**BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON**

PACIFICORP

**UM 1129
PHASE II**

In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities

Direct Testimony and Exhibits

February 2006

Case UM-1129
Exhibit PPL/303
Witness: Nathalie O. Wessling

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Nathalie O. Wessling

Security

February 2006

Q. Please state your name, business address and occupation.

A. My name is Nathalie O. Wessling. My business address is 825 NE Multnomah Street, Suite 1800, Portland, Oregon 97232. I am employed by PacifiCorp (the Company) in the Credit Department.

Q. Briefly describe your education and business experience.

A. I have a Bachelor of Science degree in Marketing from the University of Maryland. I have worked in the Company's corporate Credit Department for the past nine years where my responsibilities have included establishing credit procedures and controls, measuring credit exposure and monitoring counterparty credit risk in connection with wholesale energy trading. Prior to this position, I was a Lease Portfolio Manager for seven years with Pacific Venture Finance, a subsidiary of PacifiCorp Financial Services.

Q. Please describe your current duties.

A. I am responsible for providing credit support to the Origination group within the Company's Commercial and Trading Department and ensuring counterparty credit risk is appropriately mitigated.

Q. What is the subject matter of this testimony?

A. I will address issues identified in the UM 1129 – Phase II Adopted Issues List regarding PacifiCorp's default security provisions for nonstandard QF contracts.

Q. With regard to Issue 1(c), how should "firm" or "non-firm" supply commitments be defined and differentiated through contractual default and damages provisions?

A. In this context, "firm" supply commitments indicate the requirement of a QF to perform and to provide a certain minimum amount of power which the Company can depend upon and use for its resource planning. In this context, "non-firm" supply commitments indicate no obligation to deliver and no legal recourse by the Company against the QF for such failure to deliver. If a QF is providing non-firm power on an as-delivered basis, and there is not a capacity payment being paid by the Company or a minimum expectation of energy to be delivered, then credit and security requirements do not apply. However, for firm commitments, contractual default and damages provisions are needed to protect the Company and its customers.

Q. With regard to Issue 2, in the event of the inability of a QF to establish creditworthiness, how should an appropriate amount of required default security be determined?

A. For a nonstandard QF (one that has a nameplate rating greater than 10MW), the Company proposes default security requirements similar to those that it proposed in the compliance phase of this case for a QF that is 3MW or greater in size. The proposed requirements for negotiated QF PPAs are as follows: Unless otherwise agreed to by both parties in writing, the amount of default security shall be an amount sufficient to replace a minimum of twelve (12), and a maximum of thirty-six (36), average months of replacement power costs over the term of the contract, and shall be calculated by taking the average, over the term of the contract, of the positive difference between (a) the monthly forward power prices at [specify the POD], multiplied by 110 percent, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) the Minimum Annual Delivery divided by twelve (12), and then multiplying this resulting amount by (d) the number of months required; provided, however, that the amount of default security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on the Seller's average monthly volume over the term of the contract and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37.

The multiplication of the forward market prices by 110%, as well as the three-month minimum provision, is to protect the Company's ratepayers in the event of a movement in forward market prices.

Q. What is the Company's position on a cap on default losses that can be recouped, pursuant to future QF contract payment reductions?

A. This issue (Phase II Issue 6) was addressed in the compliance filing portion of this case, and the Company's position has not changed. The Company does not believe there is sound rationale for having any cap on default losses that can be recouped. A cap could subject the Company and its ratepayers to additional expenses for power should the replacement power costs incurred during the default period exceed some established cap. Moreover, in Order 05-584, the Commission made the "recoupment through reduction" provision applicable only to standard contracts, and the Company believes that as to negotiated contracts, it would be inappropriate to mandate such a provision that would only allow the utility to recoup default damages by reducing future payments. Such a provision would inappropriately shift risk from the QF to the Company's customers.

Q. Does this conclude your testimony?

A. Yes.

Case UM-1129
Exhibit PPL/404
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Bruce W. Griswold

Phase II Issue Position Summary

February 2006

Q. Please state your name, business address and position with PacifiCorp dba Utah Power & Light Company (the Company).

A. My name is Bruce W. Griswold. My business address is 825 N. E. Multnomah, Suite 600, Portland, Oregon 97232. I am a Manager in the Origination section of the Company's Commercial and Trading ("C&T") Department.

Q. Have you previously testified in this proceeding?

A. Yes. I provided rebuttal testimony for Phase I issues.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- provide the Commission with an overview of the Company's case on Phase II issues,
- discuss the appropriate adjustments to the calculation of prices for individual qualifying facilities ("QFs") that are over 10 MW,
- describe the Company's proposal for purchases from QFs 100 MWs or larger in size, and
- address renewable QF issues.

My testimony is organized according to the OPUC staff consolidated list of Phase II issues issued October 28, 2005.

ISSUE 1. DEVELOPMENT OF NEGOTIATION PARAMETERS AND GUIDELINES FOR NONSTANDARD QF CONTRACTS.

Q. **Issue 1.a. What contract length should Qualifying Facilities larger than 10 MW be entitled to? [Order No. 05-584 at 17]**

A. The Company believes that the maximum term length of up to twenty (20) years as described in Order 05-584 represents an appropriate balance between a term that allows the QF to secure financing and the risks that accompany long range power price forecasting. Because of the dynamics of energy prices in the utility industry, the longer the contract term, the greater the risk to the Company and customer of incurring an uneconomic power purchase agreement. The fundamental objective of the term of a QF contract is to enable eligible QFs to obtain adequate financing but also minimize the possible divergence of the QF contract prices from actual avoided costs.

Furthermore, once the term of a QF's contract expires, they may choose to continue to make sales to the utility (if the PURPA obligation to purchase is still in-place) or sell to third parties, which would allow the QF the opportunity to recover its investment if the plant is operational. The contract term does not limit the period of time in which a QF may recover its investment, it merely limits the time period for which pricing is based on a snapshot projection of avoided costs. In other jurisdictions where the Company operates, twenty years is the maximum QF contract length.

Q. Issue 1.b. How should QF power supply commitments differentiate between "as available" and "legally enforceable obligations" for delivery of energy and capacity?

A. PacifiCorp views "as available" and "legally enforceable obligations" as terms and conditions that should be addressed on a contract specific basis and are fundamental to power procurement. These terms and conditions are, in fact, what the Company utilizes in determining the value of proposed transactions with wholesale counterparties. Contracts providing the delivery of energy on an "as available" basis are evaluated as a non-firm contract, and should be priced accordingly. FERC regulations provide that the pricing for such deliveries be based on the avoided cost at the time of the delivery, which should only be an energy price. On the other hand, if the QF enters a "legally enforceable obligation" to deliver a firm product, the pricing and other contractual provisions would reflect the firm nature of the obligation. FERC regulations provide that the pricing for a "legally enforceable obligation" be based on the avoided costs calculated at the time the obligation is incurred; that is, when the QF contract is entered into. Just like any counterparty with which the Company contracts for firm power, a QF who negotiates with the Company and signs a contract for firm delivery understands its obligations under the terms and conditions of the QF contract. The Company then can incorporate the firm obligation when it establishes its load and resource position. The price that is evaluated and paid to the QF is the avoided cost of a dispatchable resource on a fixed basis for the term. The Company is relying on the power to be delivered as agreed by the parties in the contract, and if it is not delivered, the QF should be held responsible for no less or no more than what the contract specifies.

Q. Issue 1.c. How should "firm" or "non-firm" supply commitments be defined and differentiated through contractual default and damages provisions?

A. The Company believes that "firm" versus "non-firm" are fundamental to both standard and non-standard agreements. As discussed earlier, the "firm" delivery commitment by the QF reflects a commitment to perform and to deliver a minimum amount of capacity and energy which the Company includes in its load and resource position. Failure to provide a firm delivery constitutes a default, and should result in recovery of damages to ensure Company and customer neutrality.

A "non-firm" delivery commitment by a QF is a "put" held by the QF on the utility's system. The QF holds the option but no obligation to deliver, while the Company has a PURPA obligation to purchase as delivered, but no legal recourse in the event that the QF fails to deliver. As such, the value of the "non-firm" power to the Company must be reflected in an adjustment to the avoided cost payments. PacifiCorp witness Nathalie Wessling addresses the different damages and default provisions for firm versus non-firm contracts.

Q. Issue 1.d. How should avoided costs be adjusted for factors, such as those described in 18 CFR § 292.304, for a Qualifying Facility's specific power supply attributes and commitments?

A. The starting point for prices available to a QF greater then 10 MW is the Company's standard avoided costs as determined per Order 05-584. These standard avoided cost prices assume that a QF will have optimum operating characteristics and will impose no additional integration costs on the Company's system, above that of system interconnection. The second step is to identify, pursuant to PURPA, the level of costs the large QF actually allows the Company to avoid. PURPA identifies a number of factors that affect rates for purchases from QFs, including:

a. *The type of power being delivered to the utility by the QF project.* One of the key factors affecting the prices paid to the QF is the type of power delivered to the utility. Rates for purchases should reflect the duration and firmness of the energy and capacity provided. When the QF has contractually committed to make capacity and energy available on a firm basis, the QF is entitled to capacity and energy payments that reflect the energy and capacity costs it allows the Company to avoid. If the QF will only agree to make power available on a non-firm basis, it is only entitled to an energy payment. In instances where the QF decides when and if the Company is to receive energy, the Company is unable to rely on the energy for its load and resources position and as a result, the QF should not be entitled to capacity payments for any period.

b. *The QF's availability during daily and seasonal peak periods.* The Company's standard avoided cost prices assume that energy and capacity from a QF will be available during the Company's daily and seasonal peak periods. If a QF, greater than 10MW, cannot, or will not commit to provide capacity during peak periods, no capacity payments should be made to the QF project for those periods.

c. *The ability of the utility to dispatch the QF.* The ability of a utility to dispatch QF generation on demand or provide direction to the QF on how to dispatch (consistent with the proxy resource) would be a key consideration in establishing avoided costs. Any QF that offers to sell PacifiCorp capacity and energy with dispatchability lower than the proxy should have a decreased capacity payment. The methodology for determining this deduction should be based on the difference between the availability of the QF and the proxy resource.

d. *The reliability of the QF.* The specific rates paid to the QF should be adjusted to reflect the actual, or estimate, of the facility's operating reliability and capacity production capability (such as heat rate or capacity degradation) compared to the proxy resource. This adjustment is an adjustment to the standard avoided cost capacity payment because it affects the extent to which PacifiCorp can rely on the QF resource in the load and resource position going forward. This adjustment is included in item "c" above in the calculation of the adjustment, if any, for the monthly availability.

FERC regulations list additional factors that might be taken into consideration for a specific QF project. Whether such factors apply, and if so, how they should be addressed for purposes of determining avoided costs will be considered on a case-by-case basis for individual QFs, so as to take into account the particular circumstances presented by the QF.

Q. What factors should be considered in determining the avoided cost price paid to an individual renewable QF project?

A. The factors I discussed above with respect to QFs generally also apply to renewable QF projects. For example, with respect to a wind project; performance is based on mechanical turbine availability in addition to wind performance (speed and variability). I will discuss the mechanical availability and integration costs later as separate issues. The probability that the wind resource may not be available when needed to meet peak load is significant. As a result, a separate calculation of planning reserve contribution is required and should reflect the variability of wind generation during the system peak. Several factors drive the measure of wind's capacity contribution to PacifiCorp's system. The first of these factors is site performance. For example, wind speed and duration are characteristics which directly impact site generation and the capacity factor of a particular wind site. Second, seasonal and time-of-day patterns determine wind contribution during peak hours. Third, the composition of the existing resource mix as well as volatility in system loads and resources affect how wind's capacity contributes to the Company's system.

Q. Are there additional factors that should be considered in determining avoided cost prices for a QF greater than 10MW?

A. Yes. There are at least two other factors to consider. The first is project location. In those cases where a resource is added to PacifiCorp's system and there is insufficient load nearby to absorb the resource, the added QF power must be moved elsewhere to be useful to the system. This is primarily expected to be the case in the off-peak time period when customer loads are normally lower, but also may occur with the addition of numerous QF projects or a large QF project in a concentrated load area or transmission constrained location. If there is inadequate existing transmission capacity to move the power elsewhere in the system, the Company has two options: back down use of its own low-cost resources being delivered to the load in the area or upgrade the transmission system to accommodate moving the resource output to load elsewhere. In the worst-case scenario, where the Company resources to serve that load area have all been curtailed and transmission out of the load area is inadequate, the Company may be faced with not being able to accept QF power. In the first case, the avoided cost that the QF receives should be adjusted down to reflect the Company's obligation to accept the QF's higher cost power and back down its lower cost resources such as a coal plant. If a new QF resource has triggered a transmission system upgrade, the QF should bear the cost of the transmission system upgrade to move their power out of the load pocket to serve the network load. While the Company recognizes that locational transmission constraints and the need for transmission upgrades should not prevent project development, the incremental cost reflecting the constraint or upgrade should be borne by the QF developer and not the customer, as is presently the case. Analysis of transmission system constraints and the cost of options for dealing with those constraints should be made available to QF project developers as part of the QF pricing and contract process so that appropriate adjustments can be made in determining the avoided cost.

The second issue is debt imputation. I will briefly outline this issue later in my testimony and both Mr. Shah and Mr. Stuver will provide separate testimony on the accounting standards that should be considered in determining the avoided cost price for an individual QF.

Q. Issue 1.e. Regarding PacifiCorp's Schedule 38 for Qualifying Facilities larger than 10 MW, are the procedures for negotiating avoided costs, schedules for negotiations, and the information to be exchanged by PacifiCorp and the Qualifying Facility reasonable?

A. Yes. First let me review Schedule 38 and the basis for procedures as outlined and then explain why each step of the procedure is reasonable and necessary.

Q. What is the purpose of Schedule 38?

A. Schedule 38, Qualifying Facilities Procedure, was the result of a work-group that was established in Utah three years ago in a Docket addressing issues similar to those we are addressing here. The work group included many parties, similar in nature to the parties in this Docket, who participate in the development and negotiation of the procedures in this tariff. Schedule 38's general purpose is to provide the steps and schedule that both the Company and a proposed QF work through to determine indicative or estimated avoided costs for a proposed QF project. The tariff very clearly lays out the information required by the Company to prepare indicative prices for a proposed QF project. Even a developer of a QF project in the conceptual stage should have most of the information collected because it is necessary for the design and construction of the QF project. As the procedure outlines, QF projects that provide greater detail regarding their projects have a much lower probability of experiencing a delay in the development of indicative prices.

Q. Has Schedule 38 worked as it was intended?

A. Yes. Schedule 38 has worked well in Utah where it was developed. Even in our other states where we have no Schedule 38, the Company uses this Schedule as the road map with the non-standard QF. It provides the QF developer a clear understanding to secure indicative prices from the Company and determine their own project economics. If they wish to proceed with the project, there continues to be a procedure that both parties follow throughout the contract negotiations. To work effectively, Schedule 38 requires specific and detailed information from the QF regarding their proposed project. A QF developer that comes to the Company with vague requests or insufficient details will become frustrated, as the Company is not in a position to design and size QF projects.

Q. Has Schedule 38 been a deterrent to QF development?

A. No. To the contrary, the Company has had many requests in Utah and other jurisdictions since 2003 for QF indicative pricing that have used the Schedule 38 procedure. Several are now on-line and operational. All of these QF developers and/or customers came to PacifiCorp with a very specific project and the documentation to support the project.

Q. Issue 1.f. Can the utilities adjust the avoided cost calculations for Qualifying Facilities over 10 MW based on factors that have not been approved by the Oregon Public Utility Commission?

A. Yes, if we are to establish prices for large QFs that are actually representative of the utility's avoided costs. As I discussed above, there are a series of factors allowed under PURPA regulations for determining the avoided costs that should be paid based on the specific project operating characteristics. It would be contrary to the goal of determining avoided costs if the utility could not consider a project-specific factor that has an actual impact on the costs the project allows the utility to avoid. If the QF disputes the utility's determination of the impact of a factor, it has the opportunity to bring that dispute to the Commission for resolution. But it would not be reasonable to require that a factor be ignored just because it isn't on a pre-approved list.

Q. Are the Company's proposed adjustments discretionary?

A. No. Although intervening parties have stated in prior testimony that the adjustments described are discretionary and unclear on the part of the utility, the fact is that each individual QF contract is subject to review for prudency by the Commission in rate case proceedings, and the Commission can decide if the adjustments were just, reasonable and achieve customer neutrality. Regardless of the methodology for determining the starting-point avoided cost prices, it is important for the Company to apply adjustments as allowed by PURPA to reflect the individual operating characteristics of the individual QF so that the Company is paying the appropriate price for the delivered resource.

ISSUE 3. FURTHER EXPLORATION OF HOW THE CALCULATION OF AVOIDED COSTS SHOULD REFLECT THE NATURE AND QUALITY OF QF ENERGY. SPECIFICALLY:

Q. Issue 3.a. How should firm vs. non-firm commitments and integration of intermittent resources affect the calculation of avoided costs?

A. I will address the firm vs. non-firm commitment portion first. As I have discussed earlier, the Company believes there is a clear difference between "firm" and "non-firm" commitments. Prices for QF purchases should reflect the duration and firmness of the energy and capacity provided by the QF. When the QF has contractually committed to make capacity and energy available on a firm basis, the QF is entitled to capacity and energy payments that reflect the energy and capacity costs the QF allows the Company to avoid. If the QF will only agree to make power available on a non-firm basis, the QF is only entitled to an energy payment.

Q. Please explain how integration of intermittent resources affects the calculation of avoided costs.

A. System integration costs are costs incurred by the utility and should be included as part of avoided costs under both standard and non-standard QF contracts, specifically as they apply to intermittent resources such as wind. These issues apply whether the wind resources are acquired as QF contracts or through commercial transactions; however, commercial transactions through a RFP or direct bi-lateral negotiation provide for price adjustment mechanisms to be taken into consideration. In the Company's renewable RFP, the Company does compare renewable project specific operating characteristics and location in determining the overall cost effectiveness of the resource proposals which includes the cost to integrate the resources. On a general level, all utilities face the same issues of integrating an intermittent resource into their portfolio.

Wind resource output depends on wind availability and speed. Wind speeds cannot be predicted with any real accuracy since the wind often fluctuates significantly within the hour. As part of the Company's study in the 2003 IRP, and through PacifiCorp's experience with several wind farms, PacifiCorp's system planners and operators have determined that these variations increase the overall operating costs of the PacifiCorp system. System operators maintain a balance between the system supply and demand for power on a continuous basis. The balancing relies on the operating characteristics of power plants in PacifiCorp's resource mix and the operation of these plants through computer automation. The variability of wind plant output causes additional volatility in system balance that must be compensated by other power plants to maintain system balance, causing power plants to further deviate from economically optimal operating conditions. Additionally, it is important to understand that the key issue is not whether a system with a significant amount of wind capacity can be operated reliably, but rather to what extent the system operating costs are increased due to the variability of the wind and/or what other system upgrades must be put in place to integrate the resource in question. A study was performed by the Company during its IRP process to estimate the integration cost of a wind resource added to its system. These costs are referred to as ancillary services costs such as incremental reserve or system dispatch costs (termed "imbalance" costs in the 2003 IRP). Incremental reserves are the cost associated with holding additional operating reserves to maintain system reliability as greater amounts of wind resources are added and there is an increased volatility in system load imposed by the variability of wind plant output. System dispatch costs capture the increased operating costs associated with operating other power plants at other than optimum economic levels to balance the system with the addition of rapidly changing wind resources. In the 2003 IRP, the cost of incremental operating reserves for a wind site with a capacity factor of 30% was determined to be $2.72/MWh. Combined with the $3.00/MWh estimate for incremental system dispatch, the total integration cost was approximately $5.50/MWh. An update to the costs was done for the 2004 IRP in which the assumption for imbalance costs have remained unchanged at $3.00/MWh but the cost of incremental reserves has been updated for new market prices. In the current updated IRP the cost of integration is estimated to be $4.64/MWh and escalates over time as more wind resources are added. Absent site specific integration costs, PacifiCorp considers these costs to be a reasonable approximation of the costs of integrating wind and should be included as a cost the Company incurs in the calculation of avoided cost for wind resources.

Q. Issue 3.b. Costs and contractual provisions necessary to address purchases from QF projects that are located outside of the utility's control area. Is the Company addressing this issue at this time?

A. No. Although my rebuttal testimony filed in the Compliance portion of this case addressed the off-system contract issues, the Company understands this issue is to be addressed in separate testimony on a different schedule.

ISSUE 4. FURTHER EXPLORATION OF A MECHANICAL AVAILABILITY GUARANTEE (MAG).

Q. Issue 4. Are avoided cost prices affected by a Mechanical Availability Guarantee?

A. No. The avoided cost prices are based on the approved methodology set by the Oregon Commission. The Mechanical Availability Guarantee ("MAG") is a performance standard proposed by PacifiCorp for inclusion in power purchase agreements with intermittent resources, such as wind, and only affects the dollar payment to the QF to the extent it does not meet its contractual commitments of the MAG.

Q. What is the performance metric used by PacifiCorp in current standard contracts in Oregon?

A. The Company standard QF contract sets an annual minimum and maximum delivery of energy. The QF provides a monthly forecast of deliveries that is the basis for the minimum and maximum. In the event the QF does not meet its annual minimum, the QF is responsible for the volume of replacement power to meet its annual minimum at the price difference, if any, between its contract price and the replacement power price. While this type of structure works for thermal plants, the Company felt it was punitive on those resources that had no control over their motive force, primarily wind.

Q. How does a Mechanical Availability Guarantee (MAG) work?

A. As I mentioned above, the MAG is intended to be a performance commitment in power purchase agreements with intermittent resources. The MAG is founded on the simple premise that consistent high mechanical availability of a wind turbine results in more predictable energy delivery. The converse is also true – if a wind QF is unreliable due to poor mechanical availability of the turbine(s), predictability will be poor, even if the QF accurately forecasts the wind resource. PacifiCorp's MAG approach recognizes that a wind QF cannot accurately forecast monthly generation output months in advance, and therefore grades the QF's performance by what it can control – the mechanical availability of the turbines. The MAG provisions require that a QF's average availability is equal to or exceeds a specific availability threshold, for example: it might be set at 82 percent for year 1; 93 percent for years 2-10; and 90 percent for years 11-20. With each passing year, PacifiCorp and the QF expect to gain more confidence in the dependable annual energy production of the facility—a number critical to PacifiCorp's long range resource planning. Without the MAG provision, PacifiCorp would have less confidence in the facility's minimum annual output because the QF would have less incentive to invest in the reliability and maintenance of the turbines. In the event actual deliveries demonstrate that monthly QF output is predictable, PacifiCorp will make use of that information as well.

Q. Please describe the mechanics of the MAG.

A. First, let me define mechanical availability. Mechanical availability is the percentage of time that the facility is actually producing net output energy, compared to the total amount of time that the facility could have produced net output energy had all turbines been fully operable. The total amount of time that the facility could have produced net output energy is determined by taking the total minutes in the measurement period and deducting the total number of minutes of non-generation due to inadequate or excessive wind, force majeure, and scheduled maintenance. Where the facility is comprised of multiple wind turbines, the average availability of the facility is taken to be the weighted average of the availabilities of each individual turbine, calculated using the same method. Using verifiable QF collected wind data at the site and metered output of the wind turbine, the Company can determine the availability of the QF turbines for any period of time defined in the QF Agreement. If we use a calendar year as an example, then the availability would be determined for the QF wind farm for the calendar year using the collected wind data and metered output. It would be compared against the threshold availability level in the contract and to the extent the QF did not meet the threshold level of availability, then the QF would pay damages on the difference between actual and the threshold level for that calendar year. Damages are calculated similar to the damages for under delivery included in the existing standard contract but are based on meeting the availability threshold. For example, the damages for the calendar year would equal the difference of the actual availability to the threshold availability times the annual expected delivery volume in MWh times the positive difference of the contract price and the replacement power price or as shown below in equation form.

$$Damages = (Avail_{TH} - Avail_{ACT}) * Expected\ MWh * (RPP - CP)$$

Where:

- $Avail_{TH}$ is the availability threshold set in contract
- $Avail_{ACT}$ is the availability as measured for the wind farm
- Expected MWh is the annual expected energy output of the wind-farm based on monthly forecast in contract
- RPP is the replacement power price as defined in contract
- CP is the contract price in contract

Q. Why is the MAG better for intermittent resources?

A. The MAG approach should yield more total energy. Under the minimum delivery approach in the standard contract, the QF is paid the full published rate if it delivers any volume over its monthly minimum delivery. The damages provisions of the minimum delivery gives the QF an incentive to submit unrealistically low delivery targets in order to reduce its risk of incurring the under-delivery penalty. There is no such incentive under the MAG approach. Under the MAG approach, the QF is charged for damages under the MAG only if it fails to achieve the availability threshold. Compared to the minimum delivery method, the MAG approach gives the QF greater incentive to maximize its production by maximizing its availability. Over the life of the contract, the MAG approach can reasonably be expected to yield more energy from the same facility than under the minimum delivery method. The MAG approach should yield fewer contract disputes. Under the minimum delivery approach, the QF's minimum delivery target may be understated if the QF believes it would experience a forced outage due to equipment failure. No such adjustment will be made, however, if the forced outage resulted from an event of force majeure or by neglect, disrepair or lack of adequate preventative maintenance of the wind facility. The difficulty of determining whether an outage should be excused under this provision, coupled with the large amount of money potentially at stake, makes fertile ground for repeated disputes whether a given outage should or should not be excused. Under the MAG approach, the QF bears the risk of equipment failure, whether or not such failure resulted from neglect. Relative to a minimum delivery method, the MAG approach for determining whether non-availability should be excused is straightforward, predictable, and less likely to give rise to contractual disputes over the cause of forced outages.

Q. **Should a Mechanical Availability Guarantee be applied in all QF contracts?**

A. No. The MAG was developed to be used with intermittent resources that have little or no control over its motive force, primarily the wind industry where power is only generated when the wind blows. It was not developed to be used with thermal resources such as gas turbines or steam turbines that operate on purchased or controllable fuel supplies. For example, a biomass QF that is an integral part of a wood products facility should not have its contract performance based on a MAG. The wood products plant generates its own fuel to supply the generator and in the event it does not have sufficient fuel to operate the generator to a contractually committed level, then it can purchase that fuel in the open wood waste market. I have not seen that option afforded to the wind industry.

ISSUE 5. FURTHER EXPLORATION OF MARKET PRICING OPTIONS AND ALTERNATIVES TO USING NAMEPLATE CAPACITY TO DETERMINE THE SIZE OF A QF PROJECT FOR STANDARD CONTRACT ELIGIBILITY PURPOSES

Q. Would you explain the difference between the current Commission approved avoided cost and the market pricing option proposed by Issue 5?

A. Yes. The Commission methodology required that avoided costs during the sufficiency period be based on market transactions and the CCCT proxy prices during the deficiency period. The market prices are determined at the time the Company files and the Commission approves the Company Schedule 37 avoided cost prices. Avoided cost prices including the market prices during the sufficiency period remain fixed during the term of the QF contract. For the proposed market pricing option, QF prices are tied to a market index or combination of market indexes so that the QF price will change from month to month.

Q. Issue 5a. Should PacifiCorp offer a market pricing option?

A. No. If a market pricing option were adopted it would place more risk on the Company of not recovering additional net power cost variations from the level included in rates than the substantial level of risk the Company already bears.

Q. Would the adoption of a Power Cost Adjustment Mechanism (PCAM) solve this problem?

A. The adoption of a PCAM would only solve this problem if the mechanism provided a reasonable level of sharing whereby the Company has an expectation that it will recover its expected net power costs over the long-run.

Q. Would a PCAM with a large deadband allow the Company to recover its expected net power costs?

A. No. Due to the asymmetry of net power cost volatility a large deadband would only guarantee that the Company will not have a reasonable opportunity to recover its expected net power cost and earn its authorized rate of return.

Q. Issue 5.b. Provide clear definition of "nameplate capacity" if that is retained as defining eligibility for standard contracts and avoided cost rates. What is your response to this issue?

A. Nameplate capacity is actually a very straightforward definition. As used in PacifiCorp's standard contract filed in this Docket,

> "*Nameplate Capacity Rating means the maximum generating capacity, as provided by the manufacturer, in kW, of any qualifying small power or cogeneration unit supplying all or part of the Facility's Net Output. Voluntary curtailment by Seller of a generating unit cannot reduce the Nameplate Capacity Rating of that unit.*"

This is very similar to the Nameplate Capacity Rating definitions used in our other jurisdictions and applies to standard contracts and non-standard contracts. While some jurisdictions use other generator output thresholds to determine if the QF qualifies for a standard contract or not, the definition of nameplate capacity is a consistent definition across jurisdictions and also in the FERC PURPA self-certification.

Q. Is nameplate capacity the most appropriate threshold to use for QFs to qualify for published avoided costs and standard contracts?

A. Yes. The Company supports the use of the nameplate capacity for the standard contract threshold because it is much less arbitrary than a proposed level of output from the QF machine. Right upfront in the evaluation of a QF project, the nameplate capacity at the manufacturer's recommended operating conditions can be identified and verified, minimizing future disputes over qualifying for standard prices and contract.

ISSUE 8. NEGOTIATION PARAMETERS AND GUIDELINES FOR "SIMULTANEOUS SALE AND PURCHASE" QF CONTRACT.

Q. What should the negotiation parameters and guidelines be for a "simultaneous sale and purchase" QF contract?

A. This question is really only applicable to those QFs that are thermal cogeneration or combined heat & power ("CHP") projects where the generation plant itself is part of a commercial or industrial facility that uses electric energy in its operation or process even when the generation is shut down (the facility power needs are separate from the station service required by the QF to operate the generation plant). In that physical configuration, there are two power sale options available to the QF for selling their power as a QF. One, the QF can offset its electrical load that they would have purchased from the utility for their operation and sell any net output excess to the utility or, two, they can sell all net output from the generator to the utility and buy its facility electrical needs from the utility at the appropriate retail tariff rate. This is independent of whether the QF qualifies for a standard contract and prices or is a non-standard QF. In either sale options for a non-standard QF, the negotiation process, parameters and guidelines are the same for the QF (i.e., interconnection process, use of Schedule 38 if non-standard contract, timelines and milestones, etc.). However, the difference is in the structures of the QF power purchase agreement and the interconnection agreement including details on metering, billing, data access, etc. to account for a buy-all / sell-all or a net output sales structure. Those details are usually project specific and dealt with as the project moves through the development and negotiation process. The Company has negotiated and executed buy-all / sell-all QF contracts in a number of jurisdictions.

ISSUE 9. NEGOTIATING "NET OUTPUT SALES" FOR NON-STANDARD CONTRACTS.

Q. What should the negotiation parameters and guidelines be for a "net output sales" non-standard QF contract?

A. For purposes of this response I assume "net output sales" means the sale of net output from the QF in excess of any facility electrical load it would otherwise take service from the Company. As I discussed above, the Company has a strong process outlined in Schedule 38 to allow the Company and the QF to work through the negotiation process and does not see any reason to not use this process to complete a contract with a non-standard QF. OPUC Staff, along with other parties, has recommended some additional detail in Schedule 38 related to turn-around time of contract drafts that the Company finds to be reasonable and will incorporate into its Schedule 38. In either the buy-all / sell-all structure or net output sales structure, or any contract negotiations for that matter, the key to a successful transaction is the timely exchange of accurate information and agreement on milestones at the beginning of contract negotiations.

Q. Should a QF be allowed to switch back and forth between the SIMULTANEOUS SALE AND PURCHASE and the NET OUTPUT SALES option?

A. No. The QF should have the option during contract negotiations to select the option. However, once a QF has selected an option, they should not be allowed to switch back and forth between the two options during the term of the agreement. To do so would allow the QF to game the system at the expense of rate payers. For example, if customer rates are currently below QF prices, the QF would likely select the simultaneous buy /sale option. If five years later, customer prices move above QF prices, allowing the QF to switch to the net output sales option would harm rate payers.

ISSUE 11. SHOULD COMPETITIVE BIDDING BE USED TO SET PRICING FOR QUALIFYING FACILITIES GREATER THAN A CERTAIN SIZE (E.G., LARGER THAN 100 MW) IF THE UTILITY HAS RECENTLY COMPLETED AN RFP, OR A BIDDING PROCESS IS IN PROGRESS OR IMMINENT? IF SO, HOW?

Q. How does the Company propose to determine prices for QFs 100 MW or larger that are requesting a contract term of five years or longer?

A. The Company proposes that the terms, conditions and price for capacity purchases from QFs of 100 megawatts or greater with contract terms of five years or longer would be determined in an all source competitive bidding process. In order to be eligible for a capacity payment, the QF would be required to submit a proposal in that competitive bidding process and any contract for purchases of capacity from the QF would be contingent upon selection of the QF as the winning bidder in that process. PacifiCorp would not be required to accept offers for QF capacity that were made outside of the bidding process, or from QFs that were not selected through the competitive bidding process. However, PacifiCorp would be required to accept offers for QF energy at off-peak prices.

Q. Why is the Company proposing that this competitive bidding process be used to determine the terms, conditions and prices for capacity purchases from this category of large QFs?

A. The first reason is that a competitive bidding approach would provide the Commission, the customers, the Company and QF developers with the best available determination of the Company's "avoided costs" and, as a result, would best meet the customer indifference standard. Administratively determined avoided costs have become, in this and other jurisdictions, a seemingly endless debate over what resources can actually be avoided by the utility and have not always resulted in rates that meet the customer indifference standard. Under a competitive bidding approach, that debate would be replaced by a process in which avoided costs would be determined directly and simply from the bid submitted by the winning bidder. In addition, because bidding provides a mechanism for identifying potential alternative sources of supply, it would increase the chances that the Company's resource needs would be met by the more efficient and reliable supplier, thus increasing the chances of meeting the customer indifference standard.

A second reason is the failure to require those large long-term QFs to participate in the bidding process could effectively cripple that process. A disappointed RFP bidder may declare themselves to be a QF. If those QFs were allowed to proceed outside the bid process, they alone would eliminate, hypothetically, the need for the bid process. In addition, allowing large long-term QFs the option of either RFP or avoided costs prices may result in inflated RFP bid prices. Large long-term QFs would always bid above avoided costs since they always have the option to take avoided cost prices.

IS IT APPROPRIATE TO CONSIDER THE EFFECT OF DEBT IMPUTATION ISSUES RESULTING FROM NEW ACCOUNTING RULES ON AVOIDED COSTS AND IF SO, HOW?

Q. Should Debt Imputation be considered with the proposed avoided cost methodology in determining final avoided cost prices for a QF over 10MW?

A. Yes. There are accounting standards that should be considered in determining the avoided cost price for an individual QF. These applicable accounting standards are based on Emerging Issues Task Force ("EITF") 01-08, *Determining Whether an Arrangement Contains a Lease,* Financial Accounting Standard ("FAS") 13, *Accounting for Leases,* and Financial Interpretation No. 46R ("Fin 46"), *Consolidation of Variable Interest Entities.*

Q. If EITF 01-08 does not result in debt being added directly to PacifiCorp's balance sheet, do credit rating agencies consider contractual resources as debt-like?

A. Yes. Major credit rating agencies and other members of the financial community view contractual resources as being debt-like and, as a result, will impute or infer debt on the purchaser's financial statements. These adjustments will then be used in ratio calculations and for ratings purposes. As in the case of debt being added directly to PacifiCorp's balance sheet, equity must be infused in order to offset the effects of this inferred debt. Likewise, this equity has a cost associated with it. PacifiCorp needs to take this cost into account when considering QF agreements. Company witnesses Mr. Stuver and Mr. Shah will discuss the accounting issues and the impact to the Company in greater detail in their testimony.

Q. If imputed debt occurs, how should it be applied to the QFs prices?

A. Since these debt calculations must be done on an agreement by agreement basis, it is appropriate for the implicit debt cost to be addressed separately from the avoided cost pricing process and included in the power purchase agreement as a monthly line-item adjustment to the QF payment rather than embedded in the proxy stage of the avoided cost pricing process. Currently, all QF power purchase agreements, regardless of size, go through a screening process to determine the accounting standards and cost associated with inferred and or direct debt.

Q. Does this conclude your testimony?

A. Yes it does.

Case UM-1129
Exhibit PPL/700
Witness: Douglas K. Stuver

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Douglas K. Stuver

Accounting Standards

February 2006

Q. Please state your name, business address and present position with PacifiCorp.

A. My name is Douglas K. Stuver. My business address is 825 N.E. Multnomah, Suite 600, Portland, Oregon. I am a Managing Director of Finance in PacifiCorp's Commercial and Trading group.

Qualifications

Q. Please briefly describe your education and business experience.

A. I graduated from the University of Pittsburgh at Johnstown in 1985 with a Bachelor of Arts degree in Business Administration. I joined Ernst & Young as an auditor upon graduation, obtained my Certified Public Accountant license in 1988, and worked for Ernst & Young for eight years, leaving as a senior manager. I have worked for three energy companies – Enserch Energy Services (Vice President and Controller), CNG Energy Services (Director, Trading and Operations Support), and Duke Energy Corp. (Controller and Vice President, Corporate Risk Management) – prior to joining PacifiCorp.

Q. In your position, have you been involved in an analysis of the impact of new accounting standards on PacifiCorp?

A. Yes. In conjunction with our independent external auditors, I have reviewed the impact on PacifiCorp of Emerging Issues Taskforce ("EITF") 01-8, entitled "Determining Whether an Arrangement Contains a Lease" and Financial Interpretation No. 46R ("FIN 46"), "Consolidation of Variable Interest Entities."

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the impact of new accounting standards on

PacifiCorp's financial statements as they relate to power purchase agreements with qualifying facilities (QFs) as a result of EITF 01-8 and FIN 46.

Q. **Q. Would you please explain the financial statement impacts of the EITF 01-8 and FIN 46 in relation to long-term power purchase agreements with QFs?**

A. EITF 01-08 addresses the circumstances under which lease accounting shall be applied to contractual arrangements and FIN 46 addresses an issue commonly known as "off balance sheet financing." The intent of these two independently applied standards is to provide better transparency to potential investors, shareholders and bondholders regarding the fixed obligations of an entity for financial reporting purposes. Under EITF 01-8, PacifiCorp is required to review contracts with QFs executed or modified after July 1, 2003 to determine whether or not they contain a lease. If a lease exists, it must be analyzed under Financial Accounting Standard 13 ("FAS 13"), Accounting for Leases to determine whether the contract will be treated as a capital versus operating lease. If, after reviewing the contract under the FAS 13 rules, it is determined to be a capital lease, then PacifiCorp would be required to record the contract as debt on its balance sheet with a corresponding capital lease asset on the balance sheet. When applied to QFs, FIN 46 could require the assets and liabilities of the QF to be consolidated on PacifiCorp's books if it is determined that PacifiCorp is the primary beneficiary. The determination of the primary beneficiary is a complex process that takes many factors into account. Exhibit PPL/701 is a simplified illustration of how to apply EITF 01-8 and FIN 46 to QF purchase agreements.

Q. What are the EITF 01-8 criteria?

A. When fulfillment of a contract with a QF is dependent upon a specific plant and the contract allows the purchaser the ability or right to operate the plant, gives the purchaser control over physical access to the plant, or if it is unlikely that other parties will take more than a minor amount of output from the plant (10%), the lease criteria of FAS 13 must be applied unless the price the purchaser pays is a single fixed price per unit of output or at a market price per unit of output.

Q. What type of information would need to be provided by the QF for your analysis under EITF 01-8?

A. The following items are important factors for determining whether other parties will take more than a minor amount of the output of a facility. It should be noted that production tax credits and allowances such as green tags are not included in the analysis.

i. Total expected output.
ii. Amount of expected output others will purchase.
iii. Evidence of their ability to sell to others.
iv. Expected revenue from steam sales (if applicable).
v. Support for their ability to sell steam (if applicable).

Q. What are the FAS 13 criteria?

A. If a contract meets any one of the following conditions, it is considered a capital lease and a debt obligation is recorded on the purchaser's books:

i. Ownership transfer at the end of term;
ii. Bargain purchase option;

iii. Term greater than 75 percent of the estimated *economic* plant life; or

iv. Net present value (NPV) of minimum lease payments less executory costs, discounted at lessee's incremental borrowing rate is greater than or equal to 90 percent of asset fair value;

If a contract does not meet any of the above criteria then the contract is considered an operating lease and a debt obligation is not recorded on the purchaser's books. The guidance under FAS 13 is mirrored by the FERC equivalent in 18 CFR, Pt. 101, General Instructions, paragraph 19, *Criteria for classifying leases*.

Q. What type of information would need to be provided by the QF for your analysis under FAS 13?

A. The following items are important factors for determining whether a contract qualifies as a capital lease under FAS 13.

i. Project cost to build (all encompassing).

ii. Contract term.

iii. Executory & non-executory cost breakdown where executory costs are costs such as insurance, maintenance, and taxes incurred for the property including profits. Any cost that is not directly related to operating the plant should be considered executory.

iv. Engineering study showing expected life of asset.

Q. What are the FIN 46 criteria?

A. FIN 46 requires a company to consolidate an entity in which it holds less than a majority voting interest but has a "controlling financial interest" through its contractual arrangements with that entity. Under FIN 46, the entity may be subject to consolidation when any of the following exist:

a). The entity is thinly capitalized,

b). Residual equity holders do not control the entity,

c). Equity holders do not participate fully in an entity's residual economics, or

d). The entity was established with non-substantive voting interests.

If the company is exposed to the majority of the risks and rewards associated with an entity having any of the above characteristics, the company is considered to have a controlling financial interest in that entity and must consolidate that entity.

Q. How will the Company account for a debt-related cost adjustment to the avoided cost payment?

A. For operating leases, PacifiCorp will record the amount of the QF payment, which has been reduced for the debt-related cost adjustment, to Purchased Power Account 555. This account is a component of revenue requirements, thereby flowing the benefits of the debt-related cost adjustment directly through to ratepayers.

For capital leases, PacifiCorp will include the reduction in QF payments due to the debt-related cost adjustment as a reduction in the amount of future minimum lease payments. This, in turn, reduces the depreciation and interest expense associated with the contract. These costs are recorded to Purchased Power Account 555. This account is a component of revenue requirements, thereby flowing the benefits of the debt-related cost adjustment directly through to ratepayers.

Q. Does this conclude your testimony?

A. Yes.

701 Stuver Exhibit

Case UM-1129
Exhibit PPL/701
Witness: Douglas K. Stuver

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

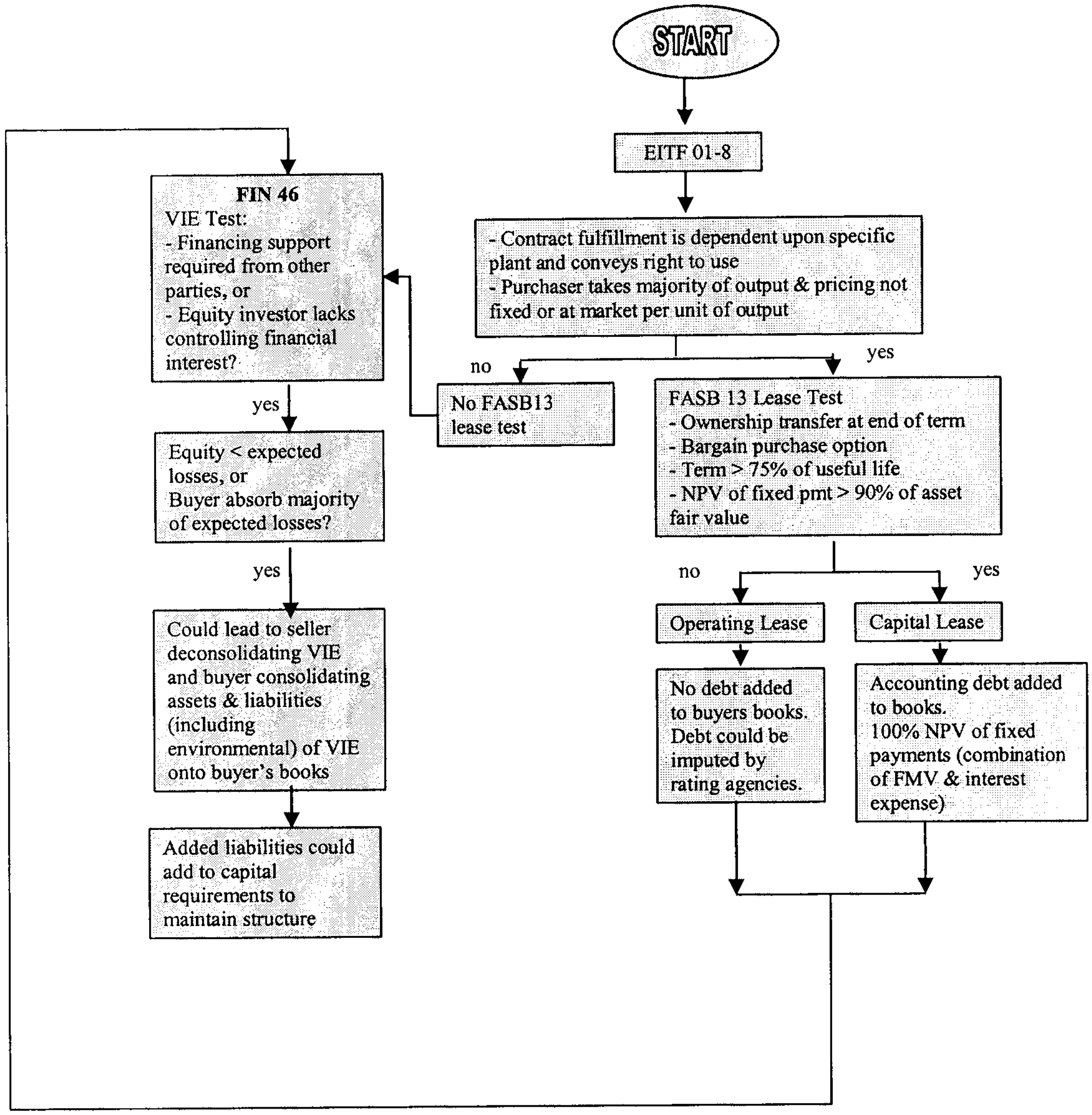
PACIFICORP

Exhibit Accompanying Direct Testimony of Douglas K. Stuver

How PPA Impacts Balance Sheet

February 2006

How PPA Impacts Balance Sheet



Case UM-1129
PPL Exhibit 800
Witness: Mahendra B. Shah

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Mahendra B. Shah

Debt Imputation Cost of QF Contracts

February 2006

Q. Please state your name, business address and present position with PacifiCorp.

A. My name is Mahendra B. Shah. My business address is 825 N.E. Multnomah, Suite 1900, Portland, Oregon 97232. I am the Director of Treasury at PacifiCorp.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a Ph.D. degree in Finance from University of Houston in 1979. In 1984, I received the Chartered Financial Analyst designation. Since November 2004, I have been employed at PacifiCorp. Previously, I was employed for 24 years at Portland General Electric Company. My business experience has included financing of electric utility operations and non-utility activities, investment management, investor relations and management of credit exposure. I have testified before the Oregon Public Utility Commission on matters related to financing applications, project financing and leveraged lease transactions and the Utah Public Service Commission on the effect of purchased power obligations on the credit matrix of PacifiCorp.

Q. Please describe your present duties.

A. I am responsible for the daily activity related to the Company's pension and other investment management and also support the utility financing activities.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. As Mr. Stuver explains in his direct testimony, Emerging Issues Taskforce 01-08 ("EITF 01-08") and Financial Accounting Standards Board (FASB) No. 13

require PacifiCorp to recognize its obligations under certain Qualifying Facility ("QF") contracts as capital lease obligations. Because these QF capital lease obligations are considered to be debt and would be treated like any other debt obligation of the Company, they have impacts on both the Company's financial commitments and credit quality. Further, even if a QF contract is not treated as a capital lease obligation, it may have similar debt impacts pursuant to Financial Interpretation No. 46R ("FIN 46R") or it would have similar debt-like impacts on the Company under guidelines established by rating agencies.

My testimony will provide an overview of the way in which PacifiCorp finances its operations and discuss the reasons why the recognition of additional debt associated with purchases from QF contracts will impose additional costs on the Company and its customers. I will also explain how to calculate the incremental cost associated with the additional debt and the Company's proposal for how to recover that additional cost.

Financing Overview

Q. How does PacifiCorp finance its electric utility operations?

A. PacifiCorp requires large amounts of capital to construct and maintain its electrical infrastructure. In order to raise that capital, PacifiCorp relies on a mix of first mortgage bonds, other secured debt, tax exempt debt, unsecured debt, preferred stock and common equity.

Much of the Company's long-term financing is done using first mortgage bonds and medium term notes issued under the PacifiCorp Mortgage Indenture dated January 9, 1989. As of December 31, 2005, PacifiCorp had $ 3,271 million of taxable debt, plus $400 million of tax-exempt pollution control debt outstanding, issued under the PacifiCorp indenture. In addition, the Company regularly borrows tens of millions of dollars to meet more short term financing requirements.

PacifiCorp has a large capital program that is expected to further increase in order to serve the growing needs of its customers. In order to have access to the capital markets and attract the capital that will be necessary to fund this expansion, PacifiCorp must maintain its credit quality and comply with its financing agreements and other commitments.

Regulatory Commitments

Q. Does PacifiCorp have commitments that limit the amount of debt in its capital structure?

A. Yes. For example, PacifiCorp and ScottishPower, have made commitments to state utility commissions and the U.S. Securities and Exchange Commission ("SEC") concerning PacifiCorp's minimum level of common equity as a percentage of capitalization. These commitments must be met for PacifiCorp to continue to utilize financing authority from the SEC. More recently, MidAmerican Electric Holdings Company, ("MEHC"), has made similar commitments to state utility commissions. To the extent that obligations under QF contracts are treated as debt under accounting standards, it could impact PacifiCorp's ability to meet those commitments. This may lead to the likelihood of seeking new common equity or delaying or reducing capital spending programs.

Additional Costs Imposed by QF Contracts

Q. Could the direct recognition of QF contract obligations as debt on the Company's balance sheet, impose additional costs associated with credit quality?

A. Yes. It is important to have a balanced capital structure and additional debt through QF contracts will lead to a need for additional equity to avoid adverse impacts on credit quality. The debt related to QF contracts reduces the amount of debt the Company might otherwise issue if the Company is to maintain a particular debt/equity ratio. There is a cost when the Company's ability to issue debt is reduced. Specifically, because equity is more expensive than debt, the increase in equity required to offset (balance) the QF contract-related debt and allow PacifiCorp to maintain credit quality and compliance with its financing agreements and other commitments would impose additional costs on PacifiCorp and its customers.

Q. Would all QF contracts result in debt being added directly to PacifiCorp's balance sheet?

A. No. As Mr. Stuver discussed, the only QF agreements that would result in both debt being added directly to PacifiCorp's balance sheet, and interest expense being included on the income statement, are those agreements where the application of EITF 01-08 or FIN 46R accounting rules would dictate such an application. However, even if debt is not added directly to the Company's balance sheet due to accounting treatment, in certain situations, credit rating agencies infer debt associated with power purchase agreements.

Q. If a QF contract results in debt being added to the Company's balance sheet, yet it does not require the utility to immediately issue equity to balance the capital structure, is there an additional cost?

A. Yes. All QF contracts, whether large or small, that result in debt equivalent recognition on the financial statements or by the credit rating agencies, diminish the credit capacity of the utility. There is a cost related to the diminished credit capacity.

Q. Can that cost be calculated or observed?

A. Yes. The additional cost associated with a QF contract is equal to the pro-rata share of the cost of diminished credit capacity. The additional cost is the difference between the cost of equity and the blended cost of capital required to balance the capital structure, times the amount of equity that must be infused as a result of the recognized debt due to the QF contract. The size of the additional cost is large or small depending upon the amount of debt that arises as a result of the contract. Whether the absolute magnitude of the impact is large or small, the cost should be recognized, calculated, and borne by the party that imposes the cost. In simple terms, the cost is the difference between the pre-tax cost of equity and the pre-tax weighted average cost of capital times the amount of equity needed to rebalance the capital structure. This methodology is discussed in Exhibit PPL/801.

Q. Even if an obligation from a QF contract is not recognized as debt on PacifiCorp's books, does it adversely impact PacifiCorp's credit quality and result in an additional cost, such as that described previously?

A. Yes. Rating agencies view long-term purchased-power agreements such as QF contracts, as debt-like in nature. For rating purposes, the rating agencies do not simply assess a company's revenues, but also all of the expenses a company must cover with its revenues. Cash flow is one of the more important items in credit analysis. Cash flow is measured as the cash available from operations plus any non-cash expenses and is frequently compared against various debt and fixed payment obligation measures, including an amount of inferred debt associated with fixed payment obligations associated with QF contract.

Even when the accounting standards do not classify a contract as a capital lease, in certain situations, rating agencies such as Standard & Poor's ("S&P") will calculate an amount to impute as a debt equivalent related to purchased-power agreements. This amount of debt equivalent is added to a utility's reported debt to calculate adjusted debt and evaluate cash flow to debt metrics. Similarly, rating agencies impute an associated interest expense related to the debt equivalent, which is then added to reported interest expense to calculate adjusted interest coverage ratios. Exhibit PPL/802, details Standard & Poor's views on this matter.

Q. What debt level (accounting-related or rating agency methodology) should be utilized in determining these additional costs?

A. The debt that should be utilized for determining additional debt-related costs associated with QF contracts should be the higher of: (1) the debt directly added to the Company's balance sheet as a result of applying applicable accounting rules or, (2) the debt determined by the most transparent rating agency methodology.

Q. Which rating agency currently has the most transparent methodology?

A. At the present time, it is S&P's.

Q. How does S&P translate the costs associated with PPAs into an amount of debt it will impute or infer on the purchaser's financial statements?

A. Standard & Poor's calculates the amount of debt by multiplying a risk factor by the present value of fixed payments, discounted at 10 percent. In its May 05, 2005 research report, S&P added about $570 million to PacifiCorp's balance sheet debt to reflect the indebtedness of which $520 million was related to the Company's long-term power purchase commitments. (See Exhibit PPL/803).

In its September 20, 2005 research report, Standard & Poor's discussed PacifiCorp's credit ratios adjusted for its purchased power obligations (Exhibit PPL/804).

Q. What risk factor should be applied under the Standard & Poor's methodology to calculate the amount of debt equivalent for QF obligations?

A. Standard & Poor's has stated that a 50 percent risk factor is appropriate for long-term commitments (e.g. terms greater than three years) as a generic guideline for utilities with purchased power agreements that do not have power cost adjustment mechanisms. Standard & Poor's presently uses a 50 percent risk factor in their credit evaluation of PacifiCorp. Standard & Poor's use of a relatively high risk factor for PacifiCorp is consistent with the risk assessment of PacifiCorp's power/commodity cost recovery by Fitch (See Exhibit PPL/805). PacifiCorp will track changes in the rating agency perspective on the debt equivalence of power purchase commitments as and when the agencies update their methodology and the risk factor ascribed to PacifiCorp.

Q. What does PacifiCorp propose to recover the debt imputation costs from QF contracts and help maintain its credit quality?

A. Whether a QF contract results in debt being added directly to the Company's balance sheet because of the new accounting standards or being imputed onto the Company's balance sheet by rating agencies, there is a real and calculable additional cost to the Company. If the cost is not borne by the QF, the cost will effectively be shifted to customers and result in compensation to the QF that exceeds the avoided cost. In that case, the PURPA ratepayer indifference standard will be violated. The Company believes that since the QF imposes the need to rebalance the capital structure, it should bear the related cost. In order to maintain ratepayer indifference, PacifiCorp proposes to calculate the additional costs associated with the direct or imputed debt on an agreement-by-agreement basis and then make a debt-related adjustment to the QF payment.

Q. How can the cost of diminished credit be equitably borne by the QF?

A. QF contracts have two cost impacts, cash payments and the cost of rebalancing the capital structure to offset the diminished credit related the debt or debt equivalence of the contract. Cash payment to the QF would equal the avoided cost without regard to the imputed debt issue, less the change in revenue requirement due to rebalancing the capital structure required by the contract.

For illustration purposes, if the avoided cost determined by the Public Utility Commission is \$46/MWh and the average cost per MWh of rebalancing the capital structure is \$2/MWh, then the cash payment to the QF would equal \$44/MWh, which would be the net avoided cost. The cash payment to the QF is reduced by an amount equal to the revenue requirement impact of rebalancing the capital structure. This method results in a combined cost of power to customers that equals the avoided cost. Failure to adjust the avoided cost payment for costs the QF contract imposes on utility customers will result in a contract cost that exceeds the avoided cost.

Q. How does the Company calculate the additional costs imposed on the Company related to direct or imputed debt?

A. As the cost equals the incremental equity required to rebalance the capital structure times the difference between the pre-tax cost of equity and the pre-tax weighted average cost of capital, the Company determines the amount of equity needed to offset the debt or debt equivalent (imputed debt) in order to maintain the capital structure at the same level that was in place prior to entering into the contract. An example of a theoretical calculation is provided in Exhibit PPL/806. In the example, the beginning equity ratio is 48 percent, shown on line 2. In this example, \$100 million of debt is added to the Company's balance sheet as a result of a capital lease, reducing the equity ratio to 43.6 percent, shown on line 6. \$92.3 million of equity is then issued to offset the direct debt. As can be seen on line 11, the equity ratio returns to the original 48 percent ratio from this equity infusion. The revenue requirement of the incremental equity is calculated in lines

13 through 17, which shows an annual cost of $5.149 million. Simply stated, the revenue requirement cost equals the cost of equity minus the weighted average cost of capital times the amount of equity issued to rebalance the capital structure. This cost or revenue requirement would then be converted to a basis for adjusting compensation to the QF. A similar method would be used to calculate the costs associated with imputed debt; however, as noted above, the higher of the two calculations should be used for determining additional debt-related costs.

Q. Does this conclude your testimony?

A. Yes.

801 Shah Exhibit

Case UM-1129
Exhibit PPL/801
Witness: Mahendra B. Shah

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mahendra B. Shah

Debt Determination and Cost for Contracted Power Supply

February 2006

Debt Determination and Cost for Contracted Power Supply

General:
A PPA or other power supply contract can result in **direct debt** (via lease accounting pursuant to EITF 01-08 and FAS No. 13) or **inferred debt** (via rating agency debt inference). Returning to the pre-contract debt/equity ratio requires more equity. Equity has a cost associated with it and, as a result, the following calculation should be performed for any PPA > 3-years in term to quantify this cost.

Definitions:

- PPA - Power Purchase Agreement
- FMV – Fair Market Value. FMV is the current market value of an asset. Since this is rarely known, the FMV should be assumed to be the cost the buyer expects it would incur to construct a comparison asset.
- NPV – Net Present Value of a stream of cash flows at a given discount rate.
- S&P Debt – The debt that rating agencies (S&P in this case) are anticipated to infer due to an applicable PPA or contract. S&P Debt is determined by taking the NPV (at a 10% discount rate) of the capacity component of the payments and multiplying it by a risk factor. The generic risk factor that S&P uses (for utilities with PPAs included as an operating expense in base tariffs) is 50%[1]

  [**note:** The risk factor can be lower, 30% for example, for utilities that have effective power cost adjustment mechanisms (PCAMs)].
- WACC – Weighted Average Cost of Capital.
- IncEquity1 - incremental equity due to **direct debt** from lease accounting or consolidation under FIN-46, if applicable.
- IncEquity2 – incremental equity due to rating agency **inferred debt**, if applicable.

Cost Calculation:
Assuming the minimum debt/equity split allowed by regulators (which translates to a maximum WACC allowed) is 50/50, a cost of debt of 6.91% and an allowed return on equity of 17.2%[2], the maximum WACC allowed would be 12.055% (0.5*.0691+0.5*.172). [**note:** The actual debt/equity split, as well as actual cost of debt, common equity, and preferred equity should be used for analysis purposes]

Annual Debt-Related Cost = (17.2% - 12.055%) (higher of IncEquity1 or IncEquity2) where;

IncEquity1 = MAX [Equity Infusion Required, 0], where;

Equity Infusion Required = MIN [(NPV Non-Executory Payments[3] ÷ Pre-PPA Debt-to-Asset Ratio) X (Pre-PPA Equity-to-Asset Ratio), FMV ÷ (Pre-PPA Debt-to-Asset Ratio) – FMV]

IncEquity2 = MAX [(S&P Debt ÷ (Pre-PPA Debt-to-Asset Ratio)) X (Pre-PPA Equity-to-Asset Ratio)), 0]

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[1] A risk factor as low as 30% could be used for utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs. In certain cases, S&P may consider a lower risk factor of 10-20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. A risk factor for PURPA qualifying facilities may be assumed to be between 10-30% depending on past recovery precedent. Reference October 2003 S&P article.

[2] Since preferred & common equity holders demand a weighted 10.7% after taxes in this case, the before tax rate needs to be grossed up to take into account the marginal tax rate of 37.95%. The before tax cost of equity should therefore be 17.2% (.107 ÷ (1-.3795)).

[3] Discount rate equal to buyer's incremental cost of debt for a like term and amount.

802 Shah Exhibit

Case UM-1129
Exhibit PPL/802
Witness: Mahendra B. Shah

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mahendra B. Shah

Standard & Poor's Utilities and Perspectives
May 12, 2003

February 2006

PPL/802
Shah/1

May 12, 2003
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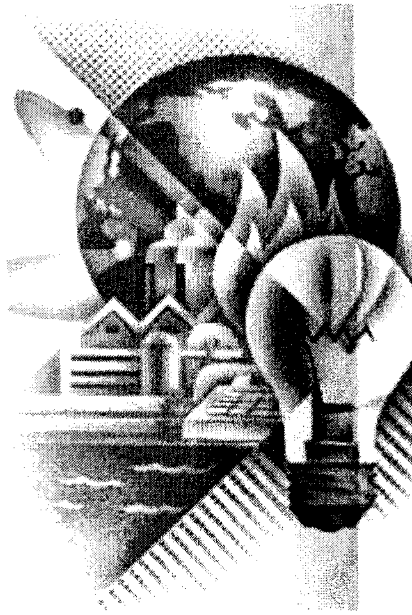

Standard & Poor's
UTILITIES & PERSPECTIVES
GLOBAL UTILITIES RATING SERVICE

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"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery—and thus release from the payment obligation—is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity

Back to Table of Contents
Next Page

component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as

Table 1

ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	—	—	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2

ABC Utility Co. Adjustment to Pretax Interest Coverage

		Original pretax interest coverage		Adjusted pretax interest coverage	
Net income	120				
Income taxes	65	300		(300+33)	
Interest expense	115	115	= 2.6x	(115+33)	= 2.3x
Pretax available	300				

Back to
Table of Contents
Next Page

a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build—i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%—10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (48 plus 11). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means. ■

Jeffrey Wolinsky, CFA
New York (1) 212 438-2117
Dimitri Nikas
New York (1) 212-438-7807
Anthony Flintoff
London (44) 20-7826-3874
Laurence Conheady
Melbourne (61) 3-9631-2036

803 Shah Exhibit

Case UM-1129
Exhibit PPL/803
Witness: Mahendra B. Shah

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Mahendra B. Shah

Standard & Poor's Research Report
May 5, 2005

February 2006

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Research:

Summary: PacifiCorp

Publication date: 05-May-2005
Primary Credit Analyst(s): Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Credit Rating: A-/Stable/A-2

Rationale

The ratings on PacifiCorp reflect an average business profile, a diversified service territory, a reasonably balanced generation portfolio, and recent favorable regulatory treatment in the six western states it serves. PacifiCorp comprises about 45% of ultimate parent Scottish Power's operating profit. The consolidated Scottish Power financial profile has remained adequate for the rating, despite the fact that the utility's financial profile was until recently strained by significant amounts of deferred power costs.

Since 2002, PacifiCorp has been recovering the sizable power costs it incurred during the western energy crisis in 2000 and 2001. Collection in retail rates of about $303 million of the $537 million that PacifiCorp deferred began in fiscal 2003. But by the end of Dec. 31, 2004, the utility had collected in retail rates all but $26 million in deferred costs, and full recovery is expected to be completed over the next six months.

PacifiCorp faces near-term challenges to its financial performance that are expected to be compensated by the continued strength of Scottish Power consolidated operations. Scottish Power announced last November that collectively PacifiCorp and PacifiCorp Group Holdings Co. (PGHC) would likely fall short of a fiscal 2005 target of $1 billion in earnings before interest and taxes (EBIT, reported on a U.K. GAAP basis), due largely to plant performance and weaker electricity sales at PacifiCorp. (This target excludes the operations of PPM Energy Inc., which is also a subsidiary of PacifiCorp Holdings Inc. [PHI].) The company plans to publish full-year earnings for fiscal 2005 in late May.

Fiscals 2006 and 2007 are forecast to also remain flat on a U.K. GAAP reporting basis. In March, Scottish Power advised that PacifiCorp's first six months of fiscal 2006 performance could be adversely affected by low hydro availability in the Pacific Northwest. About 10% of PacifiCorp's installed capacity is hydro generation, typically supplying between 4% to 8% of the utility's annual generation requirements. Management has estimated that replacement power costs could total about $60 million during calendar 2005. To allow deferred recovery of these expected costs, PacifiCorp recently filed with the Oregon state commission for permission to establish a deferred power account and is expected to do so in Washington.

The absence of a power cost adjustment mechanism in any of the states PacifiCorp serves is an ongoing credit concern because of the uncertainty over the timing and ultimate recovery of potential, new deferred power costs. However, the utility is pursuing adjusters with regulators, and regulatory relationships are stable. In February, the Utah Public Service Commission approved a $51 million rate case settlement, providing a 4% increase that began March 1 and represents a 10.5% return on equity (ROE). In February 2005, the state enacted Senate Bill (SB) 26, which establishes a resource procurement process for PacifiCorp that should substantially increase the utility's prospects for cost recovery. The utility has a pending rate case in Oregon, which is expected to be decided sometime in 2005. Also, four of the six states served by PacifiCorp have approved an agreement for allocating common costs, referred to as the multi-state process, which should streamline recovery of these costs.

Another significant challenge is to effectively manage a $3 billion capital expenditure program. The company is currently building two new gas-fired combined cycle plants. About 280 MW of Currant Creek is expected on line this summer, with 525 MW added by 2006. Lakeside, a 534-MW plant, is expected to be commercial by summer of 2007. Both projects are on time and on budget.

PacifiCorp is headquartered in Portland and serves about 1.6 million retail customers in a 136,000-square-mile service territory in portions of Utah, Oregon, Wyoming, Washington, Idaho, and California. Business is conducted under the legal names of Pacific Power and Utah Power & Light. PacifiCorp is a wholly owned subsidiary of PHI, which in turn is a non-operating, direct, wholly owned subsidiary of U.K. holding company Scottish Power plc.

Short-term ratings factors.

The short-term rating on Scottish Power, Scottish Power U.K. PLC, and PacifiCorp is 'A-2'. In the short term, the companies are expected to have ample internal liquidity, owing to a steady, predictable net cash flow stream produced by regulated businesses, minimal debt maturities over the next few years, good credit facility capacity, and more stable pricing in the western U.S. power markets. Scottish Power's discretionary cash flow after dividends and capital expenditure is expected to be negative in 2004, but its sizable unrestricted cash balance should finance any shortfall. Cash balances, amounting to £424 million at Dec. 31, 2004, are held in a variety of quickly accessible funds.

Scottish Power has sufficient liquidity to cover its outstanding debt obligations and good financial flexibility to access funds in the event of unexpected cash flow interruptions. Full capacity exists under a $1 billion revolving credit facility, split between a $625 million facility and a $375 million facility, both due in 2008. Scottish Power U.K. maintains a $2 billion Euro-commercial paper program, which is undrawn. Liquidity was further enhanced by the issuance of $1.5 billion of long-term debt during March 2005.

PacifiCorp provides for its own liquidity needs. PacifiCorp's cash and cash equivalent position was $25 million as of Dec. 31, 2004, down from $59 million as of March 31, 2004. Liquidity is enhanced by the utility's $800 million commercial paper program. As of Dec. 31, 2004, the company had drawn $285 million in commercial paper. An $800 million revolver executed in May 2004 backstops the commercial paper program. There were no borrowings under the facility as of Dec. 31, 2004. Regulatory authorities limit PacifiCorp from issuing more than $1.5 billion in short-term debt.

PacifiCorp's discretionary cash flow after dividends and capital expenditure is expected to be negative in fiscal 2005. PacifiCorp's long-term debt outstanding was $3.7 billion as of Dec. 31, 2004, excluding current maturities. Future maturities of $289 million in fiscal 2006 are in line with historic obligations. Affiliate transaction rules restrict PacifiCorp from lending to any of PHI's subsidiaries or U.K. affiliates.

Outlook

The stable outlook reflects consolidated Scottish Power's financial ratios that are adequate for the rating and the steady operational and financial performance at the company's regulated subsidiaries. To maintain the rating, Standard & Poor's expects Scottish Power to produce cash flow coverage ratios commensurate with the 'A-' level--adjusted FFO interest coverage of about 4.0x and adjusted FFO to debt of 20%--and to manage its U.K. generation and supply and U.S. unregulated energy management business conservatively. An improvement in the ratings is less likely, given the sizable capital expenditures for both the U.K. and U.S. operations, and management's expectations that PacifiCorp's financial performance over the next few years will remain flat.

Accounting

PacifiCorp is one of four subsidiaries of PacifiCorp Holdings Inc. (PHI), which is an indirect subsidiary of Scottish Power plc. Other companies under PHI are unregulated and consist of PPM Energy Inc. (PPM); Pacific Klamath Energy Inc. (PKE); and PacifiCorp Group Holdings Co. (PGHC), a holding company for non-regulated companies, including PacifiCorp Financial Services Inc. (PFS).

PacifiCorp's financial statements are prepared under U.S. GAAP standards and are audited by PriceWaterhouseCoopers LLC, which provided an unqualified opinion for fiscal 2004, which ended March 31, 2004. PacifiCorp's financial statements are also reported as part of its parent, Scottish Power, whose audits are prepared under U.K. GAAP by PWC. PacifiCorp is the only subsidiary under PHI that has issued public debt in the U.S., and as such is the only PHI company that is required to file before the Securities and Exchange Commission (SEC). Scottish Power's financial segment reporting combines the results of operations for both PacifiCorp and PGHC, whereas U.S. filings reflect the stand-alone results of the utility.

Comparison of PacifiCorp's financial results as filed with the SEC to those reported by Scottish Power's requires making a number of adjustments to reconcile differences between U.S. and U.K. GAAP accounting as well as the inclusion of PGHC. The largest difference is attributable to the differing treatment of PacifiCorp's recovery of sizable power costs incurred several years ago. Under U.K. GAAP, PacifiCorp's replacement power obligations were expensed in full when incurred on Scottish Power's income statement. But under U.S. GAAP FAS 71 allowed the utility to create a regulatory asset on the utility's balance sheet. As PacifiCorp has collected these deferred costs in rates, its income statement has reflected the amortization of deferred power costs as an expense under U.S. GAAP, providing a smoothing effect for PacifiCorp net income. In contrast, as the recovery of deferred costs flows directly into revenues, with no offsetting amortization expense, U.K. GAAP earnings have been boosted over the period of recovery. In fiscal 2004, for example, U.S. GAAP EBIT for PacifiCorp and PGHC was $685 million, but on a U.K. GAAP basis, EBIT was $945 million. Power cost deferrals accounted for $110 million of this difference. With the pending completion of recovery in fiscal 2006, the wedge between U.K. and U.S. GAAP will narrow, but other recurring adjustments to depreciation and other accounts will remain. And, beginning in April 2006, Scottish Power will adopt International Accounting Standards. PGHC is involved in the receipt of revenues under synthetic fuels contract and the leasing of commercial aircraft.

PacifiCorp has sizable power purchase obligations, and as a result, Standard & Poor's Ratings Services has added about $570 million to the utility's balance sheet that predominantly reflects long-term power purchase agreements (PPAs) and about $46 million in operating leases. Standard & Poor's uses a 50% risk factor in calculating off-balance sheet debt associated with these PPAs. The passage of SB 26 implies that a lower risk factor will be utilized for future Utah PPAs that fall under the protection of the new legislation.

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Case UM-1129
Exhibit PPL/804
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BEFORE THE PUBLIC UTILITY COMMISSION

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Exhibit Accompanying Direct Testimony of Mahendra B. Shah

Standard & Poor's Research Report
September 20, 2005

February 2006

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Research:
Research Update: PacifiCorp's First Mortgage Bonds Assigned 'A-' Preliminary Rating

Publication date: 20-Sep-2005
Primary Credit Analyst(s): Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Credit Rating: A-/Watch Neg/A-2

Rationale

On Sept. 20, 2005, Standard & Poor's Ratings Services assigned its 'A-' preliminary rating to PacifiCorp's first mortgage bonds and its 'BBB+' rating to senior unsecured obligations under a mixed shelf registration filed by the company on Sept. 6, 2005. The filing permits the issuance of up to $700 million in senior secured and unsecured debt.

The 'A-' corporate credit rating on PacifiCorp reflects the consolidated credit quality of the utility's parent, ScottishPower PLC (A-/Stable/A-2). Ratings of PacifiCorp remain on CreditWatch with negative implications following the May 2005 announcement that the Oregon-based utility is to be sold to MidAmerican Energy Holdings Inc. (MEHC; BBB-/Watch Pos/--) for $9.4 billion, including $5.1 billion in cash, and the assumption of $4.3 billion in net debt and preferred stock. The purchase will be effectuated by the purchase of the outstanding shares of common stock of the utility, which is currently held by PacifiCorp Holdings Inc. (PHI; A-/CW Developing). PHI is the indirect holding company for ScottishPower's U.S. interests, which, in addition to PacifiCorp, include PPM Energy Inc., Pacific Klamath Energy, and PacifiCorp Group Holdings (PGHC).

PacifiCorp is a vertically integrated electric utility that serves about 1.6 million customers in portions of Utah, Oregon, Wyoming, Washington, Idaho, and California. Utah and Oregon accounted for about 70% of retail electric revenues in fiscal 2005 (ended March 31). The company is regulated by the state utility commissions in each of these states. PacifiCorp's satisfactory business profile score of '5' (on a 10-point scale, where '1' is the strongest) reflects a predominately coal-fired generation fleet that provided about 80% of energy requirements in fiscal 2005, low retail electric rates relative to other investor-owned utilities in the western U.S., and a regulatory profile that has been improving, although the utility lacks a fuel and purchased power adjustment mechanism in any of the jurisdictions it serves. However, persistently poor financial performance caused by a variety of factors, including the California power crisis, historic disallowances for purchased power, regulatory lag, issues with plant performance, and large capital expenditures prompted ScottishPower to sell PacifiCorp, which it acquired in 1999.

The CreditWatch with negative implications status reflects that the current 'A-' corporate credit rating on PacifiCorp is based on ScottishPower's consolidated credit profile, whose solid financial performance has compensated for its weaker U.S. utility, which constitutes about 45% of cash flows. On a stand-alone basis, PacifiCorp's debt leverage and cash coverage ratios are solidly in the 'BBB' category. For the first quarter ending June 30, 2005, funds from operations (FFO) to interest and FFO to total adjusted debt was 3.3x and 16.3%, respectively. Standalone debt to total capitalization was 58.9%, adjusted for PacifiCorp's purchased power obligations. Thus, how the acquisition is structured will materially affect PacifiCorp's ratings if the transaction closes. In regulatory filings, MEHC has stated its intent to create a limited liability company, PPW Holdings LLC, which will be a direct subsidiary of MEHC. MEHC has indicated that no new debt will be issued at PPW, and that existing utility debt of $3.9 billion and $86.3 million in preferred stock (both as of June 30) will reside at PacifiCorp.

PacifiCorp's cash flows have been volatile for an investor-owned utility, but have stabilized somewhat in recent years, with FFO reaching $805 million in fiscal 2005, in line with fiscal 2004. But due to steady increases in debt driven largely by rising capital expenditures, financial metrics deteriorated slightly in fiscal 2005 relative to fiscal 2004, but are significantly improved over performance from fiscals 2001 through 2003. In the first quarter of fiscal 2006, PacifiCorp issued $300 million in first mortgage bonds to pay down the utility's commercial paper balances. This increased leverage was partially offset by an equity contribution of $125 million from PHI made on June 30, 2005, as discussed further in the short-term ratings section below.

Capital expenditures are a substantial challenge for the utility, and largely account for the utility's negative free operating cash flow position of $141 million at year-end fiscal 2005, when capital expenditures totaled $852 million. The company estimates that for the next five years, more than $1 billion will be needed each year for new plant construction, emissions and environmental compliance, and investment in infrastructure, particularly in Utah, where retail customer growth is forecast to be about 3% per annum.

The transaction does face some regulatory risk; the Federal Energy Regulatory Commission and all six state commissions must approve the sale. However, the companies will not require Securities and Exchange Commission approval, which could have been a meaningful hurdle, because the Energy Policy Act of 2005 repealed the Public Utilities Holding Company Act (PUHCA) in August. ScottishPower shareholders approved the sale in July 2005.

PacifiCorp has asked the six commissions to rule by February 2006 to enable the transaction to close by the end of PacifiCorp's fiscal year ending March 31, 2006. The terms of the purchase provide that the sale must be completed by May 2006; however, if all conditions are satisfied except the regulatory approvals, either the buyer or seller may extend the purchase agreement until February 2007.

Short-term rating factors

The short-term rating on ScottishPower, Scottish Power U.K. PLC, and PacifiCorp is 'A-2'. ScottishPower's consolidated liquidity is good, owing to a steady, predictable net cash flow stream produced by regulated businesses, minimal debt maturities over the next few years, and good credit facility capacity. Cash and other short-term deposits, which amounted to about £1.75 billion ($3.2 billion) at March 31, 2005, are held in a variety of quickly accessible funds. Full capacity exists under a $1 billion revolving credit facility, split between a $625 million facility and a $375 million facility, both due in 2008. ScottishPower U.K. maintains a $2 billion Euro-commercial paper program, which is undrawn.

PacifiCorp provides for its own liquidity needs. Its cash and cash equivalent position was $168 million as of June 30, down from the $199 million as of year-end fiscal 2005. In addition, it has an $800 million commercial paper program that is backstopped by a currently undrawn revolving credit agreement that terminates in May 2007. Short-term debt balances totaled $314 million as of the same date. Regulatory authorities limit PacifiCorp from issuing more than $1.5 billion in short-term debt.

Additional cash will be provided in the coming year in the form of planned equity contributions from PHI. The purchase agreement specifies that ScottishPower via PHI make a common equity contribution to PacifiCorp in quarterly amounts that total $500 million per year for fiscal 2006, rising to $526 million in fiscal 2007. (The latter year amount will be refunded to PHI in terms of an increased sale price to ScottishPower if the transaction closes.) Net

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of dividends from the utility, which are capped in the acquisition agreement, in fiscal 2006 PHI/ScottishPower cash equity contributions to PacifiCorp will be roughly $285.2 million. In contrast, in fiscal 2005, PacifiCorp's dividends paid to PHI totaled about $195 million, and no equity investments were made.

Future maturities of $289 million in fiscal 2006 are in line with historic obligations. Affiliate transaction rules restrict PacifiCorp from lending to any of PHI's subsidiaries or U.K. affiliates.

Ratings List

PacifiCorp	
Corp credit rating	A-/Watch Neg/A-2
Ratings assigned	
First mortgage bonds	A-/Watch Neg
Senior unsecured obligations	BBB+/Watch Neg

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search.

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Exhibit Accompanying Direct Testimony of Mahendra B. Shah

Fitch Ratings
Global Power/North America Special Report
February 13, 2006

February 2006

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Corporate Finance

Global Power/North America
Special Report

U.S Electric Utilities

Credit Implications of Commodity Cost Recovery

Analysts
Philip W. Smyth, CFA
+1 212 908-0531
philip.smyth@fitchratings.com

Ari Kagan, CFA
+1 212 908-0644
ari.kagan@fitchratings.com

Robert Hornick
+1 212 908-0523
robert.hornick@fitchratings.com

Related Research
- U.S. Power and Gas 2006 Outlook, Special Report, Dec. 15, 2005.

Key Points
- Most IOUs have approved energy cost-recovery mechanisms in place but with wide differences in individual plans.
- Energy cost-adjustment mechanisms are subject to political and regulatory risk.
- This report provides examples of energy cost-recovery plans that provide high, medium and low financial protection to the utility.
- High and rising commodity prices bear many risks for utilities (such as demand destruction, increasing customer delinquencies, higher working capital needs) that are beyond the scope of this report.

■ Rising Commodity Costs and Recovery

Volatile and rising energy commodity prices represent a challenge to investor-owned electric utility companies. Many state regulatory commissions have approved procedures allowing utilities in their jurisdiction to adjust tariffs periodically to reflect the actual cost of fuel and purchased power. However, the plans in place for individual companies vary significantly in their timing and effectiveness. Also, the implementation of the rate adjustments is still subject to regulatory and political risk, particularly in a period of rising energy costs. Recent political/regulatory developments in Arizona, Delaware, Illinois and Maryland underscore potential challenges to the industry's creditworthiness, as policy makers seek to shield their constituents from the negative effects of rising commodity costs. Just this year, Fitch Ratings downgraded Arizona Public Service Co.'s (APS) senior unsecured debt to 'BBB' from 'BBB+' and revised Commonwealth Edison Co.'s Rating Outlook to Negative from Stable, reflecting recent regulatory/political developments. While policy changes in worst case scenarios could result in significantly reduced cash flow, liquidity constraints and isolated insolvencies (especially for distribution utilities), a more gradual deterioration of creditworthiness as regulators attempt to minimize rising consumer rates is a more common concern.

While not within the scope of this report, rising and high commodity costs have other detrimental credit effects on liquidity as well as capacity utilization as a result of demand destruction. Combined, these emerging analytical issues form the basis for Fitch's cautious outlook on the sector (for more information, see U.S. Power and Gas 2006 Outlook on www.fitchratings.com).

Since Fitch's last survey on this topic in January 2005 (Outlook 2005: U.S. Power & Gas), a number of utilities previously subject to frozen rates have emerged from their transition plans or rate settlements. Currently, the majority of investor-owned utilities (IOUs) in Fitch's rating universe (including both vertically integrated and distribution-only investor-owned electric utilities) have commodity cost-recovery mechanisms designed to mitigate variations in utility operating cash flow due to commodity price fluctuations. Others, representing a small and declining proportion of the industry, still operate under multiyear rate plans that bar them from adjusting consumers' rates to recover rising energy costs or can only adjust rates to reflect changes in commodity costs via time-consuming and uncertain general rate case filings.

A utility's ability to weather a period of high and rising commodity costs is influenced by many related factors, including the state's market structure, rules regarding power procurement and the utility's obligation to serve customers' energy needs, the utility's resource mix relative to its load requirement, access to adequate liquidity and the state's regulatory/political environment. Within this context, effective and timely commodity cost-adjustment mechanisms provide utilities with greater assurance of ultimate recovery in a rising energy price environment. The Utility Energy Cost Recovery Mechanisms table on page 3 includes a list of generic factors that Fitch views as more or less protective of utility credit quality.

It is important to recognize that in addition to reliance on these regulatory mechanisms, utilities may also manage commodity price exposure through efficient operation of generation facilities, a diversified fuel mix and appropriate hedging, including physical and financial contracts. Although this report focuses on regulatory tariff-adjustment mechanisms, Fitch's ratings consider the full gamut of mitigants.

Restructured electric distribution utilities that primarily purchase power under short- to intermediate-term contracts to meet their load requirements are most reliant on the ability to pass through rising commodity costs to ratepayers on a timely basis. These utilities are generally perceived to have relatively low commodity risk profiles as a result of the legislative, regulatory and contractual arrangements that transfer commodity risk to suppliers and/or ratepayers.

However, distribution utilities are particularly vulnerable to adverse legislative/regulatory changes during a prolonged period of profoundly higher energy commodity prices if policy makers seek to mitigate the economic effect on consumers. In a worst case scenario in which regulatory or legislative action blocks the recovery of rising commodity costs from consumers, utilities would be forced to absorb the incremental costs, resulting in negative cash flows, increasing debt, strained liquidity and potential insolvency. Integrated electric utilities with a diverse fleet of coal or uranium-based generating assets are better positioned to stabilize prices to their consumers in the near to intermediate term in a high commodity cost environment, thereby avoiding adverse regulatory results.

Fitch believes that suspension of an approved fuel-recovery mechanism is a low probability, albeit not unprecedented, event. During the energy crisis of 2000–2001, California enacted legislation that impeded San Diego Gas & Electric Co.'s ability to pass through wholesale power commodity costs to customers. The legislation, Assembly Bill 265, imposed a 6.5 cents per kilowatt-hour ceiling on the amount of energy costs that could be billed to small-usage customers. However, it is important to note that all of the resulting deferred balances were eventually recovered in rates.

The potential risk is underscored by ongoing regulatory uncertainty in Illinois. Several parties have appealed an Illinois Commerce Commission ruling permitting utilities to procure power for retail customers beginning on Jan. 1, 2007, at market-based rates through a "New Jersey-style" competitive auction. Fitch believes the most likely outcome is a negotiated settlement that defers some portion of procurement costs for future recovery. The effect on credit quality will depend on the amount and length of any deferral.

Even when regulations that uphold the existing commodity cost-recovery mechanisms are maintained, utilities may be exposed to political pressure to mitigate rate shock for customers. For example, in Maryland, Governor Robert Ehrlich recently pressed the Maryland Public Service Commission (PSC) to investigate ways to ease the transition to market-based electricity rates for Baltimore Gas and Electric Company (BGE) residential customers when the rate freeze period ends on June 30, 2006. In response, the PSC stated that it does not believe Maryland's competitive power procurement model is flawed but will examine possible energy cost deferrals to decrease rate shock.

The Maryland PSC Staff proposed a two-year rate-stabilization plan, which includes energy cost deferrals for the first nine months and full recovery of such costs over the subsequent 15 months. While the staff proposal is not binding on the commission, Fitch believes that adoption of the staff proposal by the PSC would be neutral for the credit quality of BGE and its corporate parent, Constellation Energy Group. Similarly, Delaware Governor Ruth Ann Minner recently directed state regulators to explore methods to mitigate significant cost increases due to occur on May 1, 2006, which in Fitch's view appear likely to result in deferred energy costs for Delmarva Power & Light Company.

■ Background

The denouement of industry restructuring in the United States to date resulted in a "one foot in, one foot out" industry structure that provides a

Utility Energy Cost-Recovery Mechanisms

	Favorable		Unfavorable	
Element	**Characteristics**	**Examples**	**Characteristics**	**Examples**
Degree of Coverage	Recovery mechanism covers all energy costs.	Alabama Power Company, Oklahoma Gas & Electric Co., Potomac Electric Power Co., Connecticut Light & Power Co., Public Service Electric & Gas Co.	No cost-recovery mechanism exists in the jurisdiction and fuel/ purchased power cost recovery is addressed within the context of general rates cases.	PacifiCorp, AmerenUE, Public Service Co. of New Mexico, Tucson Electric Power Co.
			FAC only covers a portion of energy costs.	Idaho Power Co., Avista Corp., Arizona Public Service Co.
Timing	Energy rates are adjusted frequently to reflect market changes (e.g., monthly or quarterly)	Entergy Louisiana LLC, Northern Indiana Public Service Co., Southwestern Public Service Co., NorthWestern Corporation	Energy rates are adjusted infrequently (e.g., annually) or are frozen.	Public Service Co. of New Mexico, Appalachian Power Co., Metropolitan Edison Company, Pennsylvania Electric Company, AmerenUE, Progress Energy Carolinas,
	Utility may request out-of-cycle adjustments, triggered by quantitative or qualitative factors.	California utilities, Nevada Power Co., Sierra Pacific Power Company, Wisconsin Electric Power Co., FPL Group, Inc., TECO Energy, Inc., Progress Energy Florida	No modifications to the energy rate outside of predetermined dates may be made.	Consumers Energy Co., Detroit Edison Co.
	Any existing deferred energy costs are recovered over a short time frame.	Entergy Louisiana LLC, Entergy Mississippi Inc.	Deferred energy costs are recovered over an extended period.	Nevada Power Co., Sierra Pacific Power Company, Avista Corp.
Key Assumptions	Recovery mechanism utilizes forward-looking energy prices.	Nevada Power Co., Sierra Pacific Power Company, Pacific Gas & Electric, San Diego Gas & Electric Co., Southern California Edison Co.	Recovery mechanism utilizes historical energy prices or conditions.	PacifiCorp and Portland General Electric Company's Oregon rates assume normal hydro conditions each year.

FAC – Fuel and/or purchased power tariff-adjustment mechanism. Source: Fitch Ratings.

complicated patchwork of regulations, policies and risk-reward propositions for utility managements and fixed-income investors. In the early to mid-1990s, some states devised regulatory plans to separate the integrated electric utility business into its functional components, composed of generation, transmission and distribution operations.

Many utilities and state commissions entered into transition plans that capped or froze customer rates at lower levels over a multiyear period in return for providing the utilities with an opportunity to recover stranded generation investment in rates. As part of the bargain, fuel and purchase power cost-adjustment mechanisms were jettisoned, with cash flows from presumably stable or declining commodity costs expected to facilitate recovery of the utilities' uneconomic generation investment. At the end of the transition period, customer rates would be adjusted to reflect the expected lower, market-based wholesale power costs.

Skyrocketing energy costs and supply disruptions associated with the energy crisis of 2000–2001 brought restructuring efforts to a halt. Several states, including Arizona, California, Nevada, New Mexico and Ohio, have ended or delayed efforts to deregulate generation, and others could adjust restructuring plans to mitigate the effect of volatile commodity costs on consumers.

■ Integrated Electric Utilities

Commodity exposure for many vertically integrated electric utilities is meaningfully reduced by regulatory mechanisms that facilitate the timely recovery of variable fuel and purchased power costs. For other integrated utilities, the effectiveness of regulatory recovery mechanisms is diminished by sharing arrangements and dead-bands that can cause the utility's actual variable power and fuel costs to fluctuate significantly from amounts actually recovered in rates.

In addition to regulatory protections against commodity price risk, integrated utilities are able to mitigate risk through the efficient operation of owned generation, effective procurement and hedging policies. Commodity price risk is a greater concern for electric utilities that are short generating capacity or dependent on volatile natural gas-fired or variable hydroelectric generating resources.

High Protection

A significant proportion of integrated electric IOUs operate under power and fuel-adjustment clauses that adjust variable consumer rates to recover commodity costs on a monthly or quarterly basis. Some commodity cost pass-through arrangements with less frequent tariff adjustments are, nonetheless, able to provide highly effective commodity cost protection via trigger mechanisms that adjust consumer rates more frequently if a deferral balance meets or exceeds a relatively modest percentage of revenues. For example, procurement costs for the California IOUs are reviewed semiannually. However, the utilities are permitted to file for recovery of procurement supply costs if the expected deficiency is projected to exceed 5% of revenue, excluding revenue collected for the California Department of Water Resources. Similarly, the fuel and purchased power recovery clause in effect in Florida provides for recovery of prudently incurred fuel and purchased power costs. While Florida's cost-recovery mechanism is based on 12-month projections and reviewed annually, intermediate adjustments are permitted if projected fuel and purchased power costs are 10% over or under initially forecasted energy costs for the period.

Moderate Protection

Many integrated utilities are subject to mechanisms that adjust rates to reflect changing commodity costs relatively infrequently (annually) or include incentives, such as dead-bands, in which the cost/benefit of higher/lower than anticipated commodity costs are retained by the IOU within a predetermined range. In addition, some mechanisms also include a sharing between the utility and ratepayers of a portion of the cost/benefit caused by unanticipated fluctuations in commodity costs. All such mechanisms tend to boost the utility's retained cash flow when commodity costs are falling but result in some shortfall when commodity prices rise

An example is Avista Corp.'s (AVA) energy recovery mechanism (ERM), which was approved by Washington regulators to facilitate commodity cost recovery in the wake of the energy crisis of 2000–2001. Under the ERM, AVA retains the first $9 million of commodity cost or benefit, passing through to customers 90% of the deviations from actual energy costs over the initial $9 million dead-band (AVA filed a request with Washington regulators to remove the dead-band retroactive to Jan. 1, 2006). Similarly, IDACORP, Inc. subsidiary Idaho Power Co. passes through 90% of the deviations from actual commodity costs to its Idaho ratepayers but unlike AVA, has no dead-band.

In addition, mechanisms that spread recovery of deferred balances over multiyear periods provide some protection but may be a source of concern for fixed-income investors. Examples include Sierra Pacific Resources' electric operating subsidiaries, Nevada Power Co. (NPC) and Sierra Pacific Power Company (SPPC). Under Nevada regulation, deferred energy costs incurred by NPC and SPPC may be recovered over a one- to three-year period, depending on the vote of the commission, with the period for recovery and the amount recoverable determined after the fact. Nevada has had a prior record of disallowing recovery, but recoveries have been permitted over the past two years. Positively, the base tariff energy rate utilizes forward energy prices and may now be adjusted more frequently to reduce deferral balances.

Low Protection

Integrated electric utilities in this group do not have access to standardized variable fuel and purchased power cost-adjustment mechanisms, depending rather on full rate case filings to recoup unrecovered variable costs. Scottish Power PLC subsidiary PacifiCorp (PPW) currently operates without a commodity cost pass-through mechanism and can only recover its procurement costs through general rate case proceedings. In its Oregon jurisdiction, variable fuel and purchased power costs are adjusted annually through its resource variation mechanism. PPW filed for adjustment clauses in Oregon, Utah, Washington and Wyoming. Also included in this group are utilities operating under multiyear rate plans that establish frozen or capped rates. UniSource Energy Corporation subsidiary Tucson Electric Power Co. (TEP) in Arizona and PNM Resources subsidiary Public Service Co. of New Mexico

(PSNM) in New Mexico are representative of utilities operating under multiyear rate freeze or cap arrangements.

PSNM is operating under a rate-settlement agreement with fixed rates through 2007, while TEP is operating under a restructuring plan with capped rates through 2008. However, TEP filed for approval of a mechanism designed to recover incremental commodity cost fluctuations. A recent administrative law judge's proposed decision rejected the company's request. While the proposed decision is not binding on the commission, the probability of its adoption in light of the recommendation is meaningfully reduced in Fitch's view. A final order is expected shortly.

Utilities that recently received regulatory approval of fuel and purchase power cost-recovery mechanisms include Pinnacle West Capital Corp. (PNW) subsidiary APS and Westar Energy (WR). Both utilities completed general rate cases in 2005 that authorized the implementation of power supply adjustment mechanisms. WR is expected to move from the low- to high-protection category, assuming the adjustor is implemented smoothly. However, Fitch recently lowered PNW's and APS' ratings, reflecting the reluctance of regulators in Arizona to pass through prudently incurred energy costs in a timely manner.

Fitch notes that individual utilities in these states are free to mitigate their cash flow risk by entering into financial hedges and/or by owning or contracting for generation and transmission facilities in excess of customers' estimated demands. Thus, while a regulatory mechanism may be absent or not protective, it does not necessarily mean that the utility is at high risk.

■ Pure Electric Distributors

While, approximately one-half of the nation's 50 states have enacted some form of restructuring legislation, a relatively small number of jurisdictions, including Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Montana, New Jersey, New York, Pennsylvania, Rhode Island, Texas and Washington, D.C., have separated generation from utility distribution operations, thereby creating pure distribution utilities. Nearly all of the pure electric distribution operating utilities in the global power investor-owned electric universe are expected to fully recover their variable power costs through regulatory mechanisms and thus, are insulated from commodity price fluctuations, barring unanticipated regulatory/legislative changes. However, existing regulatory structures offer varying degrees of protection.

High Protection

Utilities that retained little or no power generation capacity and still have the obligation to serve customer demands at "standard-offer" rates generally hedged their load obligations by contracts with third-party suppliers (either power marketers or affiliate generators). If these are full-requirements contracts, the power provider is obligated to deliver a set percentage of the fluctuating customer demand, undertaking many different aspects of commodity volume and price risk.

In recent years, transition periods have ended in a number of jurisdictions, particularly in the Mid-Atlantic and Northeast, and restructuring plans have allowed utilities to hold competitive auctions for power supply under full-requirements contracts, with a simultaneous regulatory resetting of consumer tariffs to pass through all costs of the contracts that result from the auction. Even in the event of a supplier default, it is likely these utilities would eventually be able to recover any incremental power supply costs.

Some distribution utilities that still operate under industry restructuring transition plans with frozen generation rates may nonetheless be shielded from commodity price exposure if legislation provides explicit protection to the distribution utilities in the event of increases in power supply costs. For example, in Delaware, Delmarva Power & Light Company has had the ability during its transition period to file for a rate increase if fuel/purchased power costs exceed 115% of those reflected in capped rates. Without explicit means for adjusting rates if power supply costs exceed capped generation rates, regulatory support remains crucial to protecting utility financial health. An example of such regulatory support occurred in Massachusetts in 2000. Though state legislation in Massachusetts did not explicitly provide for adjustments to standard-offer rates if energy costs rose above prespecified fixed levels, the Department of Telecommunications and Energy demonstrated its willingness to prevent financial harm to the distribution utilities by increasing customer tariffs during a period of extraordinary commodity price increases.

Under Texas and Maine restructuring law, distribution utilities have no provider of last resort (POLR) obligation to procure energy for customers and do not take title to power delivered to end-users. As a result, distribution companies operating in these jurisdictions have no commodity risk.

Moderate Protection

Distribution utilities operating under transition plans that include POLR or standard-offer generation service at predetermined rates with no mechanism to reflect commodity variations in tariffs would appear to present a high-risk profile. However, most utilities operating under such plans have entered into long-term contracts with affiliates and/or unaffiliated energy companies to meet their supply requirements for the duration of their transition plans. These contracts effectively shift volume and price-related commodity risk associated with the distribution company's standard-offer or POLR obligation to the supplier and are subject to counterparty credit risk. Accordingly, Fitch focuses carefully on the credit profile of suppliers.

To the extent that these counterparties perform their supply obligations, the distributors should remain insulated from gas and power price movements. However, if there is a default by a power provider, the distributor could be exposed to higher power prices, particularly if generation rates are capped. This was a concern for Connecticut Light & Power Co. (CL&P) and Potomac Electric Power Co. (PEPCO) during 2003 when their respective power suppliers, NRG Energy, Inc. and Mirant Corp., who were providing electricity under contracts, filed for bankruptcy protection.

While both CL&P and PEPCO have since emerged from their respective frozen rate periods, distribution utilities operating in Illinois and Pennsylvania, including Commonwealth Edison Co., PECO Energy Co. and PPL Electric Utilities Corporation, have a potentially higher level of commodity price exposure.

Low Protection

Distribution utilities that are operating under regulatory schemes that include an extended rate freeze and POLR obligation without matching long-term fixed-price supply contracts in place are the least protected from high commodity price levels, in Fitch's view.

FirstEnergy Corp. subsidiaries Metropolitan Edison Company (MetEd) and Pennsylvania Electric Company (PenElec) operate under regulatory transition plans that include fixed energy tariffs through 2010. However, MetEd's and PenElec's supply contracts with unregulated affiliate FirstEnergy Solutions (FES) is renewed annually and subject to cancellation by FES with 60 days notice. Under Pennsylvania law, Fitch believes MetEd and PenElec would be exposed to market prices for replacement power if FES opted out of the supply contract (see tables on pages 10–11 for additional detail on electric distributors).

Fuel/Purchased Power Price Exposure of Integrated Utilities

(As of January 2006)

Company	State	Cost-Recovery Mechanism?	Generation Rates Frozen? Until?	Comment
Alabama Power Company	Ala.	Yes	No	Fuel cost-recovery adjustments are discretionary and can be filed as needed. The current fuel adjustment is scheduled to reset automatically in two years, but can be changed sooner.
AmerenUE	Mo.	No	Yes, June 2006.	Recently enacted legislation permits utilities to seek approval of a fuel and purchased power cost-recovery mechanism in a general rate case filing. The company is expected to request approval for an adjustment mechanism after the current rate freeze expires in April 2006.
Appalachian Power Co.	Va.	Yes	Yes, December 2010.	Company has ability to file for changes in fuel factor annually.
	W.Va.	No	No	Company has requested re-establishment of fuel-adjustment clause in pending rate proceedings.
Aquila Inc.	Kan.	Yes	No	Energy cost adjustment reset monthly.
	Mo.	No	No	January 2006 rate settlement includes forecast cost of fuel and purchased power for 2006. Fuel-adjustment mechanism unlikely until Missouri Public Utility Commission formalizes rules later this year.
	Colo.	Yes	No	Annual adjustment mechanism provides for fuel and energy costs that differ from amounts reflected in base rates to be allocated 75% to customers and 25% to the company. Company must file by July 1, 2006, to extend this mechanism or propose a new one.
Arizona Public Service Co.	Ariz.	Yes	No	Annual power supply adjustor authorized in 2005 provides for deferral and recovery of 90% of power cost deviations from base rates with certain limitations.
Avista Corp.	Idaho	Yes	No	Annual fuel-adjustment mechanism is designed to pass through 90% of power costs.
	Wash.	Yes	No	Annual fuel adjustment mechanism is designed to pass through 90% of power costs. Mechanism includes a $9 million dead-band.
Central Illinois Light Company	Ill.	No	Yes, Through December 2006	The Illinois Commerce Commission authorized utilities in Illinois to procure power for retail customers beginning Jan. 1, 2007, at market-based rates through a competitive auction to be conducted in the fall of 2006. Because of opposition by the governor and pending legal appeals, the procurement process and recovery of procurement costs is uncertain.
Central Vermont Public Service Corp.	Vt.	No	No	Fuel and purchased power costs are recovered through base rate filings.
Cincinnati Gas & Electric Co.	Ohio	Yes	No	Rate-stabilization plan in place through 2008 allows recovery of most fuel and purchased power costs monthly, while certain other purchased power expenditures are tracked and recovered annually.
Cleveland Electric Illuminating Co.	Ohio	Yes	Yes, December 2008	Commodity costs in excess of amounts reflected in rates may be deferred and recovered through distribution rates over 25 years after December 2008.
Columbus Southern Power Co.	Ohio	No	Yes, December 2008	No automatic fuel and purchase power adjustment mechanism is in place, but the rate-stabilization plan allows the company to seek recovery of environmental costs.
Consumers Energy Co.	Mich.	Yes	No	Annual recovery mechanism has been reinstated for all customers with the expiration of rate caps.
Dayton Power & Light Company	Ohio	No	Yes, December 2010	Recent settlement provides for an annual $65 million surcharge (net of customer refunds) for fuel costs and other expenses.
Detroit Edison Co.	Mich.	Yes	No	Annual recovery mechanism has been reinstated for all customers with the expiration of rate caps.
Duke Energy Corp.	N.C.	Yes	Yes, December 2007	Base rates in North Carolina are subject to a rate freeze through 2007, but annual fuel-adjustment clause is excluded from rate freeze and remains in effect.
	S.C.	Yes	No	Fuel and purchased power costs are reset annually.
Entergy Arkansas Inc.	Ark.	Yes	No	Fuel and purchased power costs are reset annually.
Entergy Gulf States Inc.	Texas	Yes	Yes, June 2008.	Fuel and purchased power costs are reset semiannually.
	La.	Yes	No.	Fuel rate is reset monthly.
Entergy Louisiana LLC	La.	Yes	No	Fuel and purchased power costs are reset monthly.
Entergy Mississippi Inc.	Miss.	Yes	No	Fuel and purchased power costs are reset monthly.
Florida Power & Light Co.	Fla.	Yes	No	Fuel and purchased power costs are reset annually based on projected costs. Intermediate adjustments are permitted if projected fuel revenue are 10% over or under projected fuel costs for the period.

N.A. – Not applicable. POLR – Provider of last resort. Source: Company reports and Fitch Ratings. Continued on next page.

Fuel/Purchased Power Price Exposure of Integrated Utilities (continued)

(As of January 2006)

Company	State	Cost-Recovery Mechanism?	Generation Rates Frozen? Until?	Comment
Georgia Power Company	Ga.	Yes	No	Fuel cost-recovery adjustments are discretionary and can be requested as needed. Under-recovered balance has a +/- $50 million band that is reviewed every six months.
Gulf Power Company	Fla.	Yes	No	Fuel and purchased power costs are reset annually based on projected costs. Intermediate adjustments are permitted if projected fuel cost variations are 10% of amounts reflected in rates.
Idaho Power Co.	Idaho	Yes	No	Annual fuel-adjustment mechanism is designed to pass through 90% of power costs.
Indiana Michigan Power Co.	Ind.	No	Yes, 2007	June 2005 settlement capped fuel rates through 2007.
	Mich.	Yes	No	Fuel and purchased power costs are reset annually.
Indianapolis Power & Light Co.	Ind.	Yes	No	Annual adjustment clause was modified in 2005 and is now reset based on futures price of gas and No. 2 fuel oil.
Kansas Gas & Electric Co.	Kan.	Yes	No	Monthly rate reset. Deferred costs are passed through to customers annually.
Kentucky Power Co.	Ky.	Yes	No	Fuel and purchased power recovery mechanism adjusted monthly.
MDU Resources Group, Inc.	N.D., S.D.	Yes	No	Schedules allow company to reflect increases or decreases in fuel and purchased power costs (excluding demand charges) on a monthly basis.
	Wyo.	Yes	No	Expedited rate filing procedures allow company to annually reflect increases in purchased power costs.
	Mont.	No	No	Fuel and purchased power cost changes are addressed in the context of general rate filings.
MidAmerican Energy Company	Iowa	No	No	In Iowa, fuel and purchased power costs are recoverable through a base rate filing.
	Ill., S.D.	Yes	No	Fuel and purchased power costs are reset monthly.
Mississippi Power Company	Miss.	Yes	No	Company's fuel cost-recovery factor is reset annually. Company can earn a return on the on the under-recovered fuel balance through the retail energy cost-management clause.
Monongahela Power Co.	W.Va.	No	No	The company's energy adjustment clause was suspended in 2000.
Nevada Power Co.	Nev.	Yes	No	No automatic fuel-adjustment clause exists in Nevada. However, company initiates a deferred energy rate case annually to recover or refund any balances and establish a new base energy rate.
Northern Indiana Public Service Co.	Ind.	Yes	No	Utilities may adjust rates for changes in fuel and purchased power (energy component only) every three months following hearings.
Northern States Power Co. (Minn.)	Minn.	Yes	No	Fuel and purchased power cost recovery based on forecasted monthly costs and a subsequent monthly true-up to actual costs.
Northern States Power Co. (Wisc.)	Wisc.	No	No	Costs recovered through base rate cases filed every other year for a test period beginning the following January.
Ohio Edison Co.	Ohio	Yes	Yes, December 2008	Commodity costs in excess of amounts reflected in rates may be deferred and recovered through distribution rates over 25 years after December 2008.
Ohio Power Co.	Ohio	No	Yes, December 2008	No automatic fuel and purchase power adjustment mechanism is in place, but the rate-stabilization plan allows the company to seek recovery of environmental costs.
Oklahoma Gas & Electric Co.	Okla.	Yes	No	Fuel costs are reset semiannually.
Pacific Gas & Electric	Calif.	Yes	No	Procurement costs are reset semiannually. More frequent adjustments are permitted when over/under collections exceed 5% of the prior year's procurement revenue.
PacifiCorp	Utah, Wyo., Wash.	No	No	Fuel and purchased power costs are recovered through base rate filings.
	Ore.	Yes	No	No automatic fuel-adjustment clause but variable power costs are reset annually through company's resource valuation mechanism.
Pennsylvania Power Company	Penn.	No	Yes, December 2006	Company currently meets its supply needs through a full-requirements contract with affiliate generation company. Beginning Jan. 1, 2007, the company is expected to procure power for its POLR obligation at market-based rates.
Portland General Electric Company	Ore.	Yes	No	No automatic fuel-adjustment clause but variable power costs are reset annually through company's resource valuation mechanism.
Progress Energy Carolinas	N.C.	Yes	Yes, Dec. 31, 2007	Adjustments are made annually.
	S.C.	Yes	No	Fuel and purchased power costs are reset semiannually.

AEP – American Electric Power Co., Inc. POLR – Provider of last resort. Source: Company reports and Fitch Ratings. Continued on next page.

Fuel/Purchased Power Price Exposure of Integrated Utilities (continued)

(As of January 2006)

Company	State	Cost-Recovery Mechanism?	Generation Rates Frozen? Until?	Comment
Progress Energy Florida	Fla.	Yes	Yes, Dec. 31, 2009	Fuel and purchased power costs are reset annually based on projected costs. Intermediate adjustments are permitted if projected fuel revenue are 10% over or under projected fuel costs for the period.
PSI Energy, Inc.	Ind.	Yes.	No	Fuel and purchased power costs are reset quarterly.
Public Service Co. of Colorado	Colo.	Yes	No	Sliding scale provides for sharing of over- or under-recoveries of power supply costs. Maximum exposure is limited to $11.25 million annually. Recovery mechanism expires on Dec. 31, 2006, and the company must file to request a new mechanism by April 1, 2006.
Public Service Co. of New Hampshire	N.H.	Yes	No	No automatic fuel-adjustment clause but any excess purchased power and fuel costs above what is embedded in rates is recovered through its stranded cost-recovery charge.
Public Service Co. of New Mexico	N.M.	No	Yes, December 2007	Fuel and purchased power costs are recovered through base rate filings.
Public Service Co. of Oklahoma	Okla.	Yes	No	Fuel-adjustment clause is reset annually.
San Diego Gas & Electric Co.	Calif.	Yes	No	Procurement costs are reset semiannully. More frequent adjustments are permitted when over/under collections exceed 5% of the prior years procurement revenue.
Sierra Pacific Power Company	NV	Yes	No	No automatic fuel-adjustment clause exists in Nevada. However, company initiates a deferred energy rate case annually to recover or refund any balances and establish a new base energy rate.
South Carolina Electric & Gas Co.	S.C.	Yes	No	Electric fuel and purchased power costs are adjusted annually. More frequent adjustments are allowed if circumstances dictate.
Southern California Edison Co.	Calif.	Yes	No	Procurement costs are reset semiannully. More frequent adjustments are permitted when over/under collections exceed 5% of the prior year's procurement revenue.
Southwestern Electric Power Co.	La.	Yes	Yes, Pending a financial review.	Although base rates remain frozen, fuel and purchased power costs are reset annually.
	Ark., Texas	Yes	No	Fuel and purchased power costs are adjusted annually.
Southwestern Public Service Co.	N.M.	Yes	No	Fuel cost-adjustment mechanism adjusted monthly.
	Texas	Yes	No	Fixed fuel factor adjusted at least semiannually or more often if needed.
Tampa Electric Company	Fla.	Yes	Yes, December 2006	Fuel and purchased power costs are reset annually based on projected costs. Intermediate adjustments are permitted if projected fuel revenue are 10% over or under projected fuel costs for the period.
Texas New Mexico Power Company	N.M.	No	Yes, December 2010	Relies on affiliate contract to meet its obligation to serve.
Toledo Edison Co.	Ohio	Yes	Yes, December 2008	Commodity costs in excess of amounts reflected in rates may be deferred and recovered through distribution rates over 25 years after December 2008.
Tucson Electric Power Co.	Ariz.	No	Yes, December 2008	Company filed a request to extend its current rate freeze through 2010 and implement a mechanism to pass through fuel and purchase power costs associated with incremental load growth.
Union Light, Heat & Power Company	Ky.	No	Yes, December 2006.	The company receives power supply through an affiliate contract and expects to file for new rates shortly.
Virginia Electric & Power Co.	Va.	No	Yes, December 2010	One opportunity to adjust the fuel factor after July 1, 2007.
Westar Energy	Kan.	Yes	No	Monthly rate reset. Deferred costs are passed through to customers annually.
Wisconsin Electric Power Co.	Wisc.	No	No	Allowed to request rate adjustments if actual monthly or annual costs exceed those built into rates by a prespecified range. Has applied for fuel-recovery mechanism in upcoming rate case.

Source: Company reports and Fitch Ratings.

Electric Distributors

(As of January 2006)

Company	State	Generation Rates Frozen? Until?	Generation Currently Being Supplied By
AEP Texas Central Co.	Texas	No	Distribution business has no POLR obligation, and deregulated generation is sold in wholesale markets and exposed to market conditions.
AEP Texas North Co.	Texas	No	Distribution business has no POLR obligation, and deregulated generation is sold in wholesale markets and exposed to market conditions.
AmerenCIPS	Ill.	Yes, Jan. 1, 2007	Contract with affiliate.
Atlantic City Electric Company	N.J.	No	Full-requirements contracts with several suppliers.
Baltimore Gas and Electric Company	Md.	Yes, July 1, 2006, for residential. On July 1, 2004, C&I customers began receiving power at market-based rates. Company faces the possibility of energy cost deferrals for residential power purchases beginning on July 1.	Affiliate for residential customers. Multiple suppliers for C&I customers.
Boston Edison Co.	Mass.	No	Power procured from multiple suppliers via competitive bidding process.
Cambridge Electric Light Company	Mass.	No	Power procured from multiple suppliers via competitive bidding process.
CenterPoint Energy Houston Electric, LLC	Texas	No	Retail energy providers. Company has no POLR obligation.
Central Hudson Gas & Electric Corp.	N.Y.	No	Primarily through contracts.
Central Maine Power Co.	Maine	No	Company has no POLR obligation.
Commonwealth Edison Co.	Ill.	Yes, Dec. 31, 2006	Affiliate contract.
	Mass.	No	Power procured from multiple suppliers via competitive bidding process.
Connecticut Light & Power Co.	Conn.	No	Power procured from multiple suppliers via competitive bidding process.
Consolidated Edison Co. of New York, Inc.	N.Y.	No	Power procured from a combination of long-term contracts with a variety of suppliers and spot market purchases.
Delmarva Power & Light Company*	Del.	Yes, May 1, 2006	Affiliate contract. Power will be procured through competitive energy bids beginning May 2006, when a significant rise in rates is expected. As in Maryland and Illinois, significant political pressure has emerged to mitigate rate shock.
	Md.	No	Power is now procured from several suppliers via competitive bids.
Duquesne Light Co.	Pa.	Yes, 2007 for residential customers. C&I customers can choose between fixed rates based on a request for proposal process or real-time hourly spot prices.	Affiliate contract.
Illinois Power Co.	Ill.	Yes, 2006.	Contract with Dynegy Inc.
Jersey Central Power & Light Company	N.J.	No	Power procured from multiple suppliers via competitive bidding process.
Metropolitan Edison Company	Pa.	Yes, Jan. 1, 2010	Long-term NUG and other third-party contracts and contract with affiliate.
New York State Electric & Gas Corp.	N.Y.	No	Power procured on the spot market and short-term contracts. Company has exposure to some potential margin squeeze because customers can choose fixed-rate option. Company seeks to hedge essentially all of this load. Fixed rate load accounts for approximately 60%.
NorthWestern Corporation	Mont., S.D., Neb.	No	Power procured under contracts with multiple suppliers.
Orange & Rockland Utilities, Inc.	N.Y.	No	Power procured from a combination of long-term contracts with a variety of suppliers and spot market purchases.
PECO Energy Co.	Pa.	Yes, Jan. 1, 2011	Affiliate contract.
Pennsylvania Electric Company	Pa.	Yes, Jan. 1, 2010	Long-term NUG and other third-party contracts and contract with affiliate.
Potomac Electric Power Co.	D.C., Md.	No	Power is procured from several suppliers via competitive bids.

*Delmarva Power & Light Company can file for a rate increase if fuel/purchased power costs exceed 115% of those reflected in capped rates. C&I – Commercial and industrial. POLR – Provider of last resort. NUG – Nonutility generator. Source: Fitch Ratings. Continued on next page.

Electric Distributors (continued)

(As of January 2006)

Company	State	Generation Rates Frozen? Until?	Generation Currently Being Supplied By
Potomac Edison Co.	Md.	Yes, Dec. 31, 2008, for residential. C&I now at market rates.	Affiliate contract. Beyond transition period, power will be supplied at market rates.
	Va.	Yes, Generation rates capped through Dec. 31, 2010 in Virginia.	Affiliate contract.
PPL Electric Utilities Corporation	Pa.	Yes, Jan. 1, 2010	Affiliate contract.
Public Service Electric & Gas Co.	N.J.	No	Power is procured from suppliers via a statewide competitive auction.
Rochester Gas & Electric Corporation	N.Y.	No	Company introduced fixed-rate option in 2005. Company seeks to hedge essentially all of this load through spot market and short-term contracts. Fixed rate load accounts for approximately 25%.
Rockland Electric Company	N.Y.	No	Power procured on the spot market and short-term contracts. Company introduced fixed-rate option in 2005. Company seeks to hedge essentially all of this load. Fixed-rate load accounts for approximately 25%.
Texas New Mexico Power Company	Texas	No	No POLR requirement.
TXU Electric Delivery Company	Texas	No	No POLR requirement.
West Penn Power Co.	Pa.	Yes, Dec. 31, 2010	Affiliate contract.
Western Massachusetts Electric Co.	Mass.	No	Power procured from multiple suppliers via competitive bidding process.

POLR – Provider of last resort. Source: Fitch Ratings.

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806 Shah Exhibit

Case UM-1129
Exhibit PPL/806
Witness: Mahendra B. Shah

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mahendra B. Shah

Incremental Cost Imposed by a Capital Lease or Imputed Debt

February 2006

Incremental Cost Imposed by a Capital Lease or Imputed Debt

Cost of equity less weighted average cost of capital
times amount of equity issued to rebalance capital structure
(Dollars in thousands)

		Capitalization	Cap Ratio (1)	Cost (1)	Weighted Cost	After-Tax Cost	Pre-Tax Cost
	Capital Structure - Beginning						
1	LT Debt	520,000	52.0%	7.0%	3.64%	2.26%	3.64%
2	Common	480,000	48.0%	11.0%	5.28%	5.28%	8.51%
3	TOTAL	1,000,000			8.92%	7.54%	12.15%
4	Capital Lease	100,000					
	Capital Structure - After Lease b4 Rebalancing						
5	LT Debt	620,000	56.4%				
6	Common	480,000	43.6%				
7	TOTAL	1,100,000					
	Rebalancing						
8	Issue Equity	92,300					
9	Retire Debt	-					
	Capital Structure - After Lease & Rebalancing						
10	LT Debt	620,000	52.0%	7.0%	3.64%	2.26%	3.64%
11	Common	572,300	48.000%	11.0%	5.28%	5.28%	8.51%
12	TOTAL	1,192,300			8.92%	7.54%	12.15%

Incremental cost imposed by the debt associated with a capital lease

13	Pretax cost of equity	17.73%
14	Pretax weighted cost of capital	12.15%
15	Difference	5.58%
16	Amount of equity issued to rebalance	92,300
17	**Annual revenue requirement impact**	**5,149**
18	Income tax rate	37.95%
19	Tax grossup factor	1.612

(1) Capital structure and costs are for illustrative purposes only and are not intended to reflect the company's current capital structure or costs.

825 N.E. Multnomah St.
Portland, OR 97232

PACIFICORP
PACIFIC POWER UTAH POWER

February 27, 2006

VIA ELECTRONIC FILING

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Vikie Bailey-Goggins, Administrator
Regulatory and Technical Support

Re: PacifiCorp's Direct Testimony and Exhibits in Phase II of Docket No. UM-1129

Enclosed for filing is an original and 5 copies of PacifiCorp's DirectTestimony and Exhibits in Phase II of Docket UM-1129. Copies of this filing have been served on the UM-1129 Service List.

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred):	datarequest@pacificorp.com.
By Fax:	(503) 813-6060
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 800 Portland, OR 97232
With copies to:	Katherine A. McDowell Stoel Rives LLP 900 S.W. Fifth Ave., Suite 2600 Portland, OR 97204 Telephone Nos. (503) 294-9602 Fax No. (503) 220-2480 Email: kamcdowell@stoel.com

Informal inquiries may be directed to Laura Beane, Regulatory Manager at (503) 813-5542.

Very truly yours,

D. Douglas Larson

D. Douglas Larson
Vice President, Regulation

cc: Service List
Enclosures

CERTIFICATE OF SERVICE

I hereby certify that on this 27th day of February 2006, I caused to be served, via Overnight delivery and or electronic mail, a true and correct copy of PacifiCorp's Direct Testimony and Exhibits in Phase II of Docket No. UM-1129

SARAH J. ADAMS LIEN
COUNSEL FOR PACIFICORP
900 SW FIFTH AVE. STE 2600
PORTLAND, OR 97204-1268
sjadamslien@stoel.com

MARK ALBERT
MARKETING & REGULATORY AFFAIRS
VULCAN POWER COMPANYH
1183 NW WALL ST. STE G
BEND, OR 97701
malbert@vulcanpower.com

RANDY ALLPHIN
IDAHO POWER COMPANY
P.O. BOX 70
BOISE, ID 83707-0070
rallphin@idahopower.com

MICK BARANKO
CONTROLLER
DOUGLAS COUNTY FOREST PRODUCTS
P.O. BOX 848
WINCHESTER, OR 97495
mick@dcfp.com

R. THOMAS BEACH
CROSSBORDER ENERGY
2560 NINTH ST – STE 316
BERKELEY, CA 94710
tomb@crossborderenergy.com

KARL BOKENKAMP
GENERAL MANAGER-POWER SUPPLY PLANNING
P.O. BOX 70
BOISE, ID 83707-0070
kbokenkamp@idahopower.com

LOWREY R. BROWN
CITIZENS' UTILITY BOARD OF OREGON
610 SW BROADWAY – STE 308
PORTLAND, OR 97205
lowrey@oregoncub.org

JOANNE M. BUTLER
IDAHO POWER COMPANY
P.O. BOX 70
BOISE, ID 83707-0070
jbutler@idahopower.com

BRIAN COLE
DIRECTOR, GOVT.&COMMUNITY RELATIONS
SYMBIOTICS, LLC
P.O. BOX 1088
BAKER CITY, OR 97814
bc@orbisgroup.org

BRUCE CRAIG
ASCENTERGY CORP
440 BENMAR DR. STE 2230
HOUSTON, TX 77060
bcraig@asc-co-com

RANDY CROCKET
CFO
D R JOHNSON LUMBER COMPANY
P.O. BOX 66
RIDDLE, OR 97469
randyc@drjlumber.com

CHRIS CROWLEY
100 E 19TH STE 400
VANCOUVER, WA. 98663
ccrowley@comumbiaep.com

CAREL DE WINKEL
OREGON DEPARTMENT OF ENERGY
625 MARION STREET NE
SALEM OR 07310
carel.dewinkel@state.or.us

CRAIG DEHART
MIDDLEFORK IRRIGATION DISTRICT
PO BOX 291
PARKDALE OR 97041
mfidcraig@gorge.net

ELIZABETH DICKSON
HURLEY, LYNCH & RE, PC
747 SW MILLVIEW WAY
BEND, OR 97702
eadickson@hhlr-law.com

JASON EISDORFER
CITIZENS' UTILITY BOARD OF OREGON
610 SW BROADWAY STE 308
PORTLAND, OR 97205
Jason@oregoncub.org

JOHN M. ERIKSSON
STOEL RIVES LLP
201 SOUTH MAIN ST.
SALT LAKE CITY, UT 84111
jmeriksson@stoel.com

JOHN R. GALE
IDAHO POWER COMPANY
P.O. BOX 70
BOISE, ID 83707-0070
rgale@idahopower.com

THOMAS M. GRIM
CABLE HUSTON BENEDICT ET AL
1001 SW FIFTH AVE. STE 2000
PORTLAND, OR 97204-1136
tgrim@chbh.com

STEVEN C. JOHNSON
CENTRAL OREGON IRRIGATION DISTRICT
2598 NORTH HIGHWAY 97
REDMOND, OR 97756
stevej@coid.org

MATTHEW W. PERKINS
DAVISON VAN CLEVE PC
1000 SW BROADWAY STE 2460
PORTLAND OR 97205
mwp@dvclaw.com

ALAN MEYER
WEYERHAEUSER COMPANY
698 12TH ST. STE 220
SALEM, OR 97301-4010
Alan.meyer@weyerhaeuser.com

THOMAS H. NELSON
THOMAS H. NELSON & ASSOCIATES
825 NE MULTNOMAH STE 925
PORTLAND, OR 97232

PORTLAND GENERAL ELECTRIC COMPANY
121 SW SALMON ST. 1WTC0702
PORTLAND, OR 97204
Pge.opuc.filings@pgn.com

PETER J. RICHARDSON
RICHARDSON & O'LEARY
PO BOX 1849
99 E STATE ST - STE 200
EAGLE ID 83616
peter@richardsonandoleary.com

IRION SANGER
DAVISON VAN CLEVE
333 SW TAYLOR STE 400
PORTLAND, OR 97204
ias@dvclaw.com

RANDALL J. FALKENBERG
RFI CONSULTING, INC.
PMB 362
8351 ROSWELL ROAD
ATLANTA, GA 30350
consultrfi@aol.com

J. RICHARD GEORGE
PORTLAND GENERAL ELECTRIC COMPANY
121 SW SALMON ST
PORTLAND OR 97204
richard_george@pgn.com

DAVID HAWK
J. R. SIMPLOT COMPANY
PO BOX 27
BOISE ID 83707
david.hawk@simplot.com

BARTON KLINE
IDAHO POWER COMPANY
P.O. BOX 70
BOISE, ID 83707-0070

JANET L. PREWITT
DEPARTMENT OF JUSTICE
1162 COURT ST NE
SALEM OR 97301-4096
janet.prewitt@doj.state.or.us

MONICA B. MOEN
IDAHO POWER COMPANY
P.O. BOX 70
BOISE, ID 83707-0070
mmoen@idahopower.com

LISA F. RACKNER
ATER WYNNE LLP
222 SW COLUMBIA ST. STE 1800
PORTLAND, OR 97201-6618
lfr@aterwynne.com

DON READING
6070 HILL ROAD
BOISE, ID 83703
dreading@mindspring.com

S. BRADLEY VAN CLEVE
DAVISON VAN CLEVE PC
1000 SW BROADWAY STE 2460
PORTLAND OR 97205
mail@dvclaw.com

LISA SWARTZ
PUBLIC UTILITY COMMISSION OF OREGON
P.O. BOX 2148
SALEM, OR 97308-2148
Lisa.c.schwartz@state.or.us

MARK TALLMAN
MANAGING DIRECTOR, TRADING
PACIFICORP
825 MULTNOMAH STE 600
PORTLAND, OR 97232-2153
Mark.tallman@pacificorp.com

MICHAEL T WEIRICH
DEPARTMENT OF JUSTICE
1162 COURT ST NE
SALEM OR 97301-4096
michael.weirich@state.or.us

LAURA BEANE
PACIFIC POWER & LIGHT
825 NE MULTNOMAH STE 800
PORTLAND OR 97232
laura.beane@pacificorp.com

PAUL WOODIN
WESTERN WIND POWER
282 LARGENT LANE
GOLDENDALE, WA 98620-3519
pwoodin@gorge.net

MICHAEL YOUNGBLOOD
IDAHO POWER COMPANY
P.O. BOX 70
BOISE, ID 83707
myoungblood@idahopower.com

BRUCE A. WITTMANN
WEYERHAEUSER
P.O. BOX 9777
FEDERAL WAY, WA 98063-9777
Bruce.wittmann@weyerhaeuser.com

LINDA K WILLIAMS
ATTORNEY AT LAW
10266 SW LANCASTER RD
PORTLAND OR 97219-6305

TOM YARBOROUGH
WEYERHAEUSER COMPANY
MAIL STOP CH 1K32
P.O. BOX 9777
FEDERAL WAY, WA 98063-9777

Peggy Ryan

Peggy Ryan
Supervisor Regulatory Administration