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April 7, 2006

Via Electronic and US Mail

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 Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities.
Docket No. UM 1129

Dear Filing Center:

Enclosed please find an original and six copies of the Rebuttal Testimony of R. Thomas Beach on behalf of Weyerhaeuser Company and the Industrial Customers of Northwest Utilities in the above-captioned docket.

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided. Thank you for your assistance.

Sincerely yours,

/s/ Anna E. Studenny
Anna E. Studenny

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the Rebuttal Testimony of R. Thomas Beach on behalf of Weyerhaeuser Company and the Industrial Customers of Northwest Utilities upon the parties, shown below, on the official service list by causing the foregoing document to be deposited, postage-prepaid, in the U.S. Mail, or by service via electronic mail to those parties who waived paper service.

DATED at Portland, Oregon, this 7th day of April, 2006.

DAVISON VAN CLEVE, P.C.

/s/ Anna E. Studenny
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF OREGON

UM 1129 (Phase II)

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

REBUTTAL TESTIMONY OF

R. THOMAS BEACH

ON BEHALF OF

WEYERHAEUSER COMPANY

AND THE INDUSTRIAL CUSTOMERS

OF NORTHWEST UTILITIES

April 7, 2006

I. INTRODUCTION

Q. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is R. Thomas Beach. I am principal consultant with the firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 316, Berkeley, California 94710.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION IN THIS PHASE OF THE UM 1129 DOCKET?

A. Yes, I have. On February 27, 2006, I served testimony in Phase II of UM 1129 on behalf of Weyerhaeuser Company ("Weyerhaeuser") and the Industrial Customers of Northwest Utilities ("ICNU"). My experience and qualifications are described in Exhibit Weyerhaeuser-ICNU/301. Both Weyerhaeuser and ICNU have participated actively in the prior phases of the UM 1129 proceeding.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. In this rebuttal testimony I respond to the testimony of the investor-owned utilities ("IOUs")—PacifiCorp, Portland General Electric Company ("PGE"), and Idaho Power—on issues concerning the negotiating parameters and guidelines that the Commission should adopt in Phase II for negotiations between the IOUs and Qualifying Facilities ("QFs") that are larger than the 10 megawatt ("MW") size threshold for eligibility for a standard, tariffed QF contract adopted by the Oregon Public Utility Commission ("OPUC" or the "Commission").

Q. THE COMMISSION CONCLUDED THAT "SIGNIFICANT BARRIERS EXIST TO THE NEGOTIATION OF NON-STANDARD CONTRACTS AND THAT THE DETAILED NEGOTIATION PARAMETERS AND GUIDELINES, AS WELL AS OTHER MEASURES, MAY OVERCOME THESE BARRIERS."[1/] THE ORDER CONCLUDED THAT THE INITIAL PHASE OF THIS CASE FAILED TO ADEQUATELY FRAME OR ADDRESS THE ISSUES CONCERNING BARRIERS TO NON-STANDARD CONTRACTING. AS A RESULT, SUCH ISSUES WERE DEFERRED TO THIS PHASE.[2] HAS THE IOU TESTIMONY PROVIDED THE "DETAILED NEGOTIATION PARAMETERS AND GUIDELINES" REQUESTED IN THE ORDER?

A. In general, the utility testimony lacks the detailed guidelines that Order No. 05-584 requested. For example, PGE's testimony again simply lists the Federal Energy Regulatory Commission ("FERC") pricing factors, with no details on how PGE proposes to incorporate the factors into its negotiations with large QFs, except for a brief discussion of "firm" versus "as-available" contracts.[3/] PacifiCorp's testimony offers some discussion of the FERC pricing factors, but only in general terms concerning how payments should reflect the firmness, dispatchability, and reliability of the QF's generation.[4/]

Weyerhaeuser/ICNU sought to obtain greater specificity from PGE and PacifiCorp in the discovery process. PacifiCorp has listed 13 factors that it will use to adjust the avoided costs offered to large QFs.[5/] PacifiCorp has stated that it will apply each factor on a "case-by-case basis."[6/] PacifiCorp provided a description or example of

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1/ Re Elec. Util. Purchases from QFs, OPUC Docket No. UM 1129, Order No. 05-584 at 11 (May 13, 2005) ("Order No. 05-584").

2/ See id.

3/ PGE/400, Kuns-Sims/11-14.

4/ PPL/404, Griswold/5-6.

5/ Weyerhaeuser-ICNU/305, Beach/3 (PacifiCorp Response to Weyerhaeuser-ICNU Data Request ("DR") No. 11.7).

6/ Id. at Beach/4 (PacifiCorp Response to Weyerhaeuser-ICNU DR No. 11.8).

how the avoided costs would be adjusted for only a few factors, such as line losses and debt imputation.[7/] PGE provided even less information to Weyerhaeuser/ICNU regarding how it would adjust the avoided costs for large QFs. Essentially, PGE stated that it would not provide any information and would adjust the avoided costs on a case-by-case basis, based on the attributes of the QF with which it is negotiating.[8/] There is no way that the Commission or a QF can understand how PacifiCorp or PGE would adjust their avoided costs for large QFs based on the information they have submitted in the record.

PGE's and PacifiCorp's responses and the continued lack of clarity regarding how they would adjust the avoided costs for large QFs is evidence of why the Commission needs to establish firm guidelines. In this proceeding, PGE and PacifiCorp have refused to provide the parties or the Commission with the information necessary to understand how they have adjusted, or would adjust in the future, the avoided costs for large QFs.

Fortunately, the filed testimonies of Staff and Weyerhaeuser/ICNU provide a significant level of detail on guidelines for how the FERC pricing factors should be applied to negotiated contracts with large QFs. Weyerhaeuser/ICNU continues to believe that this is an area in which the more guidance that the Commission can provide, the more artificial barriers to QF development will be eliminated. More specific guidelines will reduce the potential for QF-utility negotiations to reach impasses that either will frustrate QF development or require significant Commission resources to resolve through

[7/] Id. at Beach/6-9 (PacifiCorp Responses to Weyerhaeuser-ICNU DR Nos. 11.10, 11.11, 11.12, and 11.13).

[8/] Weyerhaeuser-ICNU/306, Beach/3-5 (PGE Responses to Weyerhaeuser-ICNU DR Nos. 7.4, 7.5, and 7.6).

the complaint process. I comment below on specific issues concerning the guidelines. Since PGE and PacifiCorp have failed to provide this information, in order to fulfill the Commission's goal of establishing detailed negotiating parameters and guidelines, the Commission is left to choose between the proposals offered by Staff and Weyerhaeuser/ICNU, or having no greater transparency and guidelines than currently exist. The latter alternative does not satisfy the Commission's goals for this phase.

II. SPECIFIC GUIDELINES

Q. PACIFICORP PROPOSES THAT, IF A QF IS LESS DISPATCHABLE THAN THE PROXY PLANT, THE QF SHOULD RECEIVE A LOWER CAPACITY PAYMENT, AND THAT "THIS DEDUCTION SHOULD BE BASED ON THE DIFFERENCE BETWEEN THE AVAILABILITY OF THE QF AND THE PROXY RESOURCE."[9/] PLEASE COMMENT.

A. I agree with PacifiCorp that the key metric for the reliability and dispatchability of a QF is its availability during the utility's peak period. However, it is unclear how PacifiCorp's proposal would actually work to adjust the avoided costs of large QFs. PacifiCorp's proposal raises problems and is confusing because dispatchability and reliability have different meanings and are not always the same. More substantively, I disagree that a QF will only be less reliable than the proxy resource. CHP QFs often demonstrate very high levels of peak period availability.[10/] To the extent that a QF demonstrates peak period availability[11/] that is superior to what is reasonable for the proxy resource, the QF should be rewarded with higher capacity payments than those

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9/ PPL/404, Griswold/6.

10/ For example, the CHP unit at Weyerhaeuser's Albany Mill has achieved availabilities in excess of 99%.

11/ The best measure of peak period availability is the QF's actual generation and achieved capacity factor during the peak period.

based on the costs of the proxy resource. Thus, I have proposed, for example, that if the proxy resource's allowance for on-peak forced outages is 8% (based on industry-standard data), the QF would earn a monthly capacity payment of 100% of the utility's avoided capacity costs if it achieved a 92% capacity factor during the on-peak period of the peak months. As an incentive, the QF could earn an additional 1% bonus capacity payment for each percent by which its capacity factor exceeds 92%. Similarly, the QF's capacity payments would be reduced proportionately to the extent that its capacity factor falls below the 92% standard. The FERC pricing factors should not be a one-way street that only serve to reduce avoided costs for large QFs; QFs also should have the ability to earn additional payments for performance superior to the proxy plant.

Q. STAFF WITNESS SCHWARTZ FINDS TIME-OF-USE ENERGY RATES "A POOR SUBSTITUTE FOR REAL-TIME ECONOMIC DISPATCH," AND SUGGESTS THAT A POTENTIAL ALTERNATIVE FOR ASSESSING THE VALUE OF DISPATCHABILITY IS "STOCHASTIC IRP-TYPE MODELING."[12/] DO YOU AGREE?

A. No. Ms. Schwartz observes that the full value of dispatchability would require avoided cost rates that are tied to real-time prices. This obviously is not practical for a CHP QF, because real-time prices are not transparent to such a facility, which also may have limited operating flexibility due to the thermal requirements of its host. However, this value can be approached if avoided cost rates during the sufficiency period are not based on forward market prices fixed at the time when the IOU files its avoided costs (as is the case today), but instead are time-differentiated and are either: (1) indexed to the natural gas prices that are the key driver of electric market prices (as Weyerhaeuser/ICNU has

12/ Staff/1800, Schwartz/11.

recommended); or (2) indexed to day-ahead on- and off-peak electric market indices (as in the PGE market pricing option, which provides a close approximation of real-time dispatch and which Staff proposes to extend to PacifiCorp). Either of these market-based options would increase the accuracy of the IOUs' avoided cost rates, by more closely aligning them with actual market values. Either of these market options certainly is preferable to the use of fixed forward prices or to the complex modeling exercise that Staff suggests as an alternative.

Q. PLEASE COMMENT ON MS. SCHWARTZ'S CONCERN THAT "DISPATCHABILITY FOR ON-PEAK HOURS ALSO WOULD NEED TO BE ADDRESSED."[13/]

A. Further down on the same page, she addresses her own question, in agreeing with Weyerhaeuser/ICNU that "QF contracts for firm power can provide strong incentives for high reliability through fixed capacity payments (in dollars per kilowatt-year) that are tied to performance during the utility's peak period." If a QF is given a strong financial incentive to produce during peak periods, the QF will dispatch itself to be on-line at the times when the utility most needs the QF's generation.

Q. STAFF AGREES WITH WEYERHAEUSER/ICNU THAT QF GENERATION MAY HAVE AN AGGREGATE VALUE DUE TO ITS DIVERSITY, AND THAT THE SMALLER INCREMENTS AND SHORTER LEAD TIMES OF QF PROJECTS ALSO PROVIDE VALUE TO THE SYSTEM. DO YOU AGREE WITH STAFF THAT THESE VALUES COULD BE MODELED?

A. Yes, I do. It is easy to understand how the small size and geographic diversity of QF generation adds to system reliability. Compare two utility systems that are identical, except that one has a 500 MW proxy combined cycle gas turbine ("CCGT") plant, while

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13/ Id.

the second has ten 50 MW QFs. Assume that each plant has an 8% on-peak forced outage rate. At the time of the system peak, the first system faces an 8% chance of not having the 500 MW CCGT on-line. In contrast, the likelihood that all ten 50 MW QFs will be out at the time of system peak are infinitesimal – one chance in a hundred billion. Given the increasing importance of energy security and reliability to our society, the reliability benefits of smaller-scale, distributed generation must not be ignored.

Q. STAFF ALSO NOTES THAT THE COMMISSION IS ADDRESSING THE VALUE OF RENEWABLE RESOURCES IN MITIGATING FOSSIL FUEL (NATURAL GAS) PRICE RISKS IN DOCKET NOS. UM 1056 AND UM 1182.[14/] **DO CHP QFS ALSO MITIGATE NATURAL GAS PRICE RISKS?**

A. Yes, they do, to the extent that CHP results in the more efficient use of natural gas than if CHP's two products—electricity and useful thermal energy—were produced separately. To the extent that a CHP project can demonstrate that it uses natural gas more efficiently than the proxy CCGT plant (to produce the CHP plant's electric output) plus a stand-alone boiler (to produce the CHP plant's useful thermal output), the CHP project should receive the same natural gas price mitigation value (if any) as a renewable generator that conserves an equal amount of natural gas.

Q. WHAT IS A REASONABLE VALUE FOR THE AVOIDED NATURAL GAS PRICE RISKS THAT RESULT FROM THE DEVELOPMENT OF RENEWABLE QFS AND EFFICIENT CHP QFS?

A. The natural gas savings from renewable or CHP QFs can benefit all gas consumers by reducing the price of gas across the entire market. A 2005 study by the Lawrence Berkeley National Laboratory ("LBNL") examined a wide range of studies on the natural gas consumer benefits resulting from renewable electric generation and energy efficiency

[14/] Id. at Schwartz/14.

programs.[15] LBNL concluded that the regional benefits for gas consumers in the western U.S. gas market from renewable energy and energy efficiency are roughly $5 per MWh of renewable energy production, or, for CHP projects and natural gas conservation programs, $1 per MMBtu of conserved natural gas. Thus, if a CHP project has a net heat rate[16] for electric production of 5,600 Btu per kWh (5.6 MMBtu per MWh) and the heat rate of the avoided resource is 7,600 Btu per kWh (7.6 MMBtu per MWh), then each MWh produced by the CHP unit will save 2 MMBtus of gas use, with a price mitigation benefit of $2, based on the LBNL work. Thus, the natural gas price mitigation benefits of this CHP project amount to $2 per MWh.

Although Weyerhaeuser/ICNU does not take a position in this proceeding on the benefits of renewable energy, these studies demonstrate that if natural gas price mitigation benefits are ascribed to renewable resources, then CHP projects should be recognized as providing similar benefits to the extent that they also conserve scarce gas resources.

Q. DO YOU AGREE WITH PACIFICORP THAT A NEW QF'S IMPACT ON THE UTILITY'S TRANSMISSION SYSTEM SHOULD BE A FACTOR IN NEGOTIATIONS?[17]

A. Generally, I do, and such impacts typically are identified in the interconnection studies for a particular QF project. My first concern with PacifiCorp's discussion of this issue in

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[15] R. Wiser, M. Bolinger, M. St. Clair, Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency, LBNL-56756, Jan. 2005; available at http://eetd.lbl.gov/EA/EMP/reports/56756.pdf.

[16] The net heat rate for electric production is the QF's input fuel use for electric production divided by electric output. The input fuel use for electric production is the total fuel use less the fuel used to produce the CHP project's useful thermal output.

[17] PPL/404, Griswold/7-8.

its testimony is that it is entirely one-sided—the only discussion is of circumstances in which a QF in a transmission-constrained area avoids resources that are less expensive than the proxy resource, or triggers the need for a major transmission upgrade. The converse also can be true—a QF sited in a load packet can displace local generation that is more expensive than the proxy plant but that must run for reliability reasons, or the QF can avoid the need for new transmission into the area**.** To the extent that a CHP QF serves a large on-site load, the QF will avoid the line losses and transmission costs associated with bringing utility power into the area to serve that load. In such circumstances, the QF should be compensated in a negotiated contract at a rate that exceeds the standard avoided cost rate. The Commission also should provide guidance to the utilities and QF developers by specifically rejecting PacifiCorp's position and recognizing that transmission impacts can increase or decrease the avoided costs.

My second concern is that QF developers often lack the means or expertise to review or challenge such transmission studies. To ensure some degree of impartiality, the utility's studies should be based on transmission plans and load flow studies that recently have been reviewed and approved by state regulators or by a regional transmission or reliability organization.

Q. PACIFICORP'S TESTIMONY INCLUDES TWO WITNESSES (MESSRS. STUVER AND SHAH) THAT ADDRESS THE ISSUE OF DEBT IMPUTATION. DO YOU HAVE FURTHER COMMENTS ON THE DEBT IMPUTATION ISSUE IN RESPONSE TO THEIR TESTIMONY?

A. Yes. Messrs. Stuver and Shah testify that debt imputation can be a factor for avoided costs under two possible circumstances: (1) a QF contract is treated as a capital lease under new financial accounting rules; or (2) debt rating agencies impute debt to a utility's capital structure as a consequence of its QF power purchase agreements.[18/]

Mr. Stuver testifies that a QF contract will be analyzed as a lease if: (a) the contract allows the purchaser the right to operate the plant; (b) the contract gives the purchaser physical control over the plant; or (c) it is unlikely that other purchasers will buy more than a minor amount (10% or less) of the plant's output.[19/] None of these are likely to occur in typical QF contracts with CHP projects. I am not aware of any CHP QFs in the western U.S. whose projects are physically operated or controlled by the purchasing utility. Furthermore, even CHP projects that just barely meet the FERC QF efficiency standard of 42.5% must, under FERC rules, sell more than 15% of their Btu output in the form of useful thermal energy.[20/] Thermal energy is not sold to the electric utility, and most CHP QFs also sell a portion of their electric production to their on-site host. Thus, it is extremely unlikely that a CHP QF's sales to the utility will amount to more than 90% of its output. Accordingly, based on the criteria that Mr. Stuver presents, it is highly unlikely that a QF contract will be treated as a lease for accounting purposes.

I have the following observations on Mr. Shah's testimony on how Standard & Poors ("S&P") imputes debt to QF contracts:

- PacifiCorp's cost of capital is impacted by the opinions of a number of ratings agencies, not just by S&P, whose debt imputation methodology PacifiCorp cites

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18/ PPL/404, Shah/1-2.

19/ PPL/700, Stuver/3.

20/ See 18 CFR § 292.205(a)(2).

because it is the most transparent and quantitative. PacifiCorp did not present the opinions of other agencies.[21]

- S&P's most recent Research Report on PacifiCorp indicates that S&P has imputed $570 million to the utility's balance sheet "that predominantly reflects long-term power purchase agreements." There is no indication that this includes all of PacifiCorp's long-term PPAs, or that it includes QF contracts at all. QF contracts are nowhere mentioned in the rating agency reports attached to Mr. Shah's testimony. As I noted in my opening testimony, there are reasons to view QF contracts as less risky than utility-owned resources.

- Mr. Shah attaches to his testimony a Fitch Ratings Special Report on commodity cost recovery at U.S. electric utilities.[22] Although the report identifies PacifiCorp as having "low protection" for the recovery of its power costs, the attached table correctly notes that Oregon is the one state in which PacifiCorp operates that provides a cost recovery mechanism, and that the utility has applied for such protection in its other jurisdictions. In fact, in Oregon PacifiCorp has been allowed to update its power costs on an annual basis through its Resource Valuation Mechanism ("RVM"). PacifiCorp can and has used the deferred accounting statute to recover its excess net power costs in Oregon. S&P has considered PGE's RVM and ability to defer power costs as "quasi" fuel and purchased power adjustment mechanism.[23] A utility also has the ability to obtain authorization from the Commission to implement a power cost adjustment ("PCA") mechanism that includes appropriate deadbands, sharing mechanisms, and earnings adjustments. As PacifiCorp undoubtedly is aware, the Company has requested a PCA in Docket No. UE 173 and a decision is pending. Further, as discussed on page 38 of Order No. 05-584, the Commission has invited PacifiCorp to propose means to hedge its QF costs to the extent that they are based on market prices for natural gas or electricity that can be hedged. Finally, this proceeding is developing Commission-approved policies and guidelines for both standard and negotiated QF contracts; this detailed guidance will assist the utilities in signing QF contracts for which they will be able to recover their costs.

These observations are consistent with the conclusions of my opening testimony on this issue: (1) there is no single formula for calculating the financial impacts of the debt equivalence of QF PPAs; (2) significant judgment is involved in these calculations,

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[21] When asked by Weyerhaeuser/ICNU in discovery, PacifiCorp could not identify any other rating agencies that impute debt related to QFs. See Weyerhaeuser-ICNU/305, Beach/12-14 (PacifiCorp Response to Weyerhaeuser-ICNU DR No. 11.27).

[22] PacifiCorp/805.

[23] Weyerhaeuser-ICNU/307, Beach/2 (S&P Report).

even under S&P's quantitative method; and, most important, (3) regulatory commissions can take significant steps to minimize or even eliminate the alleged debt equivalence issue.

Q. IS THERE ANY INDICATION IN PACIFICORP'S TESTIMONY THAT THE RATING AGENCIES VIEW SMALL AND LARGE QFS DIFFERENTLY ON THE ISSUE OF DEBT IMPUTATION?

A. No, there is not. If the ratings agencies consider QF contracts in imputing debt to a utility (a fact which the utilities have not established), that consideration is in the context of the utility's entire portfolio of power purchase agreements, presumably including agreements both above and below 10 MW. As a result, large QFs alone should not bear the costs of debt imputation. If the Commission believes that debt imputation represents a real and measurable cost to the utility from QF contracts, that cost should be reflected in the utility's filed avoided cost calculations, which apply directly to small QFs and are the starting point for negotiations with large QFs. However, the IOUs' avoided cost filings that the Commission is reviewing in Track I of Phase II do not include debt imputation.[24/] The IOUs have not provided any legitimate reason to treat large QFs differently. In addition, it does not appear that existing QF contracts include an offset for debt imputation.[25/] Finally, because the debt equivalency issue involves the utility's capital structure and the overall risks of its resource portfolio, it is best considered in utility general rate cases, cost-of-capital proceedings, or other cost recovery cases where the

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24/ Weyerhaeuser-ICNU/305, Beach/11 (PacifiCorp Response to Weyerhaeuser-ICNU DR No. 11.25).

25/ Id. at Beach/15-16 (PacifiCorp Responses to Weyerhaeuser-ICNU DR Nos. 11.30 and 11.31).

Commission looks most broadly at the utility's overall risk profile. The Commission should not let the IOUs use debt imputation as a tool to harm large QFs.

Q. PACIFICORP HAS PROPOSED THAT QFS LARGER THAN 100 MW SHOULD BE ABLE TO OBTAIN LONG-TERM CONTRACTS (FIVE YEARS OR LONGER) ONLY THROUGH AN ALL-SOURCE COMPETITIVE BIDDING PROCESS. THE ONLY OTHER OPTION PACIFICORP WOULD OFFER TO SUCH QFS IS ENERGY SALES AT OFF-PEAK PRICES. PLEASE COMMENT.

A. As I discussed in my opening testimony, the key question on this issue is whether the utility solicitations will provide CHP projects and other QFs with a meaningful opportunity to participate. Utility solicitations often are not tailored to the products that QF resources offer. For example, base load CHP projects and intermittent wind farms both have difficulty meeting the dispatch or other operational requirements that utilities typically seek in their solicitations. To be frank, in my experience, utilities are very reluctant to consider CHP projects as a desirable resource to seek in their procurement solicitations. Perhaps that is because CHP projects often serve substantial on-site loads that were previously served by the utility itself. CHP projects thus represent competition for utility services, and the utilities are unlikely to facilitate such competition by purchasing excess power from their market rivals.

Q. STAFF AND PGE SUGGEST THAT THE RESULTS FROM A UTILITY'S RFPS COULD INFORM THE DETERMINATION OF THAT UTILITY'S AVOIDED COSTS. WHAT ARE YOUR OBSERVATIONS ON THE USE OF RFP RESULTS IN THIS WAY?

A. I generally agree with Staff's testimony that RFP results are useful as an input to avoided costs only if the RFP was recently completed and solicited a resource or power product comparable to what QFs avoid. However, Staff also testifies that RFP results only should impact avoided costs during the deficiency period and that QFs may not be able to avoid a large new resource acquired through an RFP. Staff suggests that the results of an RFP may best represent the costs of the next resource that the utility could avoid, presumably after another lengthy sufficiency period.[26] This testimony raises the difficult issue of the timing of avoided cost filings, an issue on which Staff had a different perspective in the initial phase of UM 1129. If the utilities are allowed and encouraged to use RFP results as the basis for updated avoided costs, these updates will occur immediately after the utility has acquired new resources, and the utility undoubtedly will show a lengthy sufficiency period. Thus, the use of RFP results as the basis for avoided costs has the potential to perpetuate the problem of avoided costs that tend to show lengthy sufficiency periods, even if the utility is acquiring, or recently has acquired, new non-QF resources. In the initial phase of this case, Staff objected to a PacifiCorp proposal to allow such updates to avoided costs when new resources are added. As summarized in Order No. 05-584:

> Three parties commented on how often avoided cost rates should be filed with the Commission and reviewed and approved. PacifiCorp recommends that electric utilities be allowed to update avoided costs more frequently than every two years in order to reflect new resources being added to a utility's system. Both Staff and ODOE support maintaining the current filing schedule which requires each utility to make an avoided cost filing every two years coincident with the IRP process. Staff objects to PacifiCorp's proposal, calling it "unbalanced" as it would allow a utility to update avoided costs when a change in circumstances causes the utility to be in a resource sufficient position, but would fail to direct a utility to update avoided costs when a change in circumstances causes the utility to be in a deficit resource position.[27]

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[26] Staff/1800, Schwartz/40-41.
[27] Order No. 05-584 at 29.

Order No. 05-584 acknowledged Staff's and the Oregon Department of Energy's concern by encouraging parties to notify the Commission when it may be appropriate to review avoided costs between the IRP-based, biennial filing deadlines. The Order also noted that this issue may be addressed in the future. Weyerhaeuser and ICNU suggest that, if Oregon desires a robust QF program that makes a significant contribution to the state's resource needs, the utilities should be required to update their avoided costs whenever they determine that they need new long-term supply-side resources, and take an action (such as issuing an RFP) to procure such resources. If such a requirement is in place, then to be fair the utilities also could be authorized to file to revise their avoided costs after an RFP or at the end of a procurement cycle, once their need for new resources has been met.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Weyerhaeuser-ICNU/305

Excerpt of PacifiCorp Responses to ICNU Eleventh Set of Data Requests

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.4

ICNU Data Request 11.4

Regarding PPL/404, Griswold/6, please provide and describe the methodology hat PacifiCorp would use to adjust the avoided costs for a QF larger than 10 MW for dispatchability and reliability.

Response to ICNU Data Request 11.4

Dispatchability and reliability are included as a single adjustment to the standard avoided cost price. In any month, to the extent the QF is less available for dispatch than the proxy resource, the capacity contribution to avoided cost for the QF would be reduced on a linear basis as compared to the proxy. Below an availability level of 85%, the QF would receive no capacity contribution in its on-peak price and receive only off-peak prices for all energy delivered in that month.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.6

ICNU Data Request 11.6

Regarding PPL/404, Griswold/6, if the Commission requires PacifiCorp to calculate the avoided costs offered to large QFs based on the Deadband or Gas Method, how does PacifiCorp propose to adjust the avoided costs for dispatchability and reliability?

Response to ICNU Data Request 11.6

The Company would use the same methodology regardless of the type of pricing structure selected by the QF.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.7

ICNU Data Request 11.7

PPL/404, Griswold/5-6 and Griswold/11 lists four factors that PacifiCorp would utilize to adjust the avoided costs for non-standard QFs and states that there are additional factors. Please identify each of the additional factors that PacifiCorp is aware of that the Company has or intends to utilize to adjust the avoided costs of a large QF.

Response to ICNU Data Request 11.7

PURPA provides that avoided costs are to be determined by a number of factors as set forth in 18 C.F.R. § 292.304(e). All of these factors should be applicable as appropriate for determining the avoided cost price for a non-standard QF contract. The factors are:

a. The system cost data provided by the utility.
b. The QF's availability during daily and seasonal peak periods.
c. The ability of the utility to dispatch the QF.
d. The reliability of the QF.
e. The terms of the contract between the utility and the QF, including the duration of the obligation, termination notice requirements and penalties for noncompliance.
f. The extent to which QF outages can be usefully coordinated with outages from the utility's generators.
g. The usefulness of QF energy during system emergencies, including the ability of the QF to separate its load from its generation.
h. The individual and aggregate value of QF energy and capacity to the utility's system.
i. The smaller capacity increment and shorter lead times for QF deliveries.
j. The extent to which the utility is able to avoid costs associated with capacity additions and fuel use.
k. The variation in line losses between QF purchases and other energy generated or purchased by the utility.

Also, as indicated in the testimony, project location and debt imputation are additional factors that should be considered.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.8

ICNU Data Request 11.8

PPL/404, Griswold/5-6 and Griswold/11 lists four factors that PacifiCorp would utilize to adjust the avoided costs for non-standard QFs and states that there are additional factors. For each of the additional factors that PacifiCorp could utilize to adjust a large QF's avoided costs, please identify how PacifiCorp would decide whether a particular factor should be applied to a large CHP QF facility.

Response to ICNU Data Request 11.8

For each non-standard QF contracts, the Company would determine the applicability of the factors listed in ICNU 11.7 on a case-by-case basis.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.9

ICNU Data Request 11.9

PPL/404. Griswold/5-6 and Griswold/11 lists four factors that PacifiCorp would utilize to adjust the avoided costs for non-standard QFs and states that there are additional factors. For each of the additional factors that PacifiCorp could utilize to adjust a large QF's avoided costs, please identify the methodology that PacifiCorp would use to adjust the large QF's avoided costs.

Response to ICNU Data Request 11.9

Non-standard contracts are, by their nature, negotiated between the QF and PacifiCorp on prices, terms and conditions. In the event that one of the additional factors applied to a QF in a non-standard contract, the parties would determine the adjustment, if any, through negotiations.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.10

ICNU Data Request 11.10

PPL/404, Griswold/5-6 and Griswold/11 lists four factors that PacifiCorp would utilize to adjust the avoided costs for non-standard QFs and states that there are additional factors. For each of the additional factors that PacifiCorp could utilize to adjust a large QF's avoided costs, please provide a historic or illustrative example of how the factor would adjust the large QF's avoided costs.

Response to ICNU Data Request 11.10

In the event that one of the additional factors applied to a QF in a non-standard contract, the parties would determine the adjustment, if any, through negotiations. Below is an example of one such adjustment for line losses.

Under PURPA, as set forth in 18 C.F.R. § 292.304(e), factor k is *"The variation in line losses between QF purchases and other energy generated or purchased by the utility."*

1. A proximity assessment would be completed as part of Schedule 38 when PacifiCorp prepares indicative prices for the individual QF. This preliminary assessment would be based on the physical proximity of the QF to both the proxy plant and the nearest load center. the type of power being delivered to PacifiCorp (i.e. firm dispatchable, non-firm, intermittent, etc.) and the voltage level at which the QF would be interconnected to PacifiCorp's system.
2. Line loss adjustments (both as an increase (cost) or reduction (benefit)) are calculated for a firm thermal QF's scheduled and/or dispatched power and any replacement power the Company must acquire to replace the QF's scheduled but non-delivered power.
3. For QF projects interconnected at the transmission level, the loss percentage factor would be applied per the then-current published PacifiCorp OATT rate at the QF interconnection transmission level. For those rare interconnections at the distribution level, the Company would use the distribution loss percentage factor from the OATT.
4. The Company would evaluate if the proxy resource is geographically closer to the load center than the QF. If the proxy resource is closer to the load area then the QF delivery volume, net of any station service and load self-served, is reduced by the loss factor because the Company incurs additional losses bringing the QF power to the load center in relationship to the proxy resource. If the QF is closer to the load center in relationship to the proxy resource, the delivery volume by the QF that meets the applicability criteria described above, net of station service, is grossed up by the appropriate loss percentage factor.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.11

ICNU Data Request 11.11

Regarding PPL/404, Griswold/7-8, please identify the circumstances under which the Company would experience transmission savings associated with a QF project.

Response to ICNU Data Request 11.11

For a QF to displace planned transmission when its specific operational characteristics and location are considered, the QF must be reliable and dispatchable. If the QF is not reliable and dispatchable and transmission is not constructed, it is possible that the load would need to be shed to maintain system stability during QF outages or reduction in anticipated generating levels. Even if it can be shown that the costs of planned generation resources can be avoided. little if any planned main grid transmission developments may be avoided.
The Company does not believe a QF smaller than 100 MW would have any impact on proposed transmission upgrades. The addition of small QF generators would have very little impact on the scope or timing of these high-voltage transmission plans because of the interconnected nature of the network and the high capacity of the main grid facilities.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.12

ICNU Data Request 11.12

Regarding PPL/404, Griswold/7-8, please identify the methodology that the Company would utilize to adjust a large QF's avoided costs to incorporate the transmission savings.

Response to ICNU Data Request 11.12

PacifiCorp Transmission conducts a system impact study as part of the interconnection process whereby the system study would determine the transmission requirements with and without the QF to reliably serve load. The study and assessment of each QF's reliability levels, ability to support voltage and reactive requirements, and the need for any associated transmission in support of the networks overall reliability is essential. Any transmission that can be avoided or deferred would be eligible for an avoided cost payment to the developer. Conversely, any associated cost of upgrade to transmission is borne by the QF.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.13

ICNU Data Request 11.13

Regarding PPL/404, Griswold/7-8, please provide a historic or illustrative example of how the Company would adjust a large QF's avoided costs because of transmission savings.

Response to ICNU Data Request 11.13

The individual system impact study is complex by nature. Transmission studies use base cases prepared by the Western Electricity Coordinating Council (WECC) as the standardized set of system models. Power flow studies, using the Power Technologies Inc. (PTI) program, are then conducted to determine the system impact of adding the facility in question. The WECC base cases used in these studies represent the generating plants, load distributions, and facilities for all utilities in the western U.S. and Canada. These cases are prepared for various years, seasons and loading conditions. The Company adds in the necessary detailed representation for the cases that are used for the interconnection and integration studies.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.24

ICNU Data Request 11.24

Regarding PPL/404, Griswold/24-25, please identify all the QF contracts that PacifiCorp has entered into as a result of a competitive bid.

Response to ICNU Data Request 11.24

There are none as of the date of this Data Request.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.25

ICNU Data Request 11.25

Regarding PPL/404, Griswold/26. is debt imputation a factor that is included in the standard avoided costs available to QFs under 10 MWs? If so, please identify the specific dollar amount of the debt imputation, as well as the methodology for calculating it.

Response to ICNU Data Request 11.25

No.

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.27

ICNU Data Request 11.27

Regarding PPL/800, Shah/6, lines 13-15, please provide all examples of how credit rating agencies calculate an amount to impute as a debt equivalent related to PacifiCorp's existing QF contracts.

Response to ICNU Data Request 11.27

Standard & Poor's calculates debt equivalence for PacifiCorp in two steps as follows:

(1) Calculate present value of all purchased power obligations (including QF-related) using following rules:

a. Use 100% of purchased power capacity payment obligations

b. 50% of purchased power mixed energy and capacity payment obligations.

c. 100% of purchased hydro power payment obligations

d. Exclude all pure energy payments/obligations.

These rules are referenced in Attachment ICNU 11.27, which is a communication from S&P analyst who covers PacifiCorp credit.

(2) For PacifiCorp, S&P applies a 50% Risk Factor to the present value(s) of payment obligations calculated in Step (1) above. (Reference page 3 of Exhibit PPL-303).

OREGON

ELECTRIC UTILITY PURCHASES FROM QUALIFYING FACILITIES

UM-1129

PACIFICORP

ICNU 11th SET DATA REQUEST

ATTACHMENT ICNU 11.27

ICNU/305
Beach/14

From: Selting, Anne [anne_selting@standardandpoors.com]
Sent: Tuesday, August 10, 2004 4:08 PM
To: Williams, Bruce
Subject: capacity obligations

Bruce
Re your question on debt equivalency we used:

- 100% of PPW capacity obligations
- 50% of PPW mixed energy and capacity and
- 100% of PPW hydro obligations.
- All PPW energy payments/obligations excluded

Anne Selting
Associate Director
Standard and Poor's
One Market, Steuart Tower
15th Floor
San Francisco, CA 94105
(415) 371-5009 ph
(415) 371-5090 fax
anne_selting@sandp.com <mailto:anne_selting@sandp.com>

UM-1129/PacifiCorp
March 17, 2006
ICNU 11th Set Data Request 11.30

ICNU Data Request 11.30

Regarding PPL/800, Shah/9, please provide a historic or illustrative example of how PacifiCorp has calculated the average cost per MWH of rebalancing the capital structure in a QF contract.

Response to ICNU Data Request 11.30

PacifiCorp presently does not have any QF contracts in place with avoided cost adjustments based on a debt imputation adjustment.

UM-1129/PacifiCorp
March 17. 2006
ICNU 11th Set Data Request 11.31

ICNU Data Request 11.31

Regarding PPL/800, Shah/9, please provide all QF contracts that have adjusted the avoided costs based on a debt imputation adjustment.

Response to ICNU Data Request 11.31

PacifiCorp presently does not have any QF contracts in place with avoided cost adjustments based on a debt imputation adjustment.

Weyerhaeuser-ICNU/306

Excerpt of PGE Responses to ICNU
Seventh Set of Data Requests

March 21, 2006

TO: Irion Sanger
Davison Van Cleve, P.C.

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1129
PGE Response to ICNU Data Request 7.2
Dated March 7, 2006
Question 029

Request:

PGE/400, Kuns-Sims/11-12 lists the FERC factors that PGE would utilize to adjust the avoided costs for non-standard QFs. Please identify what other factors PGE has considered in the past to adjust the avoided costs for non-standard QFs.

Response:

PGE considers the FERC factors to be sufficient to appropriately adjust the avoided costs for non-standard QFs, and has not utilized other factors.

March 21, 2006

TO: Irion Sanger
Davison Van Cleve, P.C.

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1129
PGE Response to ICNU Data Request 7.3
Dated March 7, 2006
Question 030

Request:

PGE/400, Kuns-Sims/11-12 lists the FERC factors that PGE would utilize to adjust the avoided costs for non-standard QFs. Please identify the other factors that PGE would consider using in the future to adjust the avoided costs for non-standard QFs.

Response:

PGE considers the FERC factors to be sufficient to appropriately adjust the avoided costs for non-standard QFs, and does not plan to utilize other factors.

March 21, 2006

TO: Irion Sanger
Davison Van Cleve, P.C.

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1129
PGE Response to ICNU Data Request 7.4
Dated March 7, 2006
Question 031

Request:

PGE/400, Kuns-Sims/11-12 lists the FERC factors that PGE would utilize to adjust the avoided costs for non-standard QFs. Please identify the methodologies for each factor regarding the rates for non-standard QFs that PGE has utilized to adjust the avoided costs for non-standard QFs in the past.

Response:

PGE has historically considered the cited factors in developing or discussing potential QF contracts. We have not used a specific methodology for each factor and we are not aware of the existence of a formulistic approach for adjusting avoided costs using these factors.

The factors listed in testimony are the conditions in FERC regulations that the purchasing utility is required, "to the extent practicable," to take into account when determining the rates for purchases of power from QFs. The utility's fundamental obligation is to meet the mandatory power purchase requirement under PURPA with prices that reflect the ability of the utility to avoid costs. The cited factors describe the contractual conditions and characteristics of supply that the utility must consider when pricing. By considering these factors, utility customers should be indifferent with respect to the source of power supply.

The methodology to establish an avoided cost-based price for a particular QF will depend on the characteristics of the project that are related to the cited factors. This will vary on a case by case basis. The commitments made by a QF to deliver firm power, is a primary consideration when determining the value of energy and capacity pursuant to a legally enforceable obligation. The pricing methodology will, in the absence of a firm supply commitment, require that we adjust the avoided cost price to reflect the non-firm characteristics of the QF generation supply. In summary, we will use the supply commitments made by a specific QF to determine how to further develop the avoided cost prices.

March 21, 2006

TO: Irion Sanger
Davison Van Cleve, P.C.

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1129
PGE Response to ICNU Data Request 7.5
Dated March 7, 2006
Question 032

Request:

PGE/400, Kuns-Sims/11-12 lists the FERC factors that PGE would utilize to adjust the avoided costs for non-standard QFs. Please identify the methodologies for each factor regarding the rates for non-standard QFs that PGE intends to utilize to adjust the avoided costs for non-standard QFs in the future.

Response:
See the response to Data Request No. 31. Again, the methodology PGE will use to analyze the attributes of QF generation will vary according to the circumstances of the individual QF.

March 21, 2006

TO: Irion Sanger
Davison Van Cleve, P.C.

FROM: Doug Kuns
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1129
PGE Response to ICNU Data Request 7.6
Dated March 7, 2006
Question 033

Request:

PGE/400, Kuns-Sims/11-12 lists the FERC factors that PGE would utilize to adjust the avoided costs for non-standard QFs. For each factor that PGE intends to utilize to adjust the avoided costs for non-standard QFs, please provide a historic or illustrative example for how the avoided costs for non-standard QFs has been or would be adjusted.

Response:

See also the response to Data Request No. 31. An example of adjusting pricing would be for a QF that does not make any commitments to supply and generates on a non-firm basis. The applicable price will reflect the avoided costs for non-firm power and will not include avoided costs associated with capacity and firm delivery commitments.

Weyerhaeuser-ICNU/307

Standard&Poor's Research Report:
Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western Utilities

Research:
Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western Utilities

Publication date: 14-Oct-2004
Primary Credit Analyst(s): Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

It has been more than three years since the California energy crisis led to the rapid deterioration of credit quality for many western electric utilities. The financial distress that visited public power and investor-owned utilities (IOU) was in part attributable to the absence of fuel and purchased-power adjustment mechanisms (FPPA), coupled with a reliance on the wholesale market for significant supplies. It is not an oversimplification to say that IOUs that emerged relatively unharmed from the energy crisis benefited substantially from FPPAs, while those that suffered the most did not have FPPAs.

The severe market distortions of the California crisis have faded, but FPPAs continue to play a significant role in the financial well-being of western electric utilities. Natural gas volatility, poor hydro conditions in the Northwest, the Southwest's sustained drought, and uncertainty over future generation development are daily reminders that it is increasingly difficult for utilities to sustain their financial health solely through the use of hedging policies and regular general rate case filings. This article examines the progress by major western utilities in instituting FPPAs since the California crisis and comments on FPPA attributes that are important for credit quality.

What is an FPPA?

The overwhelming majority of a utility's expenses are concentrated in two categories--purchased power and fuel. Electric utilities that have the greatest exposure to significant cost swings are those that have sizable gas-fired generation and rely on power purchases that are indexed to market prices. Table 1 illustrates the proportion of 2003 expenses devoted to these two items for 12 western IOUs, and provides a measure of the dependence on gas and power purchases to meet load requirements.

Table 1 Largest IOUs in the West Without Fuel and Purchased-Power Adjusters

	Total fuel expenses (Mil. $) in 2003	Total purchased power expenses (Mil. $) in 2003	Percent of total expenses that is fuel and purchased power	Percent of retail sales supplied with own generation*	Percent of MWh from owned gas generation¶
Puget Sound Energy Inc.	65	649	35.2**	35.6	11.1
Avista Utilities/Avista Corp.	36	148	17.6**	73.8	7.4
Idaho Power/IDACORP Inc.	100	151	35.1	100.6	0.3§
Arizona Public Service/Pinnacle West Capital Corp.	703§§		36.1¶¶	84.5	4.9
Tucson Electric Power/UniSource Energy Corp.	210	65	34.4	136.9	4.0
PacifiCorp/PacifiCorp Holdings Inc.	482	1,213	50.5	107.7	4.1
Nevada Power Co./Sierra Pacific Resources	320	744	60.3	54.6	42.8
Sierra Pacific Power/Sierra Pacific Resources	321	745	53.1**	47.0	59.6
Portland General Electric Co.	1,028§§		60.2	43.0	17.3§

Public Service Co. of New Mexico	141	803	67.3**	134.4	2.1§
Southern California Edison Co.	235	2,786	39.2	63.7	-
Pacific Gas & Electric Co.	0	2,319	70.4**	36.0	1.7§
*Based on data provided by Platt's. ¶Based on company 10K filings, except where indicated by §, in which case data is provided by Platt's. **Combined utility (gas and electric). ¶¶Includes trading and marketing operations. §§Arizona Public Service and Portland General Electric fuel and power expenses are not separately broken out.					

An FPPA allows utilities to automatically flow through retail rates any changes in fuel and purchased-power costs. An FPPA circumvents the need for a utility to file a formal rate case to adjust retail rates to reflect changes in these costs, and significantly increases the probability that an IOU will collect fuel and power costs from ratepayers in full and on a much more timely basis. This is accomplished typically through monthly tracking of costs, with periodic true-ups of a utility's forecast versus actual fuel and power costs, typically annually.

Which Western IOUs Have Instituted FPPA?

In 2000, the largest IOUs in the western U.S. did not have FPPA, and their credit ratings generally suffered as a result of the market disruptions that occurred beginning in 2001 (See table 2) Today, the majority of western utilities have some form of FPPA.

Table 2 Fuel and Purchased-Power Adjusters

Utility/Holding Company	2000 Rating	FPPA in 2000?	2004 Rating	FPPA in 2004?
Puget Sound Energy Inc.	BBB+/Negative/A-2	No	BBB-/Positive/A-3	Yes
Avista Utilities/Avista Corp.	BBB/Negative/--	No	BB+/Stable/--	Yes
Idaho Power/IDACORP Inc.	A+/Stable/A-1	Yes	A-/Watch Neg/A-2	Yes
Arizona Public Service/Pinnacle West Capital Corp.	BBB+/Stable/A-2	No	BBB/Negative/A-2	No
Tucson Electric Power/UniSource Energy Corp.	BB/Stable/--	No	BB/Watch Neg/--	No
PacifiCorp/PacifiCorp Holdings Inc.	A/Stable/A-1	No	A-/Stable/A-2	No
Nevada Power Co. and Sierra Pacific Power/Sierra Pacific Resources	BBB+/Watch Neg/A-2	No	B+/Negative/--	Yes
Portland General Electric Co.	A/Watch Neg/A-1	No	BBB+/Watch Neg/A-2	Quasi
Public Service Co. of New Mexico	BBB-/Watch Neg	No	BBB/Stable/A-2	No
Southern California Edison Co.	A+/Watch Neg/A-1	No	BBB/Stable/A-2	Yes
Pacific Gas & Electric Co.	A+/Watch Neg/A-1	No	BBB-/Stable/--	Yes

Indeed, of the utilities surveyed by Standard & Poor's for this article, four companies have not implemented FPPA-- PacifiCorp (A-/Stable/A-2), Tucson Electric Power Co. (BB-/Watch Neg/--), Arizona Public Service Co. (APS; BBB/Negative/A-2), and Public Service Co. of New Mexico (BBB/Stable/A-2).

PacifiCorp serves portions of Utah, Oregon, Wyoming, Washington, Idaho, and California, has no FPPA in any of these states, and was adversely affected by the California crisis. As a result of an extended coal plant outage and overall reliance on the market for a portion of its power requirements, PacifiCorp deferred $537 million in power costs in 2001 and 2002, of which only $303 million were ultimately authorized for recovery, with Wyoming disallowing the bulk of this difference. As a result of this exposure, PacifiCorp's outlook was revised to negative, and the company was only recently returned to stable. While PacifiCorp has sought an FPPA in Wyoming, the Wyoming Public Service Commission has rejected its request, but did recently approve a settlement resulting from the company's July 2004 filing to increase rates due to rising wholesale power costs. Because about 21% of PacifiCorp's power in 2003 came from purchases, the lack of an FPPA is a credit concern.

In Arizona, the Arizona Corporation Commission (ACC) is allowed to authorize FPPA, but APS' and

Tucson Electric Power's were discontinued in the 1980s. As part of a settlement pending before the ACC, APS has negotiated an FPPA, which it requested in its June 2003 rate case filing. It is unclear whether the ACC will ultimately authorize one. APS' exposure to fuel and purchased-power is significant. In 2002, the ACC halted restructuring of the state's wholesale generation market. While it ordered APS not to sell its generation, APS was uncertain as to how it would procure power to meet retail loads. With electric sales rising about 4% per year, the utility estimates that by the summer of 2007, it will require a nearly 1,200 MW of new capacity, at least a portion of which is likely to be power purchases at indexed prices. Because of APS' significant short position in coming years, an FPPA could lower the utility's risk profile.

Since July 2000, Tucson Electric Power has been under a rate freeze that ends in 2008. Upward movement in gas or purchased power prices that exceeds its current rates does not qualify as sufficient reason to lift the cap. Tucson Electric Power's coal-fired generation provided 96% of the energy needed to serve retail load in 2003, and this low-cost resource base provides somewhat of a hedge against rapid cost escalation. However, a significant forced outage of one of its base load units or a run-up in coal prices with any coal contract reopeners represent exposures for the utility. (UniSource Energy Corp., Tucson Electric's parent, recently acquired the gas and electric distribution assets formerly owned by Citizens Communications. In conjunction with this purchase, the ACC approved an FPPA for these smaller operations, UNS Gas and UNS Electric.)

Public Service New Mexico faces circumstances similar to Tucson Electric Power's. It has no FPPA and in January 2003 negotiated a rate settlement that will lower rates 2.5% in 2005 and then hold rates constant until 2008. The utility owns generation that exceeds native loads, the majority of which is coal and nuclear.

FPPA Design and Implications for Credit Quality

While the use of FPPAs has become common, FPPAs are not uniform in design and consequently, their ability to protect utility credit quality varies. For example, some FPPAs are structured to insure cost recovery in a catastrophic market movement by capping a utility's exposure, but at the same time may have a relatively long lag time for a utility seeking to recover more mundane, month-over-month changes in costs. There are a number of features of FPPAs that are important for credit quality.

Triggers.

From a credit perspective, some of the strongest FPPA are found in the generation and transmission cooperative sector, where wholesale rates are often adjusted monthly. Such timely pass-through of fuel and purchased-power costs is rare in the IOU sector. Instead, IOU FPPA typically track costs in a balancing account, the amounts of which are not reflected in the retail rates as a charge or rebate until a predetermined threshold or trigger is hit. Clearly the lower the trigger, the more frequently the utility is able to adjust its rates to reflect cost changes.

Two contrasting examples can be found in California and Washington. In California, true-ups are not tied to an annual process. Assembly Bill 57, passed by the California state legislature in 2002, provides guidance to the California Public Utilities Commission (CPUC) as to how San Diego Gas & Electric Co., Pacific Gas & Electric Co., and Southern California Edison Co. are to recover procurement costs. Specifically, each year the utilities file their forecast fuel and purchased-power revenue requirements for CPUC review. (These forecasts exclude revenues collected for the California Department of Water Resource contracts). Once the forecast is approved, it is used to set rates. Deviations from the forecasts are tracked in a balancing account called the Energy Resource Recovery Account (ERRA). An adjustment to rates is triggered if the ERRA account is over- or undercollected by 5% of the utility's actual recorded generation revenues for the previous calendar year. This trigger, however, expires Jan. 1, 2006, after which there is uncertainty about what kind of mechanism will exist.

FPPAs may also be tied to dollar thresholds. The Washington Utility and Transportation Commission (WUTC) has approved an energy recovery mechanism for Avista Corp. that requires it to absorb the first $9 million of annual energy cost increases above base rates. Beyond this level, costs are deferred for later rebate and a surcharge is implemented when accumulated deferrals exceed 10% of base retail revenues. Alternatively, utilities may simply be subject to an annual reconciliation process in which actual versus forecast costs are used to adjust base rates. Idaho Power Co. (A-/Watch Neg/A-2) has such an approach.

Sharing mechanisms.

Commonly, FPPAs split the costs (savings) between the ratepayer and shareholder for fuel and purchased power that exceed a forecast range. For example, Puget Sound Energy Inc.'s FPPA requires that it absorb (or may benefit from) the first $20 million of increases (decreases) in actual versus forecast costs relative to baseline rates. For the next $40 million difference, 50% is borne by shareholders in the form of a FPPA adjustment, 10% of the next $80 million, and 5% of any amount more than $120 million, although through a temporary cap, Puget's exposure is limited through mid-2006.

Similarly, though more simply, APS' proposed power supply adjuster seeks a flat 90%/10% ratepayer/shareholder split in costs or savings. The same is true for Idaho Power's power cost adjustment. On balance, FPPAs that provide for fixed or high levels of ratepayer sharing are beneficial to credit quality because they trade upside benefit for downside protection.

Exposure caps.

Utility caps on losses are uncommon, but can be very useful for credit quality as they limit the utility's exposure resulting from extreme market volatility, which could otherwise erode financial health. For example, Public Service Co. of Colorado's (BBB/Stable/--) electric commodity adjustment limits the utility's maximum loss from fuel and purchased power expenses to $11.25 million. For the limited period from July 2002 through July 2006, the WUTC has provided Puget Sound Energy with a cap on its pretax exposure to purchased-power variations of a cumulative $40 million, plus 1% of the overage.

Prudency reviews.

Most FPPAs include caveats that allow the regulator to disallow costs if they are found to be imprudent. How complete this authority is determines how much the FPPA can be relied on, particularly in situations of extreme market volatility or when the utility is forced into the market to purchase replacement power to cover an owned plant outage. APS' proposed power supply adjuster is an example of a mechanism that gives regulators virtually unlimited authority to disallow costs. The ACC may elect to review the prudency of fuel and power purchases "at any time" and any costs flowed through the adjuster "shall be subject to refund if the Commission later determines that the costs were not prudently incurred."

By contrast, language that allows for prudency but provides the utility a high probability of recovery if certain guidelines are followed is preferable. One example is Nevada Power Co., whose recent experience with prudency disallowances of power purchases devastated its credit quality. Specifically, in March 2002, the Public Utilities Commission of Nevada disallowed $434 million of Nevada Power's purchased-power costs incurred during the energy crisis, causing the utility to lose access to bank lines of credit and to the unsecured credit markets. However, in November 2003, the PUCN approved an integrated resource plan (IRP) in which the company will get approval before entering into long-term PPAs. Its short-term power and fuel purchases are adjusted through a new base tariff energy rate, which has features that are similar to an FPPA. While base tariff energy rate costs are still subject to a prudence review, the IRP lays out clear risk-management guidelines, including value-at-risk limits and the use of certain derivative instruments that significantly mitigate the risks of disallowance if the company follows its IRP. Similarly, while California utilities could potentially face a reasonableness review along with its ERRA account, a disallowance is unlikely if the utility follows its procurement plans, which are preapproved by the CPUC.

How Quickly Recovery Is Collected in Retail Rates

Timeliness of recovery is important, as it can have implications for liquidity. California now has one of the strictest rules for timely response. The CPUC must act on a utility's request for an increase (assuming the trigger has been met) within 60 days of a filing. However, the CPUC has discretion in determining over what time period over- or under-collected balances are amortized.

In Arizona, deferrals could theoretically accumulate for long periods if amounts for collection exceed a surcharge cap but fall short of a safety net provision. If approved, APS' proposed PSA would be preset at a base rate of about 2.1 cents per kilowatt-hour (kWh). While actual costs above or below this level are tracked in a balancing account, true-ups occur only at year's end. At that time, rates are adjusted, but adjustments are constrained by the fact that they may not increase or decrease by more than 4 mills per kWh. However, APS may request the ACC to implement a special surcharge if the account reaches plus or minus $50 million at any time.

FPPA sunsets.

From a credit quality perspective, it is important to note that FPPAs are rarely established as a permanent component of a utility's rate structure. Thus, Standard & Poor's is mindful that FPPAs can be weakened or eliminated altogether once their initially authorized period expires. In the West, many of the FPPAs that have been implemented since 2002 have a sunset provision. For example, Puget Sound Energy, Public Service of Colorado, and California's three largest IOUs have FPPAs that expire Jan 1, 2006. If APS' proposal is approved, it will be in place for five years, at which time the ACC will conduct a review and determine whether it should continue. Another useful example is Portland General Electric Co. (BBB+/Watch Neg/A-2). The Oregon Public Utility Commission authorized a temporary FPPA to recover deferrals incurred in 2001 and 2002. The mechanism was discontinued in 2003. Today, the company has a quasi-FPPA; i.e., rates are updated annually through a resource valuation mechanism process, but if during the year the utility is unable to collect all of its costs through rates, it must make a special filing before the commission to recover the shortfalls. This experience highlights the fact that while many utilities may be currently protected through FPPA, this may not be the case for long.

Are FPPA the Holy Grail of Utility Credit Quality?

Standard & Poor's is frequently asked what weight is given to FPPA. It is clear that continued gas price volatility and upward trends in historically stable coal prices underscore the importance of FPPAs. Some western IOUs have sold their generation and will continue to rely on power purchases to meet retail load growth far into the future. However, it is also clear that FPPAs vary substantially in their ability to protect utilities daily and under catastrophic market movement. Moreover, it is critical to note that FPPAs are not a substitute for supportive regulation; the regulator's ability to disallow costs through ex-post prudency review, regardless of the existence of an FPPA, is a fact of life for utilities. But to the extent that an FPPA is transparent and well structured, regulators are likely to be less inclined to disallow a utility's fuel and purchased-power costs.