EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: DAVID E. MILLS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-06____ Docket No. UG-06____

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
DAVID E. MILLS
ON BEHALF OF PUGET SOUND ENERGY, INC.

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VERSION

FEBRUARY 15, 2006

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy, Inc.

A. My name is David E. Mills. My business address is 10885 NE Fourth Street Bellevue, WA 98004. I am the Director, Power & Gas Supply Operations for Puget Sound Energy, Inc. ("PSE" or "the Company").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(DEM-2).

Q. What are your duties as Director, Power & Gas Supply Operations for PSE?

A. My responsibilities include oversight of the Company's Power Supply Operations and Gas Supply Operations Departments, including the following: (i) managing all PSE short-term (intra-month) and medium-term (up to two years) wholesale power and natural gas portfolios,[1] and (ii) working with the Company's Energy Resources department to plan for long-term hedging requirements. My responsibilities overlap with those of Mr. Salman Aladin in that both Mr. Aladin and I are charged with developing strategies to address risks related to PSE's electric and gas portfolios. While Mr. Aladin also focuses on analysis and modeling related to such risks, my focus tends to be more the operational and implementation side of portfolio risk management. In other words, I focus on the wholesale energy market transactions that the Company enters into to implement its hedging strategies and policies.

Q. What is the nature of your testimony in this proceeding?

A. Mr. Aladin describes in his direct testimony, Exhibit No. ___(SA-1CT), the volatility and risk of the Company's electric and natural gas portfolios. My testimony focuses on the structures and policies the Company has in place to manage these risks and the manner in which these policies are implemented. Among other things, I describe the robust hedging program that the Company has in place for both its gas and electric portfolios that is based on sound analyses and is reexamined and adjusted, as needed, in response to updated information. In short, the Company is working hard to reduce energy costs associated with its

[1] These "portfolios" consist of resources available to PSE to serve its customers. The electric portfolio includes generation facilities, purchase power and transmission capacity. The gas portfolio includes gas supply, storage and pipeline transportation capacity. For a more detailed discussion of PSE's portfolios, please see the prefiled direct testimony of Mr. Eric M. Markell, Exhibit No. ___(EMM-1HCT).

wholesale market purchases of power and natural gas.

I also explain that the Company's current hedging strategies have virtually exhausted the open credit that is available to the Company from wholesale energy market counterparties. I describe PSE's proposal in this case to establish a separate credit line dedicated to supporting its wholesale energy market transactions and to pass the costs of this credit facility through to PSE's customers in the same manner as other power and gas commodity costs. The Company's proposal would permit PSE to undertake even more of the good hedging work it is already doing at a relatively small additional cost.

My testimony then presents the Company's projection of rate year power costs for this proceeding. I explain how key assumptions used in projecting those costs are consistent with the methodologies approved by the Commission in the Company's 2004 general rate case, Docket No. UG-040640 et al., and implemented in the Company's last Power Cost Only Rate Case, Docket No. UE-050870 (the "2005 PCORC").

I also compare the projected rate year power costs in this proceeding to the projected rate year power costs for the 2005 PCORC. Altogether, PSE's projected rate year net power costs for this case are $965.5 million, which is approximately $90.5 million – or 10.3% – higher than what is presently reflected in PSE's PCA Power Cost Baseline Rate as established in the 2005 PCORC.

II. PSE'S MANAGEMENT OF POWER AND GAS COST RISKS

A. PSE's Risk Management Systems and Policies

Q. How does the Company manage the volatility of power and gas costs?

A. The Company has in place organizational structures, policies and overarching strategies to provide oversight and control of energy portfolio management activities, many of which must be undertaken on an hourly and daily basis by the experienced energy traders employed by PSE. The Company also utilizes modeling tools that assist in projecting whether its power and gas portfolios will be surplus or deficit gas or power in future months. The Company uses these tools to develop and implement hedging strategies to reduce the cost risks associated with portfolio volatility.

1. PSE Has Organizational Structures, Policies and Strategies in Place to Manage Electric and Natural Gas Portfolio Risks

Q. What organizational structures does the Company have in place with respect to portfolio risk management?

A. PSE's Energy Portfolio Management Department – composed of energy market analysts, quantitative analysts and other professionals – is responsible for identifying, quantifying, monitoring and reporting on risk factors. This Department also develops and recommends risk management strategies for the Company. The Energy Portfolio Management Department includes the Power

Supply Operations and Gas Supply Operations groups, which implement the Company's medium-term risk management strategies and manage PSE's medium-term portfolios.

The Energy Risk Control and Credit Risk Management groups provide risk control oversight. These two areas provide mid-office support and risk controls to the transaction process. Since August 2005, these areas have been led by a newly created senior management role, Vice President of Risk Management and Strategic Planning, acting as the Company risk officer.

PSE's Energy Management Committee – composed of senior PSE officers – oversees the activities performed by the Energy Portfolio Management Department and the Energy Resources groups. The Energy Management Committee provides policy-level and strategic direction on a regular basis. In addition, the Energy Management Committee regularly reviews position reports, sets risk exposure limits, approves policy and procedures, reviews proposed risk management strategies and approves strategies for implementation by PSE's staff.

In addition, the Company's Board of Directors provides executive oversight of these areas through its Finance and Budget Committee.

Q. Please explain why the Company established the Energy Management Committee?

A. The Energy Management Committee ("EMC") is the combined committee of the former Risk Management Committee and the Energy Resources Committee. The EMC is responsible for providing oversight and direction on all portfolio risk issues in addition to approving long-term resource contracts and acquisitions. A copy of the EMC Charter is attached as Exhibit No. ___(DEM-3).

Q. Does the Company have the same policies and overarching strategies with respect to its electric and gas portfolios?

A. No, PSE's management of its electric portfolio for electric customers (including the natural gas PSE acquires to generate electricity) is not the same as its management of its natural gas portfolio for gas customers (often called the "Core Gas" portfolio). PSE actively manages and hedges both portfolios, but does not always employ the same strategies. This is because management of the electric portfolio involves complexities not present in the Core Gas portfolio. The electric portfolio has complexities such as the relationship between wholesale market prices for power and the price of natural gas used to generate power. In addition, the extent of water available to generate power and alternatives available to the Company to generate, purchase or sell power result in additional risks and opportunities in the power portfolio.

a. PSE's Core Gas Portfolio Hedging Strategy

Q. Please describe the Company's policies and overarching risk management strategies with respect to its Core Gas portfolio.

A. The structure of the Core Gas portfolio hedging strategy can best be described as programmatic, with some discretion. It is a two-dimensional matrix, where both the time until delivery and required hedged volumes establish thresholds for executing wholesale gas market transactions. However, there is an additional price component to this matrix that accelerates hedging if prices fall to a certain level, referred to as the Threshold Price Level. The Threshold Price Level is derived by examining fundamental industry factors and modeling. Essentially, this price represents a "floor" where PSE feels comfortable accelerating its hedging because the price is approaching the marginal price of the highest cost resource, such as [redacted].

Q. Please describe the programmatic and discretionary aspects of the Core Gas hedging matrix.

A. The hedging timeframe, or horizon, for the Core Gas portfolio is [redacted] months, which encompasses at least [redacted]: November through March (winter) and April through October (summer). The strategy mandates that a certain percentage of the portfolio be hedged [redacted]. These volumetric hedge targets are spaced [redacted] apart, which allows PSE staff some flexibility as to when to execute the hedges. Execution timing is based on both fundamental and technical analysis performed by experienced traders. Hedge levels [redacted] and the strategy mandates that [redacted] percent of the [redacted] period. Specifically, the Core Gas Portfolio should have at least [redacted] MMBtu/day hedged going into the [redacted], and at least [redacted] MMBtu/day hedged going into the [redacted], both subject to credit availability. *See* Exhibit No. ___(DEM-4C).

Q. When did the Company develop its Core Gas hedging matrix?

A. The Company developed this approach to hedging the Core Gas portfolio in the summer of 2004. Prior to August 2004, when the current matrix was approved by the Risk Management Committee, Core Gas was hedged using a dollar cost averaging strategy that had fundamental price levels built into it. As prices increased, less volumes would be hedged; as prices decreased, more volumes would be hedged. The reason for this approach was that, historically, natural gas prices had remained very stable (excluding the anomaly of the "Western Energy Crisis"). If prices rose sharply, it was assumed that this was a short lived event and that prices would revert to the mean and fall back to historic levels. However, as gas prices and volatility continued to increase, staff realized that the growing price uncertainty required a change in the hedging methodology.

b. PSE's Electric Portfolio Hedging Strategy

Q. Please describe the Company's policies and overarching risk management strategies with respect to its Electric portfolio.

A. The Energy Management Committee has approved a programmatic hedging plan (called the "Rolling [redacted] Month Hedging Plan") that the Energy Portfolio Management staff follows to systematically reduce the Company's net power (including natural gas for generation) portfolio exposure beginning [redacted] months in advance of the month in which the power will be needed to serve PSE's load. Generally, the Plan requires Energy Portfolio Management staff to reduce PSE's net electric portfolio exposure each month such that the net exposure by the end of each month falls within the range of exposure – stated in dollars -- that is permitted in the plan.

On or before [redacted] months ahead of delivery, the bulk of the hedging strategies and transactions have been made per this programmatic plan. This is why the plan is called the "Rolling [redacted] Month Hedging Plan" even though it begins [redacted] months ahead of the time of delivery – it is implemented over the time period from [redacted] to [redacted] months ahead of delivery.

Q. Is the "Rolling [redacted] Month Hedging Plan" entirely programmatic?

A. No, like the Core Gas hedging matrix, the "Rolling [redacted] Month Hedging Plan" incorporates elements of discretion. Energy Portfolio Management staff have discretion as to how to accomplish the required reduction in exposure during the course of each month. For example, they may decide whether to purchase or sell power or gas for power, how much to purchase or sell, and the time(s) during the month to complete such transactions. They also have discretion to decide whether to push toward the maximum or minimum monthly dollar limits each month, or somewhere in between. The manner in which the Plan is implemented is described in greater detail below.

Energy Portfolio Management staff may also recommend departures from this Plan, pursuant to market fundamentals or trends, but execution of any such departures from previously-approved strategies is subject to Energy Management Committee approval.

Q. How did the Company develop the electric hedging strategy described above?

A. PSE initially wished to develop more programmatic hedging strategies because, while one can make projections regarding future market movements, one can never know at the time of a hedging transaction how the future will actually unfold. Thus, the Company saw a benefit in avoiding hedging strategies that are overly reliant on discretionary market timing.

Toward this end, PSE implemented a "dollar cost averaging" strategy for its electric portfolio in 2002, just as it did with respect to its Core Gas hedging. The dollar-cost averaging strategy required Energy Portfolio Management staff to purchase a specific volume of gas or power each month, in order to work gradually toward meeting the Company's projected need for gas or power during future months.

Q. Did the Company change this initial dollar-cost averaging strategy?

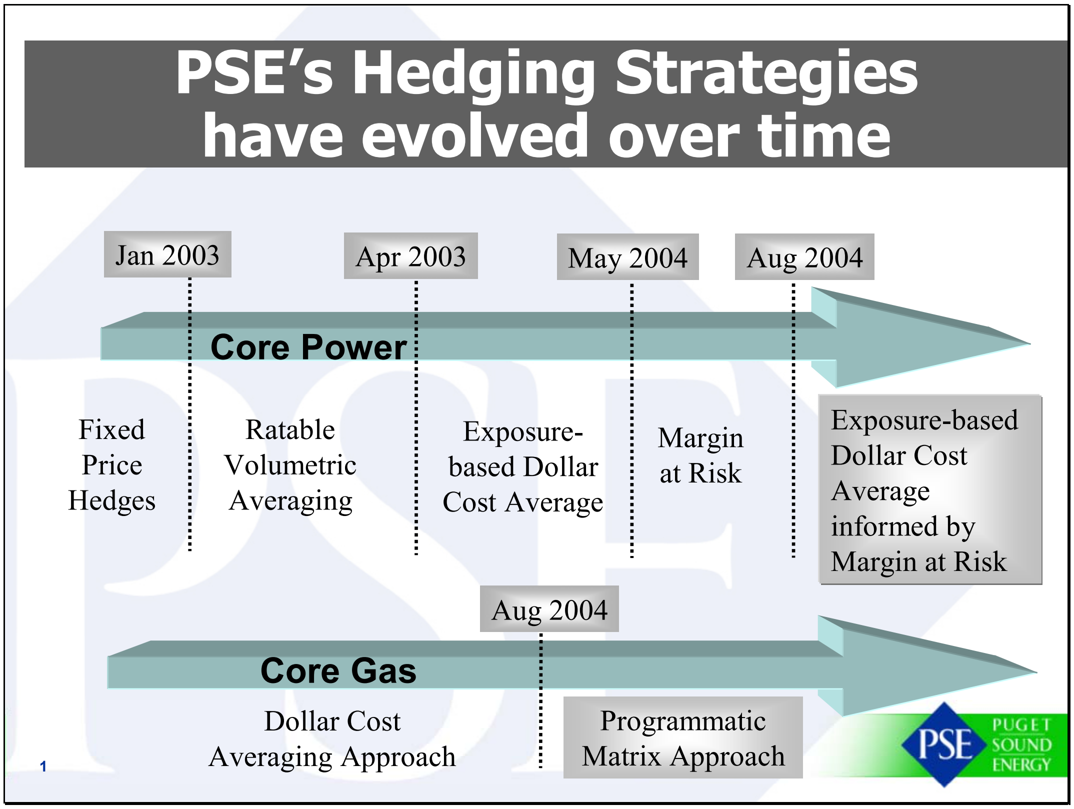
A. Yes, by spring 2003, the Risk Management Committee approved expansion of this concept to an "Exposure-based Dollar Cost Averaging." This refinement moved the Company from defining a specific commodity and volume to be hedged every month to a dollar amount of risk reduction to be accomplished every month. Under this approach, the Risk Management Committee would approve a dollar figure of risk to be reduced, and PSE staff would determine whether it was better to hedge gas or power. As markets went up or down, the dollar amount would allow for greater or less volumetric purchases.

In May 2004 (during PCA Period 2), the Company began to employ a metric called Margin at Risk, to measure risk reduction as a result of incremental hedging. *See* Exhibit No. ___(DEM-5C). PSE has incorporated the Margin at Risk concept into the evaluation process for hedge strategies to measure risk reduction for various commodity alternatives. A series of hedge strategies, or transaction types, are run through the portfolio risk system, providing a table of how much risk reduction is gained, by month and by strategy. The Margin at Risk concept assists with deciding how to allocate dollars across commodities in a credit-constrained environment.

In July 2004, the Risk Management Committee approved a continuation of a dollar cost averaging strategy informed by Margin at Risk. However, the Committee directed that PSE staff monitor and more actively address the exposure associated with PSE's power portfolio position [redacted] months ahead of the time the power would be needed. This Rolling [redacted] Month Hedging Plan, the current power portfolio hedging strategy described in the beginning of this section of my testimony, requires Energy Portfolio Management staff to more actively manage the next rolling [redacted] months beyond the period [redacted] months ahead of delivery in which they were already engaged in very active, ongoing hedging and balancing transactions. This hedging plan increased staff's ability to react to position changes as a result of stream-flow variations, forced thermal plant outages and changing market conditions. *See* Exhibit No. ___(DEM-6C).

Q. Please summarize how the Company's hedging strategies have evolved over time.

A. The following flowchart illustrates these changes:



2. PSE Uses Sophisticated Modeling Tools and Extensive Information to Manage Its Portfolio and Implement Risk Management Strategies

Q. How does PSE integrate hedging activities into its Core Gas strategies?

A. PSE's Core Gas risk system models the estimated potential variability of future prices using a hundred price scenarios. This risk system permits PSE to model scenarios of prices and storage activity versus load requirements to represent future projected Core Gas portfolio needs. For example, the hundred price scenarios the risk system models help determine the Threshold Price Level described above, where PSE feels comfortable accelerating its hedging under the matrix. Specifically, PSE uses the lowest quartile (25 lowest priced natural gas scenarios) in the risk system to develop the Threshold Price Level.

Q. Are there other examples of how the Company's risk system modeling informs its discretionary actions under the Core Gas hedging matrix?

A. Yes. The Company's storage capacity at Jackson Prairie and Clay Basin, nearly [redacted] Bcf ([redacted] Dth), can have a large influence on the portfolio's position. The Company's model adjusts storage injections and withdrawals based upon the shape of forward price curves. The risk system also values these storage transactions. Based on this information, PSE staff may decide to release storage capacity to a third party, if that party is willing to pay more for the storage than what PSE staff thinks the Company can make by managing it internally.

Q. How does PSE integrate hedging activities into its provision of electric power to customers?

A. PSE's risk system employs production cost modeling techniques to estimate future demand for on- and off-peak power and natural gas for PSE's fleet of gas-fired power plants. This risk system permits PSE to model scenarios of power prices, hydro conditions, load projections, generating and contracted resources and other inputs as required, to represent future projected portfolio needs.

Q. Please describe further what the electric risk system does.

A. To model a variety of scenarios regarding PSE's gas-fired generation, the risk system takes into account each plant's individual operating characteristics which include unit efficiency, start-up costs, variable operating costs, minimum run times, planned and unplanned outages, availability, etc. The risk system performs simulations of different market conditions and random outages in order to develop an estimate of how much gas is required and how much power will be produced. The plants are modeled on an hourly basis and the information is aggregated into daily and monthly time frames for purposes of developing a forward-looking position. In modeling whether the portfolio is long or short gas or power, the risk system incorporates information about hedges that PSE has already executed.

The risk system incorporates the inter-relationship between gas and power prices in developing its probabilistic gas and power positions. In different market scenarios, PSE would have different gas or power requirements, the reason is twofold. First, the plants have different operating efficiencies (known as "heat rates") and become economic to dispatch at different price differentials between power and gas. Second, the forward market prices for power and gas change frequently and the price relationship between power and gas, known as the "implied market heat rate," changes as well. At certain implied market heat rates, PSE will expect to run each plant at an expected rate, and the expected plant gas requirements can be calculated. But if market conditions change, PSE will expect to adjust its gas and power purchases or sales in order to serve load with its most economic resource. For example, it may become more economic to purchase power than to purchase gas to generate the power PSE needs to serve its load. If this were to occur at a time when PSE's portfolio had been balanced prior to the time the implied market heat rate changed, then PSE would buy market power and sell the contracted gas into the open market in order to rebalance the portfolio under the new conditions.

Q. Please describe the output that the electric portfolio risk system produces.

A. The risk system generates a probabilistic volumetric position report for on-peak power, off-peak power, and gas for power, comprised of 100 scenarios. The position report shows, for each of the months following the date of the report, the resource types in PSE's power position grouped by Short-term Purchase and Sale transactions, Long-term contracts, Frederickson 1, Tenaska and Encogen, Combustion Turbines ("CTs"), NUGs/QFs, Coal Plants, Wind and Hydro (both PSE owned and Mid-Columbia ("Mid-C") contracts). The gas-fired generation is therefore categorized by heat rate efficiency of the facilities. The Fredonia, Fredrickson, and Whitehorn CTs are grouped together because of their similar heat rate conversions. The position of the Company's newer Frederickson 1 plant is shown separately from the others because of its lower heat rate.

Based on this probabilistic volumetric position for each month, the risk system also generates a report showing the potential net cost exposure associated with the "open" positions (defined as any net surplus or deficit amount). An example of such a report is provided as Exhibit No. ___(DEM-7C).

Q. How does PSE use the electric portfolio risk system to help make hedging decisions?

A. Once PSE's aggregated energy position and net exposure are defined for a particular period, the Energy Portfolio Management staff evaluate and develop risk management strategy proposals and/or execute transactions around the purchase or sale of gas or power, as appropriate, to move toward a balanced position and reduce the exposure. Execution entails entering into specific transactions with approved counterparties, using approved instruments, executed master agreements and available credit.

Q. How is the risk system used to implement the Rolling [redacted] Month Hedging Plan described above?

A. As described above, the Plan is set up to systematically reduce the total net exposure, for each month of the [redacted] months beyond the next [redacted] month timeframe, within maximum and minimum limits on the amount of hedging that can or must be done each month, so that the total net exposure for a month will fall within small bands consistent with the limits in the procedures document. The net exposure for each month is generated out of the risk system data.

Q. Does Energy Portfolio Management staff implement the Rolling [redacted] Month Hedging Plan using only the net exposure information?

A. No. The net exposure information drives transactions only to the point of showing whether PSE's exposure is within the maximum and minimum monthly limits of the Plan. Energy Portfolio Management staff must then make use of market information and information regarding factors that impact the wholesale electric and gas markets to decide whether to press toward the maximum or minimum monthly limits, or somewhere in between. They also have discretion to decide when and how, within a month, to execute transactions sufficient to maintain the net exposure within the maximum and minimum limits.

Q. How does the Energy Portfolio Management staff develop a view regarding how to exercise such discretion?

A. The Energy Portfolio Management Department utilizes a wide set of tools and sources of information to help them make informed decisions about dispatching plants, purchasing fuel, and executing hedges approved by the Energy Management Committee. They also hold weekly strategy meetings so that the team can review operational events, discuss market trends, and review new supply/demand information. Within this context, they work together to understand the exposures in the portfolio and discuss where hedging priorities occur. Underlying all this teamwork is an Energy Portfolio Management staff with years of experience in energy trading, optimization and risk management.

Q. What types of information does the Energy Portfolio Management staff consider?

A. The Energy Portfolio Management Department collects a wide range of data to monitor supply/demand factors which include but are not limited to: weather trends; macro economic factors; crude oil markets, gas storage inventories across the United States, Canada and in the western United States; hydro run-off forecasts, reservoir storage, precipitation and snowpack; and more. Additionally PSE staff review forecasts of price and supply/demand fundamentals, such as trading firm newsletters and consulting service forecasts.

The Energy Portfolio Management staff also receive real-time information from a variety of sources which include email newsletters from industry publishers such as McGraw Hill (Gas Daily, Megawatt Daily), Bloomberg (live news and market data), Telerate, Intercontinental Exchange (live price data), broker lines that act as PA systems where current transactions are communicated though a speaker system, and other tools. The Energy Portfolio Management group also has live data coming from the systems operations staff so they can view real-time load data and real-time generation dispatch.

In addition to using such information and processes to implement the Rolling [redacted] Month Hedging Plan, the Energy Portfolio Management group also uses such information to develop recommendations to the Energy Management Committee regarding potential changes to the Company's overarching hedging strategies or to recommend transactions that do not fall within those strategies.

Q. Does the Company use any other tools to manage its energy portfolio?

A. Yes. The Company also uses a counterparty credit risk management system to assist the Credit Risk Management group and Energy Portfolio Management staff in evaluating potential transactions with respect to credit issues. With this tool, staff can review data including: Moody's and S&P rating of the entity; applicable information about the parent of the entity; amount of parental guarantee extended to PSE, if applicable; the entity's amounts payable and receivable; the aggregate mark to market exposure of all open forward transactions with the entity (the dollar value of the difference between the original contract price and current market price); the credit limit assigned to the entity; the existence of netting terms; and FAS 149 designation for accounting purposes. This information is gathered and calculated daily.

Furthermore, the trader can model what impact an incremental trade could have with a specific counterparty. The counterparty credit risk management system models the impact on the credit exposure of the Company and the counterparty of the incremental trade itself, as well as the impact that would result if the market moved significantly away from the price at which the deal is struck. If a significant market move would cause the credit exposure to exceed the amount allowed with that counterparty, the system would indicate that the trade should not be performed with that counterparty. In that case, the trader would seek out a different counterparty for the transaction.

3. The Company Continues to Address Long-Term Hedging Issues

Q. Has the Company addressed long-term hedging issues in addition to the short- and medium-term strategies described above?

A. Yes. These efforts have taken place on a number of fronts, including: analyses conducted for the Company's 2005 Least Cost Plan (filed with the Commission on May 2, 2005); building upon PSE's modeling capabilities; surveying customer preferences with respect to price volatility and hedging costs; assessing the amount of credit available to PSE to engage in longer-term hedging; and engaging in long-term market fundamental analysis.

Q. What is entailed in the modeling work?

A. PSE is in the process of capitalizing on the strengths of two models: AURORA and the risk system (currently KW3000). The Company is deploying both AURORA and the risk system to run risk analysis using both gas and power forward market price inputs and to develop risk exposure metrics in the long-term portfolio similar to those that are already in place for the short- and medium-term portfolio.

Q. What work has PSE done in the area of fundamental market analysis?

A. For the last several years, the industry as a whole has anticipated that the recent rise in natural gas prices would cause an increase in production and a reduction of consumption and that new Liquified Natural Gas facilities and the delivery of Alaska and McKenzie Delta gas via pipeline projects would reduce prices as early as 2007-2008 for Liquified Natural Gas, and as early as 2009 for Arctic gas. PSE has been investigating this "worldview" as part of its analysis regarding whether to seek to engage in longer-term hedging of gas supply. PSE has continued to gather a great deal of information from external sources about future market developments and rising global demand from energy hungry developing countries such as China and India.

PSE also monitors global Liquified Natural Gas prices and how they impact imports to the United States along the Atlantic seaboard. Liquified Natural Gas is becoming a global commodity much like crude oil, which is starting to operate more on a spot market basis, where cargoes can simply be diverted to the highest priced markets. The United States seems to be in direct competition for Atlantic Liquified Natural Gas cargoes with Europe.

Q. Has PSE considered undertaking additional long-term hedging in the meantime?

A. Yes. As described in Mr. Markell's prefiled direct testimony in the 2005 PCORC proceeding, the Company analyzed and entered into two long-term, fixed gas supply agreements in October 2004 to supply fuel for its gas-fired generating fleet from November 2005 through June 2008. These contracts effectively replaced the 1993 CanWest contract that CanWest prematurely terminated effective in October 2005.

Q. Has the Company reached any conclusions with respect to undertaking additional long-term hedging?

A. Generally, the Company has concluded that it could be beneficial to expand its hedging strategies from an [redacted] month horizon to a [redacted] year horizon and to engage in more extensive hedging of its portfolios, given appropriate commodity market conditions. It should be noted that the Company also concluded that commodity market conditions between September and December 2005 were not appropriate for moving toward such a strategy. However, in late December 2005, commodity market conditions became more favorable and the Company began to hedge the maximum volumes applicable under its existing hedging strategies. The Company is not in a position to implement a more extensive hedging program at this time because of credit concerns, as described below.

4. <u>Summary of PSE's Portfolio Risk Management Efforts.</u>

Q. Please summarize the Company's efforts with respect to developing and implementing hedging strategies for its electric and gas portfolios.

A. The Company's efforts to manage its electric and natural gas portfolios within a dynamic and complex environment, as described above, can be summarized as follows. The Company has in place:

- Internal organizations and staff dedicated to managing portfolio risks;
- Executive and Board level oversight of staff's portfolio management activities;
- Specific procedures, policies and limits governing energy portfolio management activities;
- Production cost modeling techniques that develop a one hundred scenario probabilistic view of PSE's wholesale portfolios and their underlying risks;
- Use of programmatic hedging strategies which
    - specify a range of monthly volumes to be hedged, depending upon market fundamentals,
    - select specific commodities to be hedged informed by Margin at Risk analyses, and
    - permit strategies to be revised to incorporate up-to-date fundamental views of energy commodity markets; and
- A counterparty credit risk system to evaluate potential transactions with respect to credit issues.

B. Credit Issues Are a Major Concern in Implementing Risk Management Strategies

1. PSE's Limited Credit Constrains Its Ability to Expand Its Current Hedging Efforts

Q. Why is credit an important factor in today's energy markets?

A. A company's financial condition, and thus its creditworthiness, is the lens through which all prospective buyers and sellers in the markets--including PSE--look at and evaluate potential counterparties. Many companies have incurred large losses during the last few years, with some even being forced into bankruptcy. Consequently, creditworthiness has become a very important factor in determining the companies with which PSE can transact.

Q. How does a counterparty's financial condition affect PSE's risk exposure?

A. If PSE agrees to purchase an energy product from a counterparty but that counterparty fails to deliver the product when required, then PSE must go to the market to replace the product--perhaps at a much higher cost. PSE could, of course, bring a legal claim against the defaulting counterparty for the incremental costs required to cover PSE's position. But if the counterparty's financial condition is weak, then PSE may never recover those costs.

A similar analysis applies if PSE sells an energy product. If PSE delivers a product to a counterparty that fails to pay for the product, then PSE loses the entire value of the energy that has been delivered. In addition, PSE faces the exposure risk of having to resell the remaining amount of the contracted supply to another party at a potentially lower price.

Counterparties to potential transactions with PSE face the same risks with respect to PSE's performance.

Q. Are debt ratings relevant to PSE's discussions with potential counterparties?

A. Yes. Typically a company will not transact with a potential counterparty until it evaluates the counterparty's debt rating and other financial indices and determines--based on those factors--that the counterparty will likely have the financial capability to perform its contractual obligations.

PSE has the lowest "investment grade" corporate credit rating, while most of our gas and power suppliers have stronger corporate credit ratings. This puts us in a weaker negotiating position with those suppliers. PSE's credit rating and the credit ratings of PSE's currently approved counterparties are set forth in Exhibit No. ___(DEM-8C).

Since the Western Energy Crisis, and the financial decline of many merchant power plant operators, energy marketing companies, and western region investor-owned utilities, energy suppliers have become very conservative. When a company has a higher credit rating, counterparties are more comfortable increasing the level of business they are willing to do with that company.

Q. How do counterparties address these credit risks?

A. Typically, counterparties extend a certain amount of "open credit" to each other, for which no collateral is required. When a fixed-priced hedging transaction is entered into, it sets a price for the commodity comparable to market prices at that time. Then, depending upon the terms negotiated between the parties, PSE or the counterparty is required to provide collateral as the transaction's value begins to exceed the amount of open credit each has extended to the other, as measured on a mark-to-market basis. For large transactions or those that extend beyond shorter-term time horizons, companies increasingly look for some sort of collateral terms in the agreement.

Q. Would you please provide an example?

A. Say, for example, the Company locked-in 10,000 Dth per day of gas delivered over a 2-year period at $8.35/Dth and the market price then moved $2.00 down to $6.35/Dth. This would translate into a $14.6 million mark-to-market exposure. Because the market value of the gas sold to PSE is now less than PSE contracted for, the counterparty is at risk that PSE would seek to walk away from the contract, or would not be able to pay for the gas after it is delivered. The counterparty is only willing to take on so much financial risk related to its transactions with PSE, as reflected in the amount of open credit it has extended to PSE. If the $14.6 million mark-to-market exposure caused PSE to exceed the amount of open credit extended by the counterparty, this would trigger a requirement from PSE to post collateral. In addition, PSE would be required to post collateral up front as a condition to entering into any more transactions with that counterparty.

Q. Does PSE have concerns about posting collateral?

A. Yes. PSE has been reluctant to enter into transactions that would specifically require the Company to post collateral for the reasons described in Mr. Don Gaines's testimony, Exhibit No. ___(DEG-1T). The primary concern is to make sure the aggregate collateral requirements, in connection with other working capital needs, do not exceed the credit the Company has available under its bank credit lines.

The Company's reluctance is due, in part, to the fact that it is already subject to a number of agreements under which it can be required to post collateral. See Exhibit No. ___(DEM–9C). In addition, the Company is required to post collateral to a gas transportation company whose tariff has credit terms associated with debt ratings. The tariff for Gas Transmission Northwest ("GTN") provides that "creditworthiness for firm service may be evidenced by an unenhanced rating for senior unsecured debt of at least BBB or Baa2 from Standard & Poor's or Moody's, respectively, or an equivalent rating as determined by GTN." The Company is currently required to post a [redacted] letter of credit to GTN based on their credit standards.

In addition to being wary about entering into agreements that require the

Company to post collateral up front, PSE is concerned about its overall credit liquidity exposure due to the hedging transactions it has already entered into and those it is considering entering into at any given time.

Q. How does PSE measure its credit liquidity exposure?

A. As PSE's corporate credit rating is just one notch above non-investment grade, when we estimate the potential for collateral calls on the Company, we look at three scenarios. The first is that PSE's credit rating stays the same, market prices fall, and parties who have the right to call for collateral do so. The second scenario is that the Company experiences a downgrade in its credit rating, but prices remain constant. The third and most serious scenario is where the Company is downgraded, there is a negative market move, and all parties who have the right to do so call for collateral. In effect, they no longer offer open credit to the Company under this scenario because of the material adverse change in the Company's creditworthiness in a market that has increased their financial exposure relative to PSE. The reason the latter scenario must be examined is if this event were to occur, there would be significant cash flow requirements and potential liquidity constraints as the Company was forced to provide the collateral demanded by counterparties.

Q. Are these credit concern issues the same issue PSE described in its 2004 general rate case, Docket No. UG-040640 et al.?

A. The underlying issues with respect to how credit impacts wholesale market purchases and sales, and with respect to potential collateral calls, are the same. But the problem has become even more acute since the 2004 general rate case because of the significant increase in wholesale energy prices since that time. PSE currently has less "purchasing power" with respect to the units of gas or electricity the Company can acquire or hedge. This is because the higher prices on these units "use up" the Company's open credit faster since the higher the cost per unit of energy, the larger the payable obligation by PSE.

Q. Do these concerns have any practical impact on the Company's hedging strategies?

A. Yes, they do. As described above, the Company has, over time, expanded the scope of its programmatic hedging plans such that PSE now hedges [redacted] of its Core Gas portfolio (on a probabilistic basis, depending on the season and subject to credit constraints) by [redacted] months ahead of delivery, with such hedging beginning [redacted] months ahead of delivery. PSE's electric portfolio is now hedged (on a probabilistic basis) by [redacted] months ahead of delivery, with the ratable hedges accumulated beginning [redacted] months ahead of delivery. These expanded hedging programs have stretched PSE's credit standard to the limits. Thus, PSE is unable at this time, as a practical matter, to pursue additional longer-term hedging activity.

2. PSE Proposes a Credit Line Dedicated to Support of Wholesale Market Transactions, Subject to Certain Constraints

Q. Does the Company have a proposal for addressing the credit constraints described above?

A. Yes. The Company believes it makes sense to open a new line of credit that is dedicated to supporting the Company's wholesale market hedging activities. The Company is proposing in this case that the portion of costs associated with such a credit facility for electric portfolio transactions be treated as a variable commodity cost within the PCA Mechanism and that the Core Gas related costs be recovered within the PGA Mechanism. Accounting details regarding such recovery are provided in the testimony of Mr. John Story, with respect to the PCA Mechanism, and in the testimony of Mr. Karl Karzmar, with respect to the PGA Mechanism.

Q. What are the type and magnitude of costs that would be related to such a line of credit?

A. Because of the way in which credit line fees are structured, the magnitude of the costs at issue would depend on the size of the credit line PSE opens, as well as the extent to which PSE makes use of such credit line.

As Mr. Gaines' testimony describes, the size of a new credit line to support hedging activity is most likely practically limited to approximately [redacted] million, subject to change depending upon market conditions, rating agency evaluations, and changes in the Company's financing requirements. The up-front costs for such a facility would be approximately [redacted] and the annual commitment fee would be [redacted]. The costs associated with any usage of the facility to post collateral or letters of credit would vary. This is the primary reason the Company proposes to pass costs of the credit line through the PCA and PGA Mechanisms. As described in Mr. Don Gaines' testimony, recent information available to the Company suggests that the rate for funds drawn from the line would be approximately [redacted] above LIBOR and letters of credit would cost approximately [redacted].

Q. You mentioned this proposed dedicated facility would be subject to certain constraints. Please elaborate.

A. The amount of credit PSE can obtain is limited by several factors. These factors include the amounts banks would be willing to lend to PSE on an unsecured basis, the size of PSE's existing facilities, the impact utilizing such a facility would have on the Company's credit metrics, etc. As a result, PSE's ability to structure a credit facility for hedging is limited. This is why Mr. Gaines' testimony states that the size of a line of credit is effectively limited.

Q. In your opinion, would the costs of such a facility be "worth it" in terms of increased hedging capabilities?

A. Yes, I believe that over the intermediate to long-term, the costs of the credit facility would be less than the benefits of hedging. At the present time, PSE has not opened such a facility because the high-priced commodity markets have reduced the attractiveness of longer-term hedging. However, if and when the commodity markets or PSE's market view were to change such that the Company believes increased hedging activities would be a reasonable step to take, it would be much better to have the credit capacity to engage in such increased activities than to be precluded from taking this step by lack of credit. Given PSE's recent experience with the value of hedging in a rising-price environment, the costs associated with a new [redacted] million credit line seem quite small.

Q. How would such costs be allocated between the electric and Core Gas books?

A. The Company already documents and accounts for each wholesale market transaction such that the transaction is allocated to the appropriate electric or gas book at its inception and is marked to market until the transaction is paid. The Company also keeps track of its open credit on a daily basis. It would be a relatively simple matter for the Company to allocate that portion of the costs associated with the new credit facility to the electric or gas book in conjunction with the Company's existing accounting related to the PCA and PGA Mechanisms.

III. PROJECTED RATE YEAR POWER COSTS

A. Overview of Projected Power Costs for This Proceeding

Q. Please describe how PSE projected its proforma net power costs in this filing.

A. Consistent with prior general rate cases, PSE developed projected power costs for the rate year, which for this filing is January 1, 2007 through December 31, 2007. These projections are based on the information available to the Company while preparing this case for filing. As discussed by Mr. John Story in his testimony, Exhibit No. ___(JHS-1T), the resulting rate year power supply costs were then adjusted to test year levels by multiplying by an adjustment factor. This adjustment factor represents the ratio of weather normalized delivered energy loads for the test year to the rate year. Mr. Story then used that and other data to develop the revenue deficiency for the rate year.

Q. How did the Company project its power costs for the rate year?

A. As in prior cases, PSE used the AURORA hourly dispatch model to project a portion of its net power costs for the rate year. The AURORA model is a fundamentals-based production cost model that simulates hourly economic dispatch of the Company's generation resource portfolio within the Western Energy Coordinating Council ("WECC") region. AURORA thereby produces a forecast of the variable operating costs for the Company's generating resources. Additional information about the AURORA model is provided in Exhibit

No. ___(WJE-9) to the testimony of Mr. W. James Elsea. As described below, the Company's inputs to AURORA for projecting rate year power costs for this case are consistent with the Commission's power cost determinations in the Company's 2004 general rate case and 2005 PCORC.

Consistent with prior cases, the Company's projected proforma power costs also include costs not calculated within the AURORA model. Costs projected outside of the AURORA model include items such as contract costs for the Mid-C hydroelectric projects, transmission expenses, fixed pipeline charges, amortization of regulatory assets, mark-to-market for fixed-price contracts, fixed coal supply costs, peaking capacity and exchange costs, fixed capacity charges, wind integration and other power supply costs.

Q. Is PSE's rate year power supply portfolio for this proceeding different from the pro forma power cost portfolio approved in the 2005 PCORC?

A. Yes. A number of changes to the Company's portfolio have already occurred or will occur by or during the rate year for this case, in that the Company:

- Will add the Wild Horse Wind Generating Facility to its power portfolio (as discussed in the testimonies of Mr. Eric Markell and Mr. Roger Garratt);
- Will begin generating power from the Baker River Hydroelectric Project pursuant to the terms of the new license that FERC is expected to approve in 2006 (as discussed in the testimonies of Mr. Markell and Mr. Kris Olin);
- Will begin generating additional energy at the Colstrip Unit 1

generating plant resulting from turbine upgrades to the facility (as discussed in Mr. Markell's testimony);

- Will install an auxiliary boiler at the Encogen plant to convert the must-run unit to a dispatchable unit (as discussed in Mr. Markell's testimony); and

- Will procure [redacted] of long term transmission from BPA (as discussed below).

In addition, the Arizona Public Service contract presented in the 2005 PCORC expires December 31, 2006.[2]

Q. Please quantify PSE's net power cost projection for this case.

A. PSE's projected rate year net power costs, including production operation and maintenance expenses and power cost ratemaking adjustments, are $965.5 million. *See* Exhibit No. ___(DEM-10). Mr. John Story adjusts this cost to a test period level per his Exhibit No. ___(JHS-4).

B. <u>Power Cost Assumptions</u>

1. <u>Hydro</u>

Q. What historical streamflow record has PSE used in its net power cost projection for this case?

[2] PSE's contract with Powerex to serve the Point Roberts, Washington load also expires by its terms on September 30, 2007. However, PSE's power cost projections assume that this contract will be extended through the rate year because of PSE's obligation to serve Point Roberts.

A. Consistent with the Commission's February 2005 order in the Company's 2004 general rate case, PSE used the average of the 50-year Mid-C streamflow history from 1928 through 1977 to project power costs for the rate year. Projections related to PSE's owned hydro on the Westside of the Cascades were based on historical Westside streamflow records for the same period of time, consistent with the 2004 general rate case and 2005 PCORC.

Q. Why has PSE not used the 60-year streamflow history it proposed in its 2004 general rate case?

A. The Company presented evidence in its 2004 general rate case that there is no statistical basis to exclude any of the historical streamflow data relevant to the Mid-C hydroelectric generating facilities that is available, which at that time was 60 years (1928 – 1987). PSE also demonstrated that the best data to use, if one is to base power costs on a normalized forecast of hydro availability, is the average of the full 60 years of historical Mid-C data. Currently, there are 70 years of such water data available (1928 – 1997).

In the 2004 general rate case, Commission Staff agreed with the Company that there is no statistical basis to exclude any of the historical streamflow data that is available for the Mid-C hydro projects. However, Commission Staff recommended using a 50-year streamflow history (1928 – 1977) because certain rule curves, such as flood control rule curves, for the latter ten years of the 60-year period, were not developed in a manner that incorporates uncertainty in the use of water.

Although the Company does not believe the rule curves that concerned Staff materially affect the streamflow data so as to preclude use of the 70-year water data in developing a power cost baseline, the Company proposes to accept the agreed-upon methodology from the last general rate case and continue to use that 50-year streamflow data for this proceeding.

Q. Would it be appropriate to use the 120-year water data that exist for The Dalles, Oregon?

A. No, the hydrology present at The Dalles, Oregon, is too different from the hydrology at the Mid-C projects and the Company's Westside projects. For example, the streamflow at The Dalles is affected by two major rivers (the Columbia and the Snake), whereas the streamflows at the Mid-C projects are affected by one major river (the Columbia) and the streamflows at the Company's Westside projects are affected by only minor rivers, such as the Baker and Snoqualmie.

I also understand that the referenced water data from The Dalles, other than for the years 1928 – 1997, is raw data that has not been analyzed or modified to take into account factors that impact water flow such as new rules regarding upstream use of water.

2. <u>Natural Gas Prices</u>

Q. What natural gas prices did the Company use for the rate year in running its AURORA model?

A. Consistent with the Commission's order in the Company's 2004 general rate case, the Company used a three-month average of daily forward market prices for the rate year for each trading day in the three-month period ending November 30, 2005. These data were input into the AURORA model for each of the months in the rate year. To the extent the Company has fixed-priced contracts in place for natural gas for its power portfolio for the rate year, the Company adjusted for those fixed-priced contracts outside of the AURORA model.

Q. How do projected gas prices for this proceeding compare with the projected gas prices for the 2005 PCORC and the 2004 general rate case?

A. Use of a single price can be misleading in that there are different projected gas prices for each month of the rate year and for the different trading hubs from which PSE purchases gas. However, for purposes of comparison, the average price at Sumas for this proceeding's rate year is $8.57/MMBtu compared to the average rate year price at Sumas of $6.54/MMBtu for the 2005 PCORC and $5.60 for the 2004 general rate case.

Q. What factors have affected the rise in natural gas prices?

A. A number of underlying factors have prevailed for most of 2005 that have affected gas prices. Depending on the factor, each has applied upward or downward pressure on prices. These factors include:

i) Flat to declining U.S. production;

ii) Net imports below levels of four years ago;

iii) Increased global demand;

iv) High oil prices and overseas demand for crude oil; and

v) Abnormally high hurricane activity.

For a general discussion of the effect of these factors on natural gas prices, please see the brochure entitled "Residential Natural Gas Prices: What Consumers Should Know" published by the Energy Information Administration of the U.S. Department of Energy. A copy is provided as Exhibit No. ___(DEM-11).[3]

Q. Please explain the Company's source of these inputs.

A. In the 2005 PCORC and the 2004 general rate case, the Company used the forward price data published on the New York Mercantile Exchange ("NYMEX") futures market for Henry Hub. PSE then combined this Henry Hub information with relevant regional basis price differentials, such as Rockies, Alberta ("AECO") and Sumas, from the same period, to derive a forward market price for each of the eight market hubs that are input into the AURORA model for each of the months in the rate year.

For this proceeding, the Company made use of forward price data supplied by a third party service for energy and commodity market data known as the Kiodex Global Market Data ("Kiodex"). Kiodex aims to serve as a transparent, accurate, reliable and robust source of market data for firms with commodity price exposure. The Company has contracted with Kiodex for forward market price data for specific gas and power trading points. The Company was able to use the Kiodex forward prices for the rate year at each of the trading hubs that are input into AURORA rather than having to calculate differentials for each trading hub off of the NYMEX Henry Hub prices.

Q. Does PSE believe it continues to be appropriate to project natural gas prices for the rate year using forward market data from a three-month period?

A. Yes. As discussed extensively in the 2004 general rate case proceeding, the gas prices used to forecast power costs should reflect the best data available regarding gas prices that will actually prevail during the upcoming rate year. Because the price of gas is subject to market dynamics, forward market prices for natural gas are the best available indicator of what the price of gas will be during the rate year.

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[3] http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/natbro/gasprices.htm

Concerns addressed by some parties in the past that short-term market dynamics may cause temporary price excursions are appropriately addressed by using an average of forward market price strips over a reasonable period of time – such as the three month average approved in the Company's 2004 general rate case.

Q. Does PSE intend to update its projected power costs with updated gas price projections?

A. Yes. Because the factors that impact natural gas prices are constantly changing, forward market prices quickly become "stale" and their predictive power with respect to actual future prices decreases. Establishing rate year gas prices based on the average of the forward prices for the rate year for a three-month period of time closer to the beginning of the rate year will provide a more accurate projection of rate year gas prices. Therefore, while PSE used the three-month average of the forward marks ending November 30, 2005 for its direct testimony, the Company will update this data for a three-month period shortly prior to its rebuttal filing in this case and adjust its requested rate relief accordingly.

3. <u>Transmission Capacity Purchases</u>

Q. Please explain how transmission for peaking capacity is relevant to the Company's power cost projections.

A. In the wholesale power market, the preponderance of transactions relevant for PSE occur at the Mid-C trading hub. During an extreme cold event, the Company makes incremental power purchases in the real-time Mid-C market if the prices are less than the cost of generating or if additional supplies are needed to supplement the Company's resources. However, there is inadequate transmission capacity to move all of the Company's long- and short-term purchases and incremental purchases from the Mid-C to the Company's Westside system during an extreme cold event. During an extreme cold event, there is a risk that no short-term firm transmission capacity will be available. Additionally, curtailments of non-firm hourly transmission are likely to occur. Therefore, some precautions must be taken to augment the Company's electric portfolio to ensure that the Company will be able to deliver wholesale supply to its distribution system even during extreme cold winter events.

Q. How has the Company addressed this issue in the past?

A. One of PSE's past strategies for ensuring it will be able to deliver additional winter supply to its system was to acquire short-term firm transmission from BPA. Another strategy is to enter into exchange transactions where PSE will take delivery from a counterparty at a location where transmission constraints are not expected to occur, such as at the Northern Intertie or at another location west of the Cascade mountains, and simultaneously provide supply to the counterparty at the Mid-C in exchange. The Company employed both these strategies for the winter months of November 2005-February 2006.

Q. How is the Company planning to address this issue for the rate year?

A. PSE recently requested from BPA additional firm transmission from the Mid-C to PSE's system in quantities sufficient to address PSE's winter peak capacity needs. Acquisition of such capacity will also serve to address the Company's transmission capacity needs more generally. PSE's retail electric loads have been growing at an average of 2% annually. Compounding this, the amount of firm transmission cross-Cascades capacity is finite, yet many incremental regional generation sources are being directed or delivered to Mid-C. This is likely to make it increasingly difficult and more costly to obtain spot or short-term transmission capacity. PSE's request for additional firm transmission from Mid-C to PSE's service territory was made to address all of these issues. *See* Exhibit No. ___(DEM-12C).

It is expected that the cost of this transmission will be mitigated by opportunities to "remarket" excess transmission during PSE's non-peaking months of April through October and by lower secondary transmission purchases. The projected power costs for the rate year include [redacted] million of net costs for this additional transmission.

4. <u>Costs for Peaking Capacity</u>

Q. Did matters other than hydro and gas price assumptions receive particular attention in the 2004 general rate case?

A. Yes. In data requests, hearings and post-hearing briefs, there were questions regarding the Company's inclusion of costs related to winter peaking capacity. Thus, I address this type of cost in some detail below.

Q. What do you mean by the term "costs related to winter peaking capacity"?

A. As described above, the AURORA model predicts hourly *variable* costs of serving *normalized* load – that is, the load that would be expected under "normal" temperatures. Thus, the Company must add costs that AURORA does not model to project its rate year power costs. As described in the Commission's order in the 2004 general rate case, the AURORA model does not project costs associated with abnormal temperatures. *See* Order No. 06, Docket Nos. UG-040640 et al. (March 2005) at ¶ 122. However, the Company must be prepared to serve the increased load that occurs when temperatures are colder than normal and will incur costs associated with such preparation.

Q. What projections has the Company made in this case with respect to power costs associated with peak temperatures?

A. The Company has included $0.8 million in projected power costs for winter peaking capacity and $0.3 million for anticipated exchange transactions during the rate year. Unlike the 2004 GRC, the Company has not included in its power costs for this case any projected costs associated with burning oil for peaking needs.

Q. What peaking capacity costs are projected in the rate year?

A. The net position of PSE's existing resources and forecasted extreme peaking load indicates that the Company is short capacity to meet peaking needs during the winter months of the rate year. PSE has included projected costs for monthly firm index and supplemental real-time purchases (like self-insurance) and call options, as needed for the rate year winter months of January, February, November and December. PSE's projections regarding the level of costs to be incurred for the rate year winter months are consistent with the Company's planning for the current winter period, November 2005 through February 2006.

Q. How do the Company's projections of winter peaking contract costs in this case compare to the projections approved in the 2005 PCORC?

A. The forecasted cost of procuring additional winter peaking capacity to meet extreme peaking load has decreased from the 2005 PCORC due to a lower forecasted extreme peak load, partially offset by increased premium costs. The methodology for forecasting the extreme peak loads is consistent with the load forecasting methodology used in PSE's 2005 Least Cost Plan.

Q. What are the Company's projected exchange costs for the rate year?

A. The Company enters into exchange transactions to meet winter peak transmission capacity needs, as described above. The Company projects that it will be short transmission peaking capacity in December 2007, even after considering the additional transmission capacity discussed above. Exchange costs for the rate year are proformed at $0.3 million for the rate year.

5. <u>Production Operation & Maintenance</u>

Q. How has PSE developed its forecast of Production Operation and Maintenance costs in this filing?

A. In estimating rate year power costs, PSE has made the following adjustments to its test year (the year ended September 30, 2005) production operation and maintenance ("O&M") costs:

i) Proformed the O&M costs of the Wild Horse and Hopkins Ridge Wind Projects;

ii) Proformed the O&M costs of the Frederickson 1 resource based upon Epcor's forecasted operation and maintenance costs and the rate year expected generation;

iii) Normalized the arbitration settlement awarded to the Muckleshoot Indian Tribe for fish hatchery costs related to the White River Project over a three-year period (as described in the testimonies of Mr. Olin and Mr. Story);

iv) Normalized O&M for major maintenance for PSE's owned simple-cycle gas and oil-fired combustion turbines and PSE's owned Encogen and Fredrickson 1 plants based on operating cost studies and expected rate year generation;

v) Proformed the Whitehorn 2 & 3 and Fredonia 3 & 4 lease costs to reflect the lease costs expected in the rate year;

vi) Proformed the O&M costs associated with the Snoqualmie Hydroelectric Project and with the FERC relicensing of the Baker River Project; and

vii) Proformed the Colstrip O&M costs based upon forecasted operation and maintenance costs.

IV. COMPARISON OF PROJECTED POWER COSTS TO THE COMPANY'S 2005 PCORC

Q. What are the principal differences between the power cost projections in this case and the power cost projections that were approved as part of the Company's 2005 PCORC filing?

A. Exhibit No. ___(DEM-13) shows a comparison of the projected power costs for the PCORC rate year (December 2005 through November 2006) and the projected power costs for the rate year in this case (calendar 2007).

Generally, higher natural gas prices are driving higher costs for generation from PSE's gas and oil-fired resources. In turn, these higher gas prices result in higher power market prices, which increase the cost of the net market purchases in the forecast.

In addition, the projected power costs for this case reflect more market purchases due to increases in PSE's load. Power cost increases are partially offset by increased generation from the Wild Horse Wind Generating Facility as well as increased generation from the Colstrip plants due to fewer planned maintenance days in the rate year and increased generation from Colstrip Unit 1 following its scheduled major outage in 2006. Installation of the Encogen auxiliary boiler also decreases power costs due to added flexibility of dispatching on a more economic basis.

Other factors affecting power costs include increased transmission costs and escalation in the costs of PSE's existing power purchase contracts.

Altogether, the projection of power costs for this case, including production O&M and ratemaking adjustments, is approximately $90.5 million higher than what is presently reflected in PSE's PCA Power Cost Baseline Rate as established in the 2005 PCORC.

Q. How would rate year projected power costs for this case change if the Wild Horse Project were not included as a resource?

A. PSE ran the AURORA model with the same assumptions as for the rate year power costs presented in this case, except removed the Wild Horse Project. The model showed that, without the forecasted generation from the Wild Horse Project, PSE would need to purchase additional power, or would be unable to sell excess power, in the market, for a total increase in power costs of approximately $40.1 million. *See* Exhibit No. ___(DEM-14). This change in power costs does not take into consideration the other costs associated with the Wild Horse Project discussed by Mr. Story in his direct testimony.

V. CONCLUSION

Q. Please summarize your testimony.

A. PSE is actively managing the power and gas cost risks faced by its customers and shareholders through robust and sophisticated organizational structures, tools and strategies. PSE's approach to risk management avoids undue reliance on market timing while at the same time taking advantage of the expertise of the Company's traders and a broad range of industry information in order to seek to optimize the manner in which its programmatic hedging strategies are implemented.

In order to place the Company in a position to expand its longer-term hedging activities, the Commission should approve PSE's proposal to establish a separate credit line dedicated to supporting its wholesale energy market transactions, with the costs of such credit facility passed through the Company's PCA and PGA Mechanisms.

Finally, the Company's projection of rate year power costs for this proceeding – although significantly higher than the projections incorporated in the 2005 PCORC Power Cost Baseline Rate – are based on sound assumptions using methodologies approved by the Commission in the Company's 2004 general rate case and 2005 PCORC.

Q. Does that conclude your testimony?

A. Yes, it does.

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