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August 13, 2004

VIA FACSIMILE, ELECTRONIC MAIL, AND
UPS OVERNIGHT MAIL

Administrative Hearings Division
Public Utility Commission
350 Capitol Street NE, Suite 215
Salem, OR 97310-0001

Attn: Honorable Traci Ann Kirkpatrick

Re: *In the matter of Portland General Electric Company,* **UM 1081**

Dear Judge Kirkpatrick:

Enclosed for filing, please find the original and five copies of EPCOR's Reply Brief in the above-referenced docket. A copy was electronically mailed, faxed today for filing and all parties were served as noted in the attached Certificate of Service.

Very truly yours,

PRESTON GATES & ELLIS LLP

By
Harvard P. Spigal
Carra Sahler

HPS:jm
Enclosure

cc: Service List

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UM 1081

In the matter of PORTLAND GENERAL ELECTRIC COMPANY Investigation Into Direct Access Issues for Industrial and Commercial Customers under SB 1149	EPCOR MERCHANT AND CAPITAL (US) Inc. **REPLY BRIEF**

I. INTRODUCTION

Pursuant to OAR §§ 860-014-0090 and 860-013-0040, and the Administrative Law Judge's ("ALJ") June 29, 2004, Ruling, EPCOR Merchant and Capital (US) Inc. ("EPCOR") submits this Reply Brief requesting that the Oregon Public Utility Commission ("Commission") reject those parts of PacifiCorp's proposed interim transition adjustment that are contrary to the evidence and the Commission's policy to encourage direct access, and to adopt EPCOR's changes to the proposed interim transition adjustment.

II. BACKGROUND

The Commission initiated these proceedings in *In the Matter of an Investigation Into Direct Access Issues for Industrial and Commercial Customers under SB 1149*,

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Commission Order No. 03-260. PacifiCorp filed a proposed transition adjustment to resolve issues in this docket on April, 14, 2004.

EPCOR filed Direct Testimony on May 27, 2004. Industrial Customers of Northwest Utilities ("ICNU") filed Direct Testimony on May 27, 2004. Oregon Public Utility Commission staff ("Staff") filed Direct Testimony on May 28, 2004. PacifiCorp filed Rebuttal Testimony on June 24, 2004. PacifiCorp's Rebuttal Testimony included a revised, proposed transition adjustment. ICNU filed Supplemental Testimony of Lincoln Wolverton on July 12, 2004. A hearing was held for the purpose of conducting cross-examination on July 14, 2004.

PacifiCorp, ICNU, Staff and EPCOR faxed or filed opening briefs on August 3, 2004. ALJ Kirkpatrick ordered reply briefs be due on August 13, 2004.

III. THE LAW

PacifiCorp erroneously relies on the ongoing valuation method to conclude that a transition credit is not justified for Bonneville Power Administration ("Bonneville") Formula Power Transmission ("FPT") service freed-up by direct access. PacifiCorp Reply Brief at 2-3. PacifiCorp's position is erroneous because the ongoing valuation method does not apply to third-party transmission service, including FPT service and transmission service PacifiCorp may purchase in the future to wheel power to its Oregon system, or PacifiCorp's own transmission assets

OAR 860-038-0140(1)[1] states that a company "may" use the ongoing valuation

[1] "An electric company may use an ongoing valuation method to determine transition costs or transition credits applicable to Oregon cost-of-service consumers until otherwise directed by the Commission. Except in the circumstances set forth in OAR 860-038-0085(5) and (6), an electric company will use an ongoing valuation method to determine the transition charges or transition credits applicable to Oregon cost-of-

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methodology, except as required by OAR 860-039-080(5). OAR 860-039-080(5) states, "The ongoing valuation method, as described in OAR 860-038-0140, *will* be used to establish transition charges and credits for *resources* that have not been sold or administratively valued." (emphasis added). The ongoing valuation method is used for determining "transition costs or benefits for a *generation asset* by comparing the value of the *asset output* at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period." OAR 860-038-005(41) (emphasis added).

IV. ARGUMENT

A. FPT Service Is Not A Generation Asset

Freed-up FPT service is neither generation, nor an asset; FPT service agreements are transmission, not generation, and they are a service provided by Bonneville in consideration for PacifiCorp's payment obligation, not an asset. Furthermore, PacifiCorp's claim that the ongoing valuation method should be applied to FPT service is inconsistent with PacifiCorp's description of FPT service. The evidence submitted by PacifiCorp would not permit the FPT rate to be compared with the market value for FPT service because there is not a liquid transmission market, according to PacifiCorp, and because there is no market for a transmission product that cannot be sold, according to PacifiCorp. Rebuttal Testimony of John A. Apperson, PPL Exhibit 205 at 6.

The Commission, nevertheless, has the responsibility under ORS 757.600 *et. seq.* to determine whether PacifiCorp's contracts for FPT transmission service are an

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service consumers." OAR 860-038-0140(1).

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uneconomic obligation[2] or an economic obligation[3] for which a transition adjustment may be allowed. See, EPCOR's Opening Brief at 6. Freed-up FPT service is uneconomic if the freed-up transmission service will not be used; however, FPT service is economic if the service will be used by PacifiCorp or another entity. PacifiCorp acknowledges that it expects to fully utilize its transmission capacity; therefore, FPT transmission service will not be stranded because of direct access. EPCOR Opening Brief at 20-21. EPCOR proposes a better solution than PacifiCorp utilizing this capacity, *i.e.*, that PacifiCorp enter into buy-sell arrangements with ESSs, assuring both use of FPT service and revenues for PacifiCorp to offset transition credits for direct access customers. *See*, EPCOR Opening Brief at 14-15. In either case, FPT transmission service will be economic within the meaning of ORS 757.600(10).

B. PacifiCorp Recovers FPT Costs In PacifiCorp's Cost-of-Service Rate, Energy Only

PacifiCorp proposes a transition calculation that includes PacifiCorp's cost-of-service energy rate. PacifiCorp derives its cost-of-service energy rate from PacifiCorp's

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[2] "'Uneconomic utility investment' means all Oregon allocated investments made by an electric company that offers direct access under ORS 757.600 to 757.667, including plants and equipment *and contractual or other legal obligations,* properly dedicated to generation, conservation and work-force commitments, that were prudent at the time the obligations were assumed but the full costs of which are no longer recoverable as a direct result of ORS 757.600 to 757.667, absent transition charges. 'Uneconomic utility investment' does not include costs or expenses disallowed by the Commission in a prudence review or other proceeding, to the extent of such disallowance and does not include fines or penalties as authorized by state or federal law." ORS 757.600(35) (emphasis added).

[3] "'Economic utility investment'" means all electric company investments, including plants and equipment *and contractual or other legal obligations,* properly dedicated to generation or conservation, that were prudent at the time the obligations were assumed but the full benefits of which are no longer available to consumers as a direct result of ORS 757.600 to 757.667, absent transition credits. 'Economic utility investment' does not include costs or expenses disallowed by the commission in a prudence review or other proceeding, to the extent of such disallowance, and does not include fines or penalties authorized and imposed under state or federal law." ORS 757.600(10) (emphasis added).

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Schedule 200. PacifiCorp Exhibit 103. PacifiCorp's cost-of-service rate, energy only, includes the cost of PacifiCorp's FPT transmission service. Attachment A, at 3, lines 2-4, and 15, lines 1-7.[4]

As the cost-of-service rate, energy only, is used in the transition adjustment calculation (*i.e.*, the proposed interim transition adjustment is calculated as the difference between the market price and the cost-of-service rate, energy only, adjusted for PacifiCorp system losses), PacifiCorp achieves full cost recovery for FPT service even when a customer chooses direct access.

It is contrary to law for PacifiCorp to recover FPT costs in a transition charge, and also recover the same costs through economic use of FPT service for the benefit of PacifiCorp's other customers or investors. Under a buy-sell agreement with an ESS, in which an ESS pays PacifiCorp the FTP transmission rate as part of the price for power purchased at PacifiCorp's border, the incremental revenue generated for this service should accrue to direct access customers who freed-up the FTP capacity for resale, thus generating a transition credit for these same customers. Buy-sell agreements will balance the interests of both direct access customers and cost of service customers. If the incremental revenue is not provided as a credit to direct access customers, PacifiCorp will double recover the cost of FPT transmission.

[4] The Commission may consider PacifiCorp's testimony in UE 147. *See, In re Nike, Inc. Securities Litigation, 181 F. Supp 2d 1160, 1165 (D Or., 2002)* ("The court may judicially notice facts from publicly available documents. *In re Silicon Graphics, Inc., Securities Litigation, 183 F. 3d at 986-87* (proper to consider SEC filings referenced in the Complaint)."

C. Transmission That Is Incremental To Pacificorp's FPT Contracts Should Not Be Valued Using "Ongoing Valuation", But As An Avoided Cost, Much Like The Credit For Avoided Losses In The Proposed Interim Transition Calculation

PacifiCorp's proposed interim transition calculation includes a credit for the avoided cost of losses on PacifiCorp's transmission system. In the same manner, when PacifiCorp requires incremental transmission to wheel power to its system to serve load, direct access customers can reduce PacifiCorp's need for such incremental capacity. This will enable PacifiCorp to avoid the cost of incremental transmission once FTP capacity has been fully utilized. As with the transition credit that represents the avoided cost of PacifiCorp's system losses in the proposed interim transition calculation, a transition credit should accrue to direct access customers to represent avoided wheeling to PacifiCorp's system.

D. There Is Not A Consensus That PacifiCorp Should Develop And File A Transition Adjustment Methodology That Is Based On GRID

Contrary to PacifiCorp's statements in its Opening Brief, EPCOR has not expressed an opinion on use of GRID for the fall 2005 enrollment window. PacifiCorp Opening Brief at 1, lines 13-15. EPCOR is focusing its efforts in this proceeding on the *interim* transition adjustment calculation and the issue of recognizing the value of avoided incremental transmission in the future (capacity that PacifiCorp will require in the future to serve its increasing system load, yet can avoid by customers choosing direct access). EPCOR's decision to not provide comments regarding use of GRID does not indicate that EPCOR concurs that GRID should be used to determine the PacifiCorp's longer term transition adjustment.

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V. PACIFICORP HAS QUOTED EPCOR OUT OF CONTEXT

As PacifiCorp states, EPCOR told FERC that "*Relative to the Oregon retail direct-access market, Mid-C is geographically the most proximate and relevant hub*". PacifiCorp's Opening Brief at 10, lines 8-14 (emphasis added). This statement, however, was made solely in the context of addressing PacifiCorp's then proposed Open Access Transmission Tariff Schedule 4, Energy Imbalance Service, **not** valuation for purposes of the Oregon transition adjustment.

PacifiCorp also points out that EPCOR testified that EPCOR: (i) generally relies on forward price curves at the Mid-Columbia hub to sell into the Oregon market; and (ii) uses Mid-Columbia hub as the basis for its modeling of the transition adjustment. The use of the Mid-Columbia hub by EPCOR in both cases is an obvious reflection of the fact that PacifiCorp's current transition calculation is based exclusively on Mid-Columbia hub pricing (as is PGE's transition adjustment, a market in which EPCOR serves load). It would not be rational for EPCOR to incorporate forward prices from PacifiCorp's other three system hubs — hubs that PacifiCorp's testimony characterizes as being priced "quite higher than the Mid-C" (Tr. at. 43, lines 4-5, Testimony of Apperson), with "different markets" with "different locations, different fundamentals driving those markets" – into a Transition Calculation that is based solely on Mid-Columbia pricing... Tr. at 43, lines 8-9, Testimony of Apperson.

VI. PACIFICORP ARGUES INCONSISTENT POSITIONS IN THIS PROCEEDING AND BEFORE FERC, AND WANTS THIS COMMISSION TO REACH AN OUTCOME INCONSISTENT WITH FERC'S CONCLUSIONS ABOUT "THE MARKET VALUE OF ENERGY THAT PACIFICORP COULD HAVE SOLD"

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PacifiCorp rehashes its claim that EPCOR took inconsistent positions before this Commission and the Federal Energy Regulatory Commission ("FERC"). PacifiCorp Opening Brief at 10, lines 8-14. EPCOR did no such thing. In fact, it is PacifiCorp that has taken inconsistent positions and it is PacifiCorp that is attempting to secure an outcome in this proceeding that is inconsistent with FERC's Order.

EPCOR has not taken a position on the subject of whether power freed up by direct access should be deemed to be marketed at the four market hubs instead of just the Mid-Columbia hub as proposed by PacifiCorp. Mr. Whittles testified that EPCOR has not studied the four-market hub methodology proposed by ICNU. EPCOR explained that PacifiCorp's provision of real-time Energy Imbalance Service to serve PacifiCorp's Oregon retail direct access customers is fundamentally different than valuing PacifiCorp's generation resources (or avoided purchases) across PacifiCorp's entire system spread across the west. EPCOR's Opening Brief at 23-24.

PacifiCorp wants this Commission to reach a decision that is the opposite of the decision it sought from FERC. Before FERC, PacifiCorp sought to optimize Energy Imbalance revenues from its Open Access Transmission Tariff customers by calculating the cost of Energy Imbalance Service at four hubs. On the other hand, before this Commission, PacifiCorp objects to the four-hub method which PacifiCorp states "can create as much as a 54 percent premium for direct access over cost of service in some months." PacifiCorp Opening Brief at 9, lines 25-26. Apparently, PacifiCorp does not see the irony in receiving a "premium" from its wholesale transmission customers (including Oregon retail direct access customers who are exposed to Energy Imbalance

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Service from PacifiCorp), while proposing to deny the same premium to its direct access customers.

On July 28, 2004, in *PacifiCorp*, FERC Docket No. ER04-439-002, FERC issued an Order accepting PacifiCorp's revisions to PacifiCorp's Open Access Transmission Tariff. In rejecting EPCOR's protest that the charge for Energy Imbalance Service should be based on the Mid-Columbia price, FERC stated that it had addressed the issue of the pricing methodology for Energy Imbalance Service in 2001. At that time, "the Commission found that the charges for Energy Imbalance Service are intended to represent '*the real cost of replacing the imbalances and is the lost opportunity cost of the market value of the energy that PacifiCorp could have sold*, if that energy had not otherwise been utilized to cover an imbalance.'" *Slip Opinion* at 3 (emphasis added). PacifiCorp asks this Commission to reach the precise opposite conclusion with respect to power freed-up by direct access, and for that reason, the Commission should require the four-hub approach proposed by ICNU.

VII. EPCOR IS NOT SEEKING A TRANSMISSION SUBSIDY THAT SHIFTS COSTS TO OTHERS CUSTOMERS, OR A TRANSITION CREDIT TO "COVER" ESS TRANSMISSION COSTS; EPCOR SEEKS AN ACCURATE, FAIR AND COMPREHENSIVE VALUATION FOR ALL DIRECT ACCESS CUSTOMERS

The transition adjustment calculation should fully and completely reflect the benefits and costs of PacifiCorp's operations. Direct access customers are entitled to a transition adjustment that includes the benefit of a credit for costs that PacifiCorp avoids as a result of direct access. EPCOR notes and supports the comments of Staff in these respects that "...partial pass-through of the benefits (of direct access), may create a barrier

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to direct access participation," and that "...a transition adjustment that passes through benefits that are less than PacifiCorp's actual benefits may be inconsistent with statutory requirements." (Staff Brief, p.2).

In this regard, it is thus imperative that the effect of direct access to reduce PacifiCorp's requirements for transmission service, whether for existing FPT capacity or in respect of incremental capacity required in the future, be properly accounted for as benefits and avoided costs in the transition adjustment calculation.

Including these transmission benefits in the transition adjustment calculation, as EPCOR proposes, would not be an arbitrary mechanism to "subsidize" direct access – as appears to be a concern of Staff [Staff Brief, p.3] – or to "cover ESS transmission costs to make direct access an economic choice..." – as asserted by PacifiCorp (PacifiCorp Brief, p. 9). Rather EPCOR's proposed methodology ensures fairness to direct access customers in respect of transmission benefits and avoided costs arising under direct access, and avoids the creation of barriers to direct access. EPCOR submits that the Commission should direct PacifiCorp to adopt EPCOR's proposed methodology for the calculation of the interim transition adjustment calculation.

VIII. THE REASON DIRECT ACCESS DOES NOT RESULT ENTIRELY IN AVOIDED PURCHASES IS DUE LARGELY TO PACIFICORP'S APPROACH

EPCOR agrees with ICNU that PacifiCorp's rolling 24-month resource acquisition strategy, combined with PacifiCorp's desire to balance its forward load/resource position without planning on any load electing direct access, is the reason that direct access does not result entirely in avoided purchases. EPCOR further agrees with ICNU that the single largest impact of direct access participation is avoided purchases, the proportion of which

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increase under low levels of direct access participation, and that the volume of avoided purchases may be even greater as Commission Staff states that GRID may overstate the actual levels of reduced generation. ICNU Opening Brief, pages 16-17.

IX. CONCLUSION

For the reasons described in this brief, EPCOR respectfully asks the Commission to order PacifiCorp to enter into buy-sell arrangements with ESSs, and to order that PacifiCorp's transition adjustment include a transition credit for PacifiCorp's cost of FPT service.

DATED this 13th day of August, 2004.

Respectfully submitted,

PRESTON GATES & ELLIS LLP

By

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CERTIFICATE OF SERVICE AND FILING

I hereby certify that on the date indicated below, I caused the above-entitled **REPLY BRIEF** to be filed via email and via facsimile with the:

Public Utility Commission of Oregon

On the same date, I sent the original and five copies via UPS Overnight. I also served a true, complete and correct copy of the above-mentioned document electronically, via facsimile and regular U.S. Mail on the following parties:

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DATED this 13th day of August, 2004.

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Case UE –
PPL Exhibit 500
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Mark T. Widmer

Net Power Costs

March 2003

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Mark Widmer, my business address is 825 N.E. Multnomah, Suite 800, Portland, Oregon 97232, and my present position is Manager, Regulation.

I. Qualifications

Q. Briefly describe your education and business experience.

A. I received an undergraduate degree in Business Administration from Oregon State University. I have worked for PacifiCorp since 1980 and have held various positions in the power supply and regulatory areas. I was promoted to my present position in March 2001.

Q. Please describe your current duties.

A. I am responsible for the coordination and preparation of net power cost data and related analyses used in retail price filings. In addition, I represent the Company on power resource and other various issues with intervenor and regulatory groups associated with the six state regulatory commissions that have jurisdiction over the Company's retail electric operations.

II. Summary of Testimony

Q. Will you please summarize your testimony?

A. I will present the results of the production cost model study for the 12-month period ending March 31, 2004. I will describe the Company's production cost model, the Generation and Regulation Initiatives Decision Tools (GRID) model, which is used to calculate net power costs. I will also provide information on how input data is normalized in GRID and the rationale for doing so.

III. Net Power Cost Results

Q. What are the results of the Company's normalized test year net power cost study?

A. The Company's normalized net power costs for the twelve-month period ending March 31, 2004 are approximately $611 million on a Total Company basis.

Q. How does this compare with the level currently in rates?

A. Test period net power costs are forecast to be approximately $22 million higher than the $589 million included in base rates from the Docket UE 134 settlement or $34 million lower if the amortization of the summer 2002 forward purchases is added to the base rate level. However, on an Oregon allocated basis, as shown in PPL Exhibit 601, page 5.1, net power costs in this filing are $171.9 million. $22.8 million lower than the level included in base rates.

Q. How does the Company's test period forecast compare to recent actual experience?

A. The Company's test period net power cost forecast is approximately $76 million lower that the $687 million the Company incurred for net power costs during the twelve-month period ending September 30, 2002. The majority of the difference is related to the high-priced summer 2002 forward purchases that occurred during the historical period and are being recovered through the settlement in Docket UE 134.

Q. Did the 1996-1998 vintage wholesale sales contracts that were a point of contention in prior cases carry into the test period?

A. No. They expired prior to the first month of the test period.

IV. Determination of Net Power Cost

Q. Please explain net power costs.

A. Net power costs are defined as the sum of fuel expenses, wholesale purchase expenses and wheeling expenses, less wholesale sales revenue.

Q. Were the proposed net power costs, which you have sponsored, developed in a manner consistent with the Company's UE 134 power cost filings?

A. Yes, with one minor exception. The Company's proposed net power costs were developed using the updated version 2.0 of the GRID model. Consistent with the commitments made in the UE 134 settlement, the Company made improvements in the user interface. The calculation logic is essentially the same. That is, internally the model is more efficient, but the results are the same.

Q. Please explain how the Company calculated net power costs.

A. The Company calculated net power costs on a normalized basis using the GRID model. The model simulates the operation of the power supply portion of the Company under a variety of stream flow conditions on an hourly basis. The results obtained from the various stream flow conditions were averaged and the appropriate cost data was applied to determine an expected net power cost under normal stream flow and weather conditions for the test period.

Q. Please explain how GRID estimates net power costs.

A. The development of expected net power costs begins with the selection of either a forecast or historic test period. In this case, the Company is using a forecast test year for the twelve-month period ending March 31, 2004. I have divided the description of the power cost model into three sections, which follow below:

1. The model used to calculate net power costs.
2. The model inputs.
3. The model output.

V. The GRID Model

Q. Please describe the GRID model.

A. As noted above, the GRID model is an hourly production dispatch model, which the Company uses to calculate net power costs. It is a server-based application that uses the following high-level technical architecture to calculate net power costs:

- An Oracle-based data repository for storage of all inputs
- A Java-based software engine for algorithm and optimization processing
- Outputs that are exportable in Excel readable format
- A web browser-based user interface

Based on requests by regulatory staffs and intervenors, the model has been modified to also run on stand-alone personal computers.

Q. Please describe the methodology employed to calculate net power costs in this docket.

A. Net power costs are calculated on an hourly basis using the GRID model. The general steps are as follows:

1. Determine the input information for the calculation, including retail load, wholesale contracts, market prices, thermal and hydro generation capability, fuel costs, transmission capability and expenses
2. The model calculates the following pre-dispatch information:

- Thermal availability.
- Thermal commitment based on market prices.
- Hydro shaping and dispatch.
- Optional energy takes of those firm contracts with flexible delivery terms.
- Energy take of those firm contracts with a fixed delivery schedule.
- Reserve requirement and allocation between hydro and thermal resources.

3. The model determines the following information in the Dispatch (optimization) process, based on pre-dispatched resources and contracts:
   - Optimal thermal generation levels, and fuel expenses
   - Expenses (revenues) of the firm purchase (sales) contracts
   - System balancing market purchases and sales necessary to balance and optimize the system and net power costs taking into account the constraints of the Company's system
   - Expenses for purchasing additional transmission capability
4. Model outputs are used to calculate net power costs on a Total Company basis, incorporating expenses (revenues) of purchase (sales) contracts that are independent of dispatched contracts, which are determined in step 3.

The main processors of the GRID model are steps 2 and 3.

Q. Please describe in general terms, the purposes of the Pre-dispatch and Dispatch processes.

A. Pre-dispatch focuses on inter-hour relationships and Dispatch focuses on hourly relationships.

Q. Please give an example of an inter-hour relationship.

A. GRID looks at each limited energy resource and determines the best use for the limited energy over a range of hours. A hydro unit with storage and a contract with a 70 percent maximum load factor are examples of limited energy resources.

Q. Please describe the Dispatch process.

A. The Dispatch process is a linear program (LP) optimization module. For each hour, it determines how the available thermal resources should be dispatched given load requirements, transmission constraints and market conditions, and whether market purchases should be made to balance the system. In addition, if market conditions allow, market purchases may be used to displace more expensive thermal generation. At the same time, market sales may be made either from excess resources or market purchases if it is economical to do so under market and transmission constraints.

Q. Does the Pre-dispatch process provide thermal availability and system energy requirements for the Dispatch process?

A. Yes. Pre-dispatch calculates the availability of thermal generation, dispatches hydro generation, schedules firm wholesale contracts, and determines the reserve requirement of the Company's system. I describe each of the calculations in more detail below.

VI. Generating resources in Pre-Dispatch

Q. Please describe how the GRID model determines thermal availability and commitment.

A. The Pre-dispatch process reads the input regarding thermal generation by unit, such as nameplate capacity, normalized outage and maintenance schedules, and calculates the available capacity of each unit for each hour. The model then determines the hourly commitment status of thermal units based on planned outage schedules, and a comparison of operating cost vs. market price if the unit is capable of cycling up and down in a short period of time. The commitment status of a unit indicates whether it is economical to bring that unit online in that particular hour. The availability of thermal units and their commitment status are used in the Dispatch process to determine how much may be generated each hour by each unit.

Q. How does the model shape and dispatch hydro generation?

A. In the Pre-dispatch process, the Company's available hydro generation from each non-run-of-river project is shaped and dispatched by hour within each month in order to maximize usage during peak load hours. The monthly shape of a non-run-of-river project is based on the hourly retail load and market prices in a month, and incorporates minimum and maximum flow for the project to account for environmental constraints. The dispatch of the generation is flat in all hours of the month for run-of-river projects. The hourly dispatched hydro generation is used in the Dispatch process to determine energy requirements for thermal generation and system balancing transactions.

VII. Wholesale contracts in Pre-Dispatch

Q. Does the model distinguish between short-term firm and long-term firm wholesale contracts in the Pre-dispatch process?

A. Yes. Short-term firm contracts are block energy transactions with standard terms and a term of one year or less in length. In contrast, many of the Company's long-term firm contracts have non-standard terms that provide different levels of flexibility. For modeling purposes, long-term firm contracts are categorized as one of the following eight archetypes based on contract terms:

- Energy Limited (shape to price or load): the energy take of these contracts have minimum and maximum load factors. The complexities can include shaping (hourly, annual), exchange agreements, and call/put optionality.
- Block Option: the energy take of these contracts is for a block of hours. For example, the Morgan Stanley contract is a daily call. If we call on it, we must take it for all sixteen heavy load hours of the day.
- Generator Flat: the energy take of these contracts is tied to specific generators and is the same in all hours, which takes into consideration plant down time. There is no optionality in these contracts.
- Generator Optional: the energy take of these contracts is also tied to specific generators but is dispatched as generators with flexibility. They can be either hydro or thermal generation.
- Flat: these contracts have a fixed energy take in all hours of a period.
- Complex: the determination of energy take of these contracts requires the load and resource balances of the third party.
- Contracted Reserves: these contracts do not take energy. They are contracts for the reserve calculation.

– No Energy: these contracts do not take energy. They are contracts for capturing fixed costs.

In the Pre-dispatch process, long-term firm purchase and sales contracts are dispatched per the specific algorithms designed for their archetype.

Q. Are there any exceptions regarding the procedures just discussed for dispatch of short-term firm or long-term firm contracts?

A. Yes. Whether a wholesale contract is identified as long-term firm or short-term firm is entirely based on the length of its term. Consistent with previous treatment, the Company identifies long-term firm contracts by name and groups short-term firm contracts by general delivery points. If a short-term firm contract has flexibility as described for long-term firm contracts, it will be dispatched using the appropriate archetype. Conversely, if a long-term firm contract is a transaction for standard block of energy, it will be dispatched the same way as standard short-term firm block transactions. Dispatched hourly contract energy takes are used in the Dispatch process to determine the energy requirements for thermal generation and system balancing transactions.

VIII. Reserve requirement in Pre-Dispatch

Q. Please describe the reserve requirement on Company's system.

A. The North American Electric Reliability Council (NERC) requires all companies with generation to carry operating reserves of 5 percent for operating hydro resources and 7 percent for operating thermal resources. A minimum of one-half of these reserves must be spinning. Spinning reserves must be on-line and responsive to an automated signal from the control area. It is limited to the unit's

10-minute ramp rate. NERC and WECC require companies with generation to carry spinning reserves to protect the WECC system from cascading loss of generation or transmission lines, uncontrolled separation and interruption of customer service. Non-spinning operating reserves must be available within a 10-minute period.

Q. How does the model implement the operating reserve requirement?

A. The model calculates operating reserve requirements (both spinning and non-spinning) for the Company's East and West control areas, plus regulating margin that is added to spinning reserve requirements. The total operating reserve requirement is 5 percent of dispatched hydro and 7 percent of committed available thermal resources for the hour, which includes both Company's owned resources and long-term firm purchase and sales contracts that contribute to the reserve requirement. Spinning reserve is one-half of the total reserve requirement plus regulating margin, which is the same in nature as the spinning reserve but used for following changes in retail load from one hour to the next.

Q. How does the model satisfy reserve requirements?

A. Reserves are held first on hydro then on thermal units on a descending variable cost basis. Spinning reserve is satisfied before the non-spinning requirement. For each control area, spinning reserve requirement is fulfilled using hydro resources and thermal units that are equipped with governor control. The remaining operating requirement is fulfilled using remaining hydro reserves and thermal units. To better utilize the reserve capability of the Company's West side hydro system, up to 175 MW of East side reserves can be held in the West control region, of which 100 MW is spinning and 75 MW is non-spinning. The allocated hourly reserve requirement to the generating units is used in the Dispatch process to determine energy available from the resources and the level of the system balancing market transactions.

Q. What is the impact of reserve requirement on resource generating capability?

A. There is no impact on the total hydro generation, since the amount of reserve allocated to hydro resources is based on the difference between maximum technical capability and the current hour dispatch level. However, if a thermal unit is designated to hold reserves, its hourly generation will be limited to no more than its capability minus the amount of reserves it is holding.

IX. Model Inputs

Q. Please explain the inputs that go into the model.

A. As mentioned above, inputs used in GRID include retail loads, thermal plant data, hydroelectric generation data, firm wholesale sales, firm wholesale purchases, firm wheeling expenses, system balancing wholesale sales and purchase market data, and transmission constraints.

Q. As part of this case, is the Company filing the inputs used to calculate net power costs?

A. Yes. The Company is including its model inputs in this filing. These inputs are part of the Company's GRID model, which is loaded on the PC hard drives that were provided as part of the Company's filing to Staff, CUB and ICNU.

Q. Please describe the retail load that is used in the model.

A. The retail load represents the hourly firm retail load that the Company is expected to serve within all of its jurisdictions for the twelve-month period ending March 31, 2004. The total company load is modeled based on the location of the load and transmission constraints between generation resources to load centers. The load forecast is presented by Mr. Davis.

Q. Please describe the thermal plant inputs.

A. The amount of energy available from each thermal unit and the unit cost of the energy are needed to calculate net power costs. To determine the amount of energy available, the Company averages for each unit, four years of historical outage rates and maintenance adjusted to remove extraordinary outages. The unit cost of energy for each unit is determined by using a four-year average of historical burn rate data. By using four-year averages for outages, maintenance and burn rate data, annual fluctuations in unit operation and performance are smoothed. The four-year period used by the Company for this filing is 48 months ending September 2002. Other thermal plant data includes unit capacity, minimum generation level, minimum up and minimum down time, heat rate, fuel cost, and startup cost. The Company's use of a four-year average is consistent with the previously authorized treatment in Oregon and Utah.

Q. Are there any exceptions to the 48 month average data mention above?

A. Yes. Because the Company is recovering the cost of the catastrophic Hunter unit 1 outage through the treatment adopted in UM 995, the Company has excluded that outage from its 48-month outage calculation.

Q. Please describe the hydroclectric generation input data.

A. Fifty years of monthly available hydroelectric generation for Company-owned hydro plants in the Northwest and Mid-Columbia purchased resources are input into the model. The hydro data that is programmed into the production cost model is from the Bonneville Power Administration (BPA) Hydro Regulation computer program (Hydro Regulation). Data from Hydro Regulation is based on actual stream flows for the period August 1928 through July 1978. Hydro Regulation simulates the hydroelectric generation at each facility on the major rivers in the Pacific Northwest based on inputs provided by each member of the Northwest Power Pool, Idaho Power Company, and the Assured Operating Plan of the Canadian Utilities. The purpose of Hydro Regulation is to maximize the firm energy capability of the Pacific Northwest hydroelectric system. It is based on hydroelectric plant efficiencies, storage capabilities and requirements, minimum flow requirements (including fish requirements), regional loads and resources, and non-power operating constraints. The data are grouped by generation projects of each river system.

Q. Is the input of hydro generation located outside of the Northwest modeled in the same manner as the Pacific Northwest hydro generation?

A. No. The input of hydro generation located in Utah and Southeast Idaho is calculated as the actual average monthly hydroelectric generation for the years 1974 through September 2002. A shorter time frame is used for the Utah and Southeast Idaho hydro resources than the Company's other hydro resources because their relative size is small, there is no overall area model analogous to the

Hydro Regulation model in the Northwest and there is a lack of reliable data for the earlier years.

Q. Does the Company use other hydro generation inputs?

A. Yes. The Company also uses maximum and minimum capacities of the projects, must-run level, and monthly shapes of the available energy.

Q. Are the hydro-related inputs calculated in the same manner as in the Company's historic filings?

A. Yes.

Q. Please describe the input data for firm wholesale sales and purchases.

A. The data for firm wholesale sales and purchases are based on contracts to which the Company is a party. Each contract specifies the basis of quantity and price. The contract may specify an exact quantity of capacity and energy or a range bounded by a maximum and minimum amount, or it may be based on the actual operation of a specific facility. Prices may also be specifically stated, may refer to a rate schedule, a market index such as California Oregon Border (COB), Mid Columbia (Mid C) or Palo Verde (PV), or may be based on some type of formula. The long-term firm contracts are modeled individually, and the short-term firm contracts are grouped based on general delivery points. Again, the use of actual contract terms as the basis for wholesale sales and purchases inputs is consistent with the Company's past practice, with one exception. The contracts with flexible delivery terms are now dispatched against the hourly market prices so that they are optimized.

Q. Please describe the input data for wheeling expenses and transmission capability.

A. The data for firm wheeling are based on contracts to which the Company is a party. The firm transmission rights modeled in GRID are developed from the Company's OASIS for summer/winter postings. The limited additional transmission rights that the Company may have access to are based on the experience of the Company's Commercial and Trading Department.

Q. Please describe the system balancing wholesale sales and purchase input assumptions.

A. The GRID model uses three wholesale markets to balance and optimize the system. The three markets are at Mid C, COB and Desert Southwest (DSW), where the model makes both system balancing sales and purchases if it is economical to do so under constraints. The input data regarding wholesale markets include market prices and sizes.

Q. What market prices are used in the net power cost calculation?

A. The market prices for the system balancing wholesale sales and purchases at Mid C, COB and DSW are based on Company's monthly forward price curves shaped into hourly prices. The market price hourly scalars are developed by the Company's Commercial and Trading Department based on historical hourly data since April 1996. Separate scalars are developed for on-peak and off-peak periods and for different market hubs to correspond to the categories of the monthly forward prices. Before the determination of the scalar, the historical hourly data are adjusted to synchronize the weekdays, weekends and holidays, and to remove extreme high and low historical prices. As such, the scalars represent the expected relative hourly price to the price in a month. The hourly prices for the test period are then calculated as the product of the scalar for the hour and the corresponding monthly forward price.

X. Normalization

Q. Please explain what is meant by normalization and how it applies to the production cost model for forecast test years.

A. For forecast test years, normalization of input data for the production cost model is primarily limited to hydro and thermal data. The availability of energy from Company-owned and purchased hydroelectric generation is normalized by running the production cost model for each of the 50 different water years identified in the Hydro Regulation. The resultant 50 sets of thermal generation, non-firm sales and purchases, and hydroelectric generation are then averaged using a weighting method which accounts for 115 years of stream flow data as measured on the Columbia River at The Dalles. As previously explained, normalized thermal availability is based on a four-year average adjusted for the Hunter 1 outage.

Q. You stated that hydroelectric generation is normalized by using historical water data. Please explain why the regulatory commissions and the utilities of the Pacific Northwest have adopted the use of production cost studies that employ historical water conditions for making these normalization adjustments.

A. In any hydroelectric-oriented utility system, water supply is one of the major variables affecting power supply. The operation of the thermal electric resources both within and outside the Pacific Northwest are directly affected by water conditions within the Pacific Northwest. During periods when the stream flows are at their lowest, it is necessary for utilities to operate their thermal electric resources at a higher level or purchase more from the market, thereby experiencing relatively high operating expenses. Conversely, under conditions of high stream flows, excess hydroelectric production may be used to reduce generation at the more expensive thermal electric plants, which in turn results in lower operating expenses for some utilities and an increase in the revenues of other utilities, or any combination thereof. No one water condition can be used to simulate all the variables that are met under normal operating conditions. Utilities and regulatory commissions, therefore, have adopted production cost analysis that simulates the operation of the entire system using historical water conditions, as being representative of what can reasonably be expected to occur.

XI. Model Outputs

Q. What variables are calculated from the production cost study?

A. These variables are:

- Dispatch of firm wholesale sales and purchase contracts;
- Dispatch of hydroelectric generation;
- Reserve requirement, both spinning and non-spinning;
- Allocation of reserve requirement to generating units;
- The amount of thermal generation required; and
- System balancing wholesale sales and purchases at three markets.

Q. What reports does the study produce using the GRID model?

A. The major output from the GRID model is the Net Power Cost report. Interim data that can be exported for more detailed analyses is also available, whose format can be hourly, daily, weekly, monthly, annually and by heavy load hours and light load hours.

Q. Do you believe that the GRID model appropriately reflects the Company's operating relationship in the environment in which it functions?

A. Yes. The GRID model appropriately simulates the operation of the Company's system over a variety of streamflow conditions, taking into account system operating constraints and requirements.

Q. Did the Company make any margin adjustments for short-term wholesale transactions similar to those proposed by the Oregon Commission Staff in prior cases?

A. No. The Company does not believe the short-term margin adjustments previously proposed by Staff, which were based on historical information, are appropriate. Net power costs are included in rates on a normalized basis, including short-term firm transactions which capture the value of the Company's system. The margins OPUC Staff has historically suggested in question are not certain by any means and therefore should be normalized like other items, which cause unpredictable variations in net power costs such as variations in temperature and hydro conditions.

Q. Does the Company's geographically dispersed transmission system and the ability to flex its system always result in positive short-term margins?

A. No. The Company's system allows it to take advantage of the market if opportunities present themselves, it does not guarantee that the Company will generate short-term margins at all times. Historical short-term margins vary to a great degree from month to month. During the last 12-month period monthly margins varied from (1.91) per MWh to 4.85 per MWh.

Q. Please explain why Staff's suggested short-term margins are not certain.

A. Short-term margins are not certain because they are related to a variety of factors that can affect the wholesale market and the Company's ability to take advantage of that market. Those factors include temperature variations, snow pack and hydro conditions, market prices and volatility, gas prices and volatility, the extent and timing of thermal outages, transmission availability and transmission constraints that occur during actual results. In addition, there is no guarantee that prior conditions will lead to positive margins or will occur from year to year to the same degree or even occur. That is why net power costs included in base rates are developed based on normal temperature and hydro conditions. For these reasons, the Company believes the type of margin adjustment previously proposed by Staff is not appropriate for setting base rates.

Q. If Staff's suggested short-term margins are not recoverable through base rates, is there a method whereby they could be captured when and if they occur?

A. Yes. They could be captured through a power cost adjustment mechanism, which would fairly capture all variances that cause power costs to fluctuate, both up and down. A power cost adjustment mechanism would provide a balanced approach for both customers and the Company to share in all deviations from normalized net power costs. However, it should be noted that the Company is not recommending a power cost adjustment mechanism at this time.

Q. Did the Company input additional revenue for the Sacramento Municipal Utility District (SMUD) long-term firm contract?

A. Yes. Revenue was imputed at a rate of $37 per MWh consistent with the treatment adopted for the Company's Utah and Wyoming jurisdictions.

Q. Please describe PPL Exhibit 501.

A. PPL Exhibit 501 is a schedule of the Company's major sources of energy supply by major source of supply, expressed in average megawatts, owned and contracted for by the Company to meet system load requirements, for the12-month test period ending March 31, 2004. The total shown on line 11 represents the total normalized usage of resources during the test period to serve system load. Line 12 consists of wholesale sales made to neighboring utilities within the Pacific Northwest, the Pacific Southwest, and the Desert Southwest as calculated from the production cost model study. Line 13 represents the Company's System Load net of special sales.

Q. Please describe PPL Exhibit 502.

A. PPL Exhibit 502 lists the major sources of normalized peak generation capability for the Company's winter and summer peak loads and the Company's energy load for the 12-month test period ending March 31, 2004.

Q. Does this conclude your direct testimony?

A. Yes.