entire fabric of community and commerce that have come to depend on us as a public entity.

Q. MR. CAMARATA, PLEASE DESCRIBE YOUR QF PROJECT.

A. FID owns, operates, and maintains a hydroelectric facility for the generation of electric power, including interconnection facilities, located in Hood River Oregon (within the region covered by the Western Electricity Coordinating Council) with a Facility Capacity Rating of 4,800 kilowatts ("kW"). FID sells its net output directly to PacifiCorp and the associated, unbundled renewable energy credits ("RECs") to various other public and private entities under RPS mandate or voluntarily concerned about carbon footprint and climate change. Generating electricity from local water systems has been a critical component of FID daily operations since the mid-eighties. FID has two Francis style turbine generators, a 1000 kW and a 2000 kW unit, and one 1800 kW Pelton style turbine. FID power plants are modern and utilize sophisticated equipment and technology. FID generators produce an approximate average of 23 thousand megawatt ("MW") hours per year. With our many capital improvement projects, infrastructure rehabilitation efforts, innovation, and water conservation measures implemented over time, our production is stable.

Q. MR. CAMARATA, PLEASE DESCRIBE YOUR CURRENT QF CONTRACT WITH PACIFICORP.

A. FID's current contract term became effective on January 1, 2011, and shall terminate on December 31, 2025. Contract prices are paid for on-peak and off-peak production. This contract replaces the original contract of 25 years which expired on December 31, 2010. The original contract contained both energy and specific capacity payments. The current contract applies limited levelization of prices to help FID in minimizing severe cash flows mainly caused by resource sufficiency year avoided cost pricing under Schedule 37 and the non-payment for capacity during such sufficiency years. Had FID continued to receive capacity payments for the sufficiency years 2011 through 2013, the levelization of prices under our 2010 power purchase agreement would have been unnecessary.

FID also has a separate interconnection agreement that was executed November 24, 2010.

DESCHUTES VALLEY WATER DISTRICT PROJECT AND CONTRACT SPECIFICS

Q. MR. PUGH, PLEASE DESCRIBE DVWD.

A. DVWD is a government agency and special district as defined by ORS § 264. DVWD is a public water supplier to approximately 5,000 service connections to residential, commercial, and industrial customers in the communities of Culver, Metolius, Madras, and their surrounding areas in Jefferson County, Oregon.

DVWD's hydro-electric plant is integral to the District's mission in keeping water rates reasonable and funding capital improvement projects for the water system infrastructure. DVWD's service area is over 23 miles long and is served by over 400 miles of pipelines.

Q. MR. PUGH, PLEASE DESCRIBE YOUR QF PROJECT.

A. DVWD owns, operates, and maintains the Opal Springs hydroelectric facility for the generation of electric power, including interconnection facilities, located in Jefferson County, Oregon (within the region covered by the Western Electricity Coordinating Council) with a Facility Capacity Rating of 4,300 kW. DVWD sells its net output directly to PacifiCorp and the associated, unbundled RECs to various other public and private entities under Renewable Portfolio Standards ("RPS") mandate who are voluntarily concerned about carbon footprint and climate change. Opal Springs Hydro is a "run of the river" low head hydro-electric facility with a single generator driven by a Kaplan turbine. Power production is consistent on a monthly basis with extra production during spring run-off. The plant usually produces over 360 days per year.

Q. MR. PUGH, PLEASE DESCRIBE YOUR CURRENT QF CONTRACT WITH PACIFICORP.

DVWD's current thirty-five year term contract was executed in 1982 with power deliveries to begin January 1, 1985 and it shall terminate December 31, 2020. This original contract contains both energy and specific capacity payments based upon demonstrated capacity, and further is the original type of non-bifurcated power purchase and interconnection agreement. We will likely need to negotiate a new interconnection agreement before our current contract expires.

THE 10 MW SIZE THRESHOLD SHOULD NOT BE REDUCED

Q. DO YOU SUPPORT KEEPING THE COMMISSION'S CURRENT 10 MW SIZE THRESHOLD?

A. Yes.

Q. WHY IS IT IMPORTANT FOR PROJECTS OF YOUR SIZE TO BE ABLE TO SELL POWER TO PACIFICORP UNDER A STANDARD CONTRACT?

A. The primary reason is to avoid being subject to negotiation of replacement power purchase agreements that are not based upon known published prices and being required to negotiate the prices and contract terms. The Districts do not have the expertise to negotiate such prices and terms without significant third-party assistance and expense. Further, it is expected that such agreements could not be reasonably met without significant time delays, controversy, and risks associated with fluctuating prices and terms.

Q. THE UTILITIES HAVE ARGUED THAT THE SIZE THRESHOLD IS NOT IMPORTANT BECAUSE MANY QFS ARE LARGE, SOPHISTICATED ENERGY DEVELOPERS. DOES THIS APPLY TO YOUR FACILITIES?

A. No, although the Districts may be relatively large in terms of end-users of water and other delivered resources, our primary business is not the development of energy producing projects. Our focus is the continued operation of the water systems needed to serve our communities and maintaining the safe and reliable nature of our current hydroelectric projects. We have little, if any, interest in or opportunity for new project development.

Q. HOW IMPORTANT IS IT TO AVOID DELAYS AND HAVE AN EXPEDITIOUS COMPLETION PROCESS FOR YOUR POWER PURCHASE AGREEMENT?

A. Very important for several reasons discussed below.

Q. PLEASE EXPLAIN FURTHER.

A. Under the current Schedule 37 process in PacifiCorp's case, little negotiation should be necessary to complete the power purchase agreement since it is essentially a "fill-in- the blanks" form agreement. Then current published prices are added to the agreement as an exhibit. Provided avoided cost prices are not in the process of changing and there are not other obstacles, the agreement should be able to be executed within a few months. We have been informed that the negotiation process even for standard contracts can take much longer, but this is an issue that will be addressed in Phase II and we do not address it here. In any event, the successful completion of the agreement is more assured in the standard contract process than if all terms and prices must be negotiated. This is not the case with negotiated contracts which include negotiated prices whose basis or beginning point is subject to constant change. We are not large, sophisticated energy developers, nor can we afford to waste or justify tax payer dollars on non-expeditious process in which we have very little expertise.

THE COMMISSION SHOULD MAINTAIN THE CURRENT CONTRACT DURATION AND CAPACITY PAYMENTS

Q. WHAT ARE THE COMMISSION'S CURRENT RULES AND REQUIREMENTS REGARDING CONTRACT TERM AND CAPACITY PAYMENTS?

A. In 2005, the Commission determined that QFs should have the option to select contracts of up to 20 years, with fixed prices for the first 15 years. Re Investigation Relating to Electric Utility Purchases from QFs, Docket No. UM 1129, Order No. 05-584 at 19-20 (May 13, 2005). Capacity value is paid through the on-peak prices during the resource deficiency period which are included in PacifiCorp's Schedule 37 approved by the Commission.

Q. DO YOU SUPPORT THE COMMISSION'S CURRENT POLICY?

A. The fixed price period of 15 years is adequate, and necessary to facilitate the long-term planning of the hydro operations in context with other planning associated with the water system. This includes financing needed to make system improvements, repairs, and meet or exceed environmental requirements. The payment of capacity can be through a separate capacity payment as in the original FID-PacifiCorp contract or through the current application via on-peak energy prices.

The Commission should consider adopting new policy specific to existing projects providing for the continuum of payment for capacity when entering into a new contract. Coalition witness Don Schoenbeck addresses this issue in his testimony.

Q. HAS PGE PROPOSED TO CHANGE THIS POLICY FOR EXISTING QFS.

A. Yes. PGE has proposed that existing QFs should not be allowed to enter into contracts longer than five years. PGE/100, Macfarlane-Morton/23-24. PGE also has proposed to keep the current resource sufficiency/deficiency demarcation, which means that existing QFs will be required to enter into short term five year contracts in which the first two or more years of resource sufficiency based prices will always be at lower market rate without capacity payments. Even if a QF is willing to obligate itself for a longer period of time and provide needed capacity to the utility, under PGE's proposal, the QF only receives fixed prices or capacity payments for about half of its contract. This is the result of each 5-year agreement having at least two or more years of resource sufficiency based prices. Under existing policy, an existing QF can enter into a 15 year contract and obtain fixed payments, including capacity, except during the initial resource sufficiency years. In addition, without the adoption of a new Commission policy regarding the continuum of capacity payments for new replacement contract for existing projects, PGE's proposal capacity payments would be applied similar to a faucet being turned off and on, and essentially leaving us high and dry.

Q. PGE SUPPORTS ITS POSITION ON THE GROUNDS THAT NEW QFS NEED LONGER CONTRACTS TO OBTAIN FINANCING, BUT EXISTING QFS DO NOT NEED LONGER CONTRACTS. PLEASE RESPOND.

A. Our existing projects are part of a large complex of integrated facilities that primarily deliver water to citizens and businesses. In order to financially plan, engineer, build and operate these systems, including the hydro projects, it is necessary to incorporate long-term financing. Even with a 15-year power contract term it is absolutely necessary to have long-term financing in place which exceeds such term. Short-term contracts of five years would make long-term planning excessively challenging, and very risky for District finances. Short-term contracts would also handicap our ability to provide and maintain safe infrastructure and reliable water supply to citizens, including but not limited to large and small agri-business.

Q. DO EXISTING QFS NEED TO MAKE CAPITAL IMPROVEMENTS?

A. Absolutely, and in most cases capital improvement projects are going on continuously. Responsible districts and water suppliers typically have a substantial annual ongoing capital improvement and safety program that relies on long-term debt. District water systems are expensive to maintain and large piping and other capital improvement projects are critical to supporting the needs of a growing society dependent on water and agriculture. Capital improvements rely on long-term debt financing and our ability to meet debt service. Long-term financing necessary to maintain safe and aging infrastructure is not only critical to saving and protecting lives, but simply the responsible thing to do.

Q. DO EXISTING QFS NEED PRICING STABILITY?

A. Price stability and certainty for current and potential new power purchase agreements is of utmost importance. Pricing stability and certainty are essential for reliable water service. For districts with existing contracts, reliability on power purchase agreement ("PPA") pricing is commensurate with water being available out of the faucet at your home, or not.

Q. WHY IS IT IMPORTANT FOR A QF TO NOT RENEGOTIATE A CONTRACT EVERY FIVE YEARS?

A. In addition to the reasons above, frequent renegotiations would harm our ability to make long-term plans that rely upon stable prices. Entering into a standard power purchase agreement every five-years would be extremely challenging, and subject Districts to unnecessary costs, risks, harm, and even the re-opening of interconnection agreements. Changing the standard price and contract threshold to a lower level, thereby requiring the Districts to negotiate pricing and contracts every five years would be unmanageable at best. The Districts should not be subjected to perpetual and wasteful negotiation that would ultimately harm their end-users who depend upon reliable water service.

Q. DOES A FIVE YEAR TERM HARM A QF'S ABILITY TO SELL ITS RENEWABLE ENERGY CREDITS?

A. Yes. In addition to generating power, the electrical generation output of our projects also produce non-energy environmental, economic and social benefits. Some of these separate non-energy benefits are called "green tags," "tradable renewable certificates," and "RECs," which can be sold on the market to third parties or the utilities themselves. Purchasers of these non-energy attributes often wish to enter into long term contracts in excess of ten years. Based on our personal experience, we believe that we can procure greater sales opportunities and obtain much higher and more stable prices if we can enter into contracts for periods greater than five years. However, we may not be able to agree to sell the non-energy benefits under a long term contract if we can only enter into a five-year contract to sell our electricity to the utility. Therefore, a short five-year contract can cause significant and unnecessary harm to a QF's ability to sell the non-energy attributes. We are more than willing to develop our own innovative ways to realize a premium on our power production, but allowing sufficient and fair rates over a reasonably long time period to support and plan our projects with base production revenue is absolutely paramount.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
	)
Investigation Into Qualifying Facility Contracting and Pricing	)
	)

EXHIBIT COALITION/301

QUALIFICATIONS OF JEREMIAH CAMARATA

March 18, 2013

Overview

Currently the General Manager of Farmers Irrigation District, I have experience within a diversity of fields including environmental planning, landscape architecture, site engineering, GIS/GPS, ag and urban irrigation, renewable energy credits and energy trusts, and hydropower generation. I have been fortunate enough to play roles on award winning teams, have worked on a variety of implementation, development, and analytical projects for various government agencies, businesses, and non-profit water/natural resource organizations. I have designed, implemented, and managed annual operational budgets up to $5m, and individual projects of equal value. Having degrees in Landscape Architecture and Environmental Planning, I enjoy working on and towards balanced, systemic-based solutions. I currently serve on multiple state and community level planning committees and very much enjoy being involved in my community.

Professionally, I have worked in the fields of GIS-based IT, marketing, sales, outreach, landscape architecture, agricultural irrigation, and hydropower generation. I am planning-oriented and tend to focus on development & outreach strategies, statistics & forecasting, budgets, federal/state alignment, research, logistics, customer relations, grant writing, and technical oversight of product and project implementation. I enjoy brainstorming and fostering creative concepts and shepherding such ideas towards eventual project funding and implementation.

Over my career, I have served to enrich over 4 million acres of agricultural land and have worked diligently towards operational efficiencies and water conservation measures that also create jobs and foster positive working environments.

Relevant Work Experience

2011-Present: General Manager, Farmers Irrigation District, Hood River, OR
2010-2011: Special Projects and Programs Manager, Assistant Manager, Farmers Irrigation District, Hood River, OR

2009-2011: Business Development, Outreach, Project Management, Farmers Conservation Alliance (FCA), Hood River, OR

2002 -2009: Creative Development, Business Development Manager, Geo-Spatial Solutions Inc. (GSS), Bend, OR

2003: Graduate Research Fellow; Conservation and Restoration Analysis, Internet Mapping Systems, Institute for a Sustainable Environment Research Lab, University of Oregon, Eugene, OR

2002: Graduate Teaching Fellow (Advanced GIS), University of Oregon, Eugene, OR

2000 - 2001: Travelling GIS Application Development/Internet Mapping Systems Consulting/Statistics Interpretation & Presentation/Technical Marketing Internship for ESRI-Sweden and LandFocus AB; Gävle, Sweden, - Informi GIS A/S; Lyngby/Copenhagen, Denmark, - ESRI-Germany Geoinformatik GmbH, Kranzberg, Germany.

1999-2000: GIS Application Specialist/PR Assistant/Intern, InGeo Systems LLC; North Logan, UT

1998: Field Surveyor’s Assistant and Mapping Technician, Schillinger Surveying and Engineering, Eureka, CA

1992-1998 Summers: Worked on numerous plots as a ranch hand; Designed & installed irrigation systems; Designed & implemented planting plans for residential and commercial entities; Construction maintenance – CA, OR, UT, ID

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation Into Qualifying Facility Contracting and Pricing	)

EXHIBIT COALITION/302

QUALIFICATIONS OF EDSON PUGH

March 18, 2013

EDSON R. PUGH, P.E.
General Manager / District Engineer
Deschutes Valley Water District
881 SW Culver Hwy.
Madras, OR 97741 Phone: (541) 475-3849
Email: edson@dvwd.org

EDUCATION

OREGON STATE UNIVERSITY (1979-1982) Corvallis, Oregon
Graduated with a Bachelor of Science in Civil Engineering in June of 1982. Emphasis on Water Resources Engineering.

CENTRAL OREGON COMMUNITY COLLEGE (1977-1979) Bend, Oregon
Accumulated credits toward Bachelor's Degree.

CERTIFICATION

PE Registration (July 1990)
Registered by the Oregon State Board of Engineering Examiners as a Professional Engineer, especially qualified in Civil Engineering.

Water Distribution System Operator II (1988)
Water Treatment Plant Operator I (1988)
Certified by the Oregon Health Authority

EIT Examination (1982)
Certified by the Oregon State Board of Engineering Examiners as an Engineer-in-Training.

EMPLOYMENT

Deschutes Valley Water District (1986 to present)
Currently General Manager / District Engineer with overall responsibilities for a domestic water system and hydro-electric plant. Oversee a $29.7 million biennial budget.

Recent major projects include a 3,000,000 gallon water tank and 17.75 miles of 24” & 20” diameter waterline.

PROFESSIONAL ORGANIZATIONS

OAWU Board Member, American Society of Civil Engineers, American Water Works Association