EXHIBIT NO. ___(JMR-12CT)
DOCKET NO. UG-040640, *et al.* (consolidated)
2004 PSE GENERAL RATE CASE
WITNESS: JULIA M. RYAN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UG-040640 Docket No. UE-040641 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY, INC. For an Order Regarding the Accounting Treatment for Certain Costs of the Company's Power Cost Only Rate Filing.	Docket No. UE-031471 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY, INC. For an Accounting Order Authorizing Deferral and Recovery of the Investment And Costs Related to the White River Hydroelectric Project.	Docket No. UE-032043 (*consolidated*)

PREFILED REBUTTAL TESTIMONY OF
JULIA M. RYAN (CONFIDENTIAL)
ON BEHALF OF PUGET SOUND ENERGY, INC.

NOVEMBER 3, 2004

REDACTED
VERSION

PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY OF JULIA M. RYAN

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PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY OF JULIA M. RYAN

I. INTRODUCTION

Q. Are you the same Julia M. Ryan who submitted prefiled direct testimony on behalf of Puget Sound Energy, Inc. ("PSE" or "the Company") in this proceeding?

A. Yes.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony responds to the claim made by certain opposing party witnesses that PSE has not shown that the benefits of the improved financial position it seeks outweigh the costs to customers of achieving such improved position. I point out that they have ignored entire sections of my direct testimony that describe such benefits. In order to further explain the benefits of an improved financial position from a risk management perspective, my rebuttal testimony provides additional illustrative examples of such benefits.

My rebuttal testimony also responds to the testimony presented by other parties about various power cost related issues. I describe the proposals with which PSE is comfortable and explain why the Commission should reject others. Finally, I update the power costs submitted with my direct testimony for changes that have occurred since the time of the original filing.

II. OPPOSING PARTIES HAVE IGNORED THE BENEFITS OF AN IMPROVED FINANCIAL POSITION WITH RESPECT TO PSE'S RISK MANAGEMENT EFFORTS

Q. What is your reaction to the testimony of Dr. Wilson and Mr. Hill regarding PSE's need to improve its financial position?

A. I am disappointed and concerned that these witnesses seem to view the benefits of an improved credit rating as being limited to dollars that could be saved in direct financing costs on debt issuances. From my perspective as PSE's Vice President Risk Management and Strategic Planning, some of the most important benefits to be gained from a higher credit rating are in the area of PSE's credit position vis-à-vis counterparties in the wholesale energy market. As I described in my direct testimony, an improved credit rating would provide PSE with significantly expanded access to open credit and the associated ability to expand its current hedging activities. By contrast, further deterioration of PSE's current credit rating will significantly constrain PSE's ability to hedge energy prices. *See* Exhibit No. ___(JMR-1T) at pages 16-24.

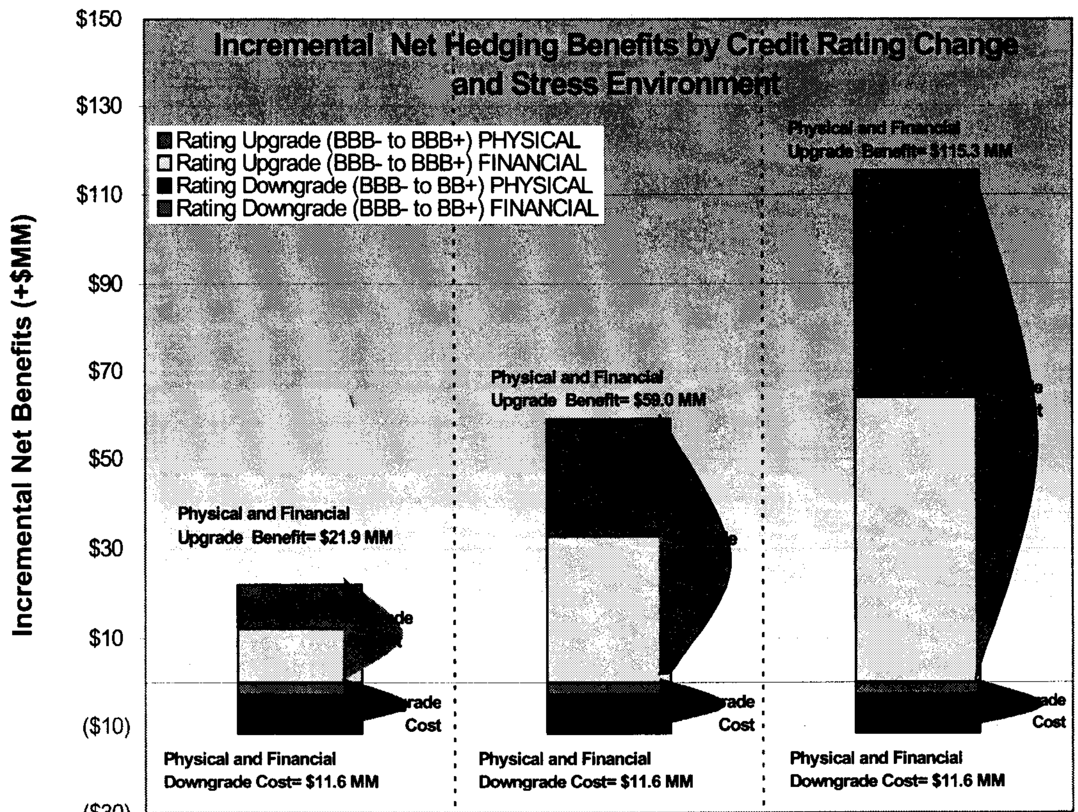
Q. Do you agree with their criticism that PSE has failed to quantify such benefits?

A. No, I believe that criticism is incorrect and unfair on several levels. First, my testimony did quantify a number of aspects of the impact of an improved credit rating. I presented a credit survey as Exhibit No. ___(JMR-8HC) showing the dollar value of additional open credit the Company believes counterparties would extend to PSE if its credit rating improved to BBB+. I also described how one translates credit availability to hedging capability with respect to wholesale energy market products given associated mark to market requirements in Exhibit No.(JMR-1T) at pages 21-23. The Company provided additional information regarding the risk management benefits associated with its request for rate relief in a number of data request responses in this proceeding. Examples of such responses are provided in my Exhibit No. ___(JMR-13C), and in Exhibit No. ___(DEG-14).

Any further quantification of such benefits, such as trying to estimate a dollar value to customers of the increased ability to hedge, is inherently a very difficult and subjective task. I believe it would be a mistake to establish a standard that such quantification must be provided as a condition of recognizing more generally the benefits to customers of increasing the Company's ability to hedge its wholesale energy market purchases. Hedging is undertaken in part to protect customers from risks of price spikes that are inherently unpredictable at the time the hedging is entered into. Hedging can also provide the additional benefit of less volatility in customers' energy bills as certain costs are fixed. A significant challenge in any attempt to create a numerical analysis is that there are many potential scenarios that can be analyzed. The size of the benefits depends upon the level of exposure assumed in the analysis.

Q. **Has PSE attempted to further illustrate and quantify the customer benefits associated with a more robust risk management program afforded by a higher credit rating of BBB+?**

A. Yes. PSE currently estimates that an improvement to PSE's credit rating from BBB- to BBB+ would provide an expected range of incremental net customer benefits in the risk management area of $21.9 million to $115.3 million, as a result of additional hedging capacity associated with additional open credit extended to PSE by trading counterparties based on the credit rating upgrade. These estimated benefits represent the range of potential exposure to increased commodity costs that could be limited with increased hedging activities under a series of different market price assumptions.



	Bank	30%/20%	60%40%
Rating Upgrade (BBB- to BBB+) PHYSICAL[1]	$9.8	$26.3	$51.4
Rating Upgrade (BBB- to BBB+) FINANCIAL	$12.1	$32.7	$63.9
Rating Downgrade (BBB- to BB+) PHYSICAL[1]	($8.8)	($8.8)	($8.8)
Rating Downgrade (BBB- to BB+) FINANCIAL	($2.8)	($2.8)	($2.8)

Stress Environment

1 Survey of Physical counterparties asked about credit extended to the Company as a result of one notch upgrade.

Q. How did PSE arrive at such a range of estimated benefits to customers of risk management activities, associated with an improved credit rating?

A. PSE's analysis is described in my Exhibit No. ___(JMR-14C).

Q. Is PSE saying that it can guarantee these avoided cost benefits if its credit rating increases to BBB+?

A. No, we cannot make any absolute assurances in this regard. The analysis depends on assumptions such as future open credit availability and market price moves. Open credit is not guaranteed, and under standard industry practices, a counterparty may elect to increase or decrease the amount of credit extended for any reason. However, the Company's analysis provides an additional illustration of potential benefits to customers of improving the Company's financial strength.

Q. Are you also providing updates to some of the exhibits filed with your direct testimony in this proceeding?

A. Yes. PSE added new physical and financial counterparties since it provided the Commission with a list of such counterparties in Exhibit No. ___(JMR-4C). Please see Exhibit No. ___(JMR-19C) for an update of Exhibit No. ___(JMR-4C). Additionally, PSE is providing the following updates:

- an update of Exhibit No. ___(JMR-6C), PSE and Counterparty Credit Ratings, is provided as Exhibit No. ___(JMR-20C);
- an update of Exhibit No. ___(JMR-7C), PSE's Financial Counterparties &

Ratings Triggers, is provided as Exhibit No. ___(JMR-21C); and

- an update of Exhibit No. ___(JMR-8HC), Counterparty Credit Survey, is provided as Exhibit No. ___(JMR-15HC).

These updates do not reflect a material change in PSE's credit position vis-à-vis potential counterparties and continue to support the conclusions in my prefiled direct testimony, Exhibit No. ___(JMR-1T).

III. OPPOSING PARTIES HAVE IGNORED THE SERIOUS CONSEQUENCES THAT WOULD ENSUE FROM A PSE CREDIT DOWNGRADE

Q. Do you have other concerns with the testimonies submitted by Mr. Hill and Dr. Wilson?

A. Yes. They appear to have ignored that the Company needs a stronger financial position to reduce the potential that it will experience a ratings downgrade to non-investment grade, and my related testimony about negative events that would be triggered by such a downgrade. See Exhibit No.___(JMR-1T) at page 21, lines 7 through 11, and page 19, line 15 through page 20 line 6.

Q. If PSE were downgraded, what would be the impact on your ability to transact in the wholesale gas and power markets?

A. The downgrade to non-investment grade would trigger several events. First, PSE could need to post collateral for the Company's gas transportation and transmission contracts, depending upon the transmission provider's tariff provisions (see Exhibit No._(JMR-21C).

Second, the Company would lose a significant amount of open credit. Based upon the survey PSE did in April and updated in October 2004 for this rebuttal testimony, this would result in a reduction of $113.8 million in physical gas, $109.1 million in physical power and $70.8 million in financial derivatives credit. See Exhibit No. ___(JMR-15HC). If the Company were utilizing then-current open credit at a BBB- rating when the downgrade occurred to BB+, and the parties to wholesale transactions required some form of collateral, the estimated cost of the credit is calculated as $11.6 million. This was calculated by multiplying the reduction in open credit by the average utility BB+ spread. See Exhibit No. __(JMR-14C). This estimate is included in the chart above titled "Incremental Net hedging Benefits by Credit Rating Change and Stress Environment".

Q. What is your estimate of the effect on collateral requirements of a market price drop and a ratings downgrade?

A. Following the release of Standard and Poor's (S&P) paper in May of 2004 "Analyzing the Liquidity Adequacy of US Energy Marketing and Trading Operations," (copy provided as Exhibit No. ___ (JMR-17), S&P required all utilities, gas and oil production companies and trading companies to file an analysis of their liquidity. The intent was to measure the collateral requirements a company might have in the event of a significant credit rating downgrade event and a negative energy market price move, and assess the ability of the company to meet those collateral requirements.

The Company prepared a liquidity analysis to submit to S&P. As of the end of June

2004, the estimated amount of collateral the Company would need to post to counterparties as a result of both a downgrade to sub-investment grade credit and as a result of market price move of 30% for the first twelve months and 20% thereafter totaled [redacted].

IV. POWER COST MATTERS

Q. Please summarize your rebuttal testimony regarding power costs.

A. This portion of my testimony responds to arguments made by other parties regarding the level of power costs that should be projected for the rate year. My testimony will address each of these items:

- Hydro Assumptions
- Transmission Costs
- Capacity Costs
- Gas Price Assumptions
- Coal Costs

In addition, I provide updated information related to power costs that were not known at the time of PSE's initial filing.

Q. What is the principle that should guide the establishment of power costs in this rate proceeding?

A. The PCA mechanism was intended to be a balanced mechanism under which there was an equal chance for under recovery or over recovery of future, expected power costs.

When rates are set using projections of future power costs that are biased or do not reflect the best information available at the time rates are set, the mechanism becomes unbalanced and fails to provide an equal likelihood that PSE's actual power costs will be higher or lower than the costs PSE is recovering in rates. For example, if the rates are set using underestimated costs, this increases the likelihood that PSE's shareholders would absorb these "excess" power costs. And, for deferred costs, it puts the burden on PSE to bear the cash flow costs and risks associated with those deferrals. If power costs are set too low, it also sends price signals to current customers that are too low regarding the costs of the power they are consuming. It also results in a large deficit being accrued in the PCA deferral account for which a different set of customers would be required to pay in the future for power consumed by customers today.

The current PCA mechanism contains sharing bands such that PSE is still exposed to significant risk of under recovery of its power costs if actual variable costs turn out to be higher than costs projected at the time rates are set. Although the PCA mechanism provides for a $40 million overall cap on the amount of excess power costs PSE must absorb over a four-year period, that cap expires June 30, 2006 and PSE's shareholders may be exposed to excess power costs thereafter. In addition, there are costs that are fixed in the PCA mechanism; therefore, it is appropriate to set these costs at the expected level using the best information then available to avoid under or over recovery of these costs.

Q. With respect to ICNU's testimony, do you believe it is appropriate to "normalize" power costs?

A. In establishing the PCA power cost baseline rate, it is reasonable to normalize loads for temperature variations and to normalize hydro generation or stream flows, assuming that is the best information available when rates are set. Weather and water are natural phenomena that are not affected by market forces. Otherwise, the best information regarding projected power costs for the rate year should be used when setting rates. Mr. Story provides additional information on this point in his rebuttal testimony.

Q. Have you updated power costs since PSE's original filing in April 2004?

A. Yes, the Company updated its power costs for purposes of this rebuttal testimony. The updated power costs are provided in Exhibit No. ___(JMR-22). Rate year power costs in this rebuttal filing are $813.4 million, a $40.0 million increase from the originally filed power costs of $773.4 million. Updating the gas price forecast for the rate year to a three-month average of forward strips for the period ended September 30, 2004, increases rate year power costs by $43.2 million. Also, the CanWest contract updates discussed by Mr. Markell in his rebuttal testimony would increase rate year power costs by an additional $1.2 million. This contract price update has not been included in the Company's power costs for rebuttal as an Accounting Petition, Docket No. UE-041846, is pending that will determine how the costs associated with this contract will be calculated during the rate year. As Mr. Story discusses, power costs need to be adjusted for this contract change based on the Commission's decision in the Accounting Petition docket. Other updates, such as changing from 60-year to 50-year hydro data, decrease rate year power costs by $3.2 million. A reconciliation between the different power cost projections is provided in Exhibit No. ___(JMR-23).

Q. Do your updated power costs incorporate any of the other parties' suggestions?

A. Yes, as I discuss in more detail below, PSE has adopted Staff's recommendation regarding hydro and coal prices and some portions of their recommendation regarding gas price forecasts. PSE has also updated rate year capacity costs.

PSE does not agree or incorporate other suggestions by opposing parties, such as Staff and ICNU regarding wheeling charges, ICNU's proposals regarding hydro and gas price projections, or ICNU's recommendation to exclude costs associated with call options or to include "savings" associated with reduced transmission losses.

V. HYDRO ASSUMPTIONS

Q. What is the Company's reaction to WUTC Staff's proposal to use the 50-year hydro period from 1928 through 1977 in estimating power costs for the rate year?[2]

A. PSE is pleased that Dr. Mariam agrees with the Company that there are no statistical grounds to exclude any water years. (See Exhibit T-___ (YKGM-1T) at 25.)

Dr. Mariam does not agree to the use of 60 years of data because run-off volumes must

[2] The 50-year period recommended by WUTC Staff uses stream flows for the years 1928 through 1977. The 40-year period last approved by the Commission used streamflow records for the years 1949 through 1987. The 60-year period proposed by the Company includes the stream flows for the years 1928 through 1987. At some time in the near future the historical data for 1988 through 1998, an additional 10 years, is expected to be available.

be "estimated" rather than "observed" for the most recent ten years. He states that until the Northwest Power Pool and Federal agencies such as BPA develop rule curves based on "estimated" run-off volumes for the most recent ten years, 50-year data should be used.

Q. What is the Company's reaction to using the 50-year hydro data as proposed by WUTC Staff?

A. PSE does not share Staff's concern that the rule curves issue is a significant problem with use of the 60-year data. However, for purposes of this proceeding, PSE is willing to use the 50-year period from 1928 through 1977 in projecting power costs for the rate year, as proposed by Dr. Mariam. Changing from 60- to 50-years of hydro data decreases projected power costs by $2.0 million from PSE's original filing.

Q. Mr. Schoenbeck states for ICNU that PSE should continue to use 40 years of hydro data until the Commission issues a different standard for all three utilities in Washington State. Do you agree?

A. No, I do not. ICNU does not contest Dr. Dubin's statistical analysis or conclusions, and instead essentially argues for delay in moving to a set of water years that is more appropriate and statistically sound than the current method. I understand that this Commission does not conduct common rate proceedings to set rates and that each utility needs to address what is important within its individual portfolio in a rate case. PSE has come to the Commission seeking relief on an issue that has significant financial consequences for the Company and has supported that request with extensive data and analysis that has not been presented to the Commission in prior proceedings.

As set forth in the direct testimony of Dr. Dubin, use of the 40-year hydro data is not appropriate and is too short for a geological series such as this. Further, there is no statistical reason to exclude the data from the first 20 years of the 60-year data series. The only other party to submit evidence on the subject (Commission Staff) has submitted evidence that supports the Company's conclusions that use of the 40-year data is inappropriate.

By continuing to use 40-year data to set baseline power costs, the Company would be using a hydro runoff that is artificially low to set rates and a hydro runoff that the Company and others in the region do not use for planning purposes. The result forces PSE to incur more power costs in the initial sharing bands of the PCA mechanism where the Company assumes a greater share of the power costs. This is detrimental to the Company's earnings capability and its ability to improve its financial strength.

VI. TRANSMISSION COSTS

Q. WUTC Staff proposes removing PSE's estimate for increased transmission expenses on the BPA system, whereas ICNU proposes a true-up based upon the actual BPA settlement, provided it is completed by the time of the Commission's final order. What is PSE's position?

A. BPA's current transmission rates expire September 30, 2005. When PSE filed its direct testimony on April 5, 2004, PSE provided an estimate of a 15% rate change effective

October 1, 2005, based upon a preliminary estimate provided to PSE by BPA. Since then, BPA has held several transmission rate workshops, and PSE has participated with other BPA customers in several preliminary rate case settlement discussions. BPA's latest estimate is for a 25.1% increase in the rate under which PSE receives the majority of its transmission service.

The Company agrees with ICNU that, should a settlement with BPA be reached before the Commission's final order, the power costs should reflect what is agreed to between BPA and its customers. However, if there is no agreement prior to the Commission's final order, PSE proposes to use a 14% increase, which is the approximate average increase in transmission rates foreseen by BPA for all classes of customers. PSE's rebuttal power costs reflect a 14% rate increase in BPA's wheeling costs effective October 1, 2005, which increases power costs by $1.9 million.

VII. CAPACITY COSTS

Q. Do you have any proposed changes to the peaking costs presented in your pre-filed direct testimony?

A. Yes, I do. The projected peaking costs for PSE's winter peaking needs in the rate year are being revised in connection with both the planning the Company is doing for the current year (November 2004-February 2005) and the projected volumetric needs for the rate year. In addition, the Company adjusted its available combustion turbine units' capacity to reflect increased availability at lower temperatures. The revised costs of $2.8 million reflect $1.2 million for transmission exchange agreements and $1.5 million for other capacity costs and are a reduction of $2.7 million from the costs originally filed in this case. Please see Exhibit No. ___(JMR-24C) for a detail of the forecasted capacity costs.

Q. Do you agree with ICNU's assertion that peaking costs should be removed completely from the calculation of the power cost baseline?

A. No, I fundamentally disagree with their proposal. The Company obtains peaking resources to supplement available company resources to reliably serve winter peak load. The peaking resources include both transmission solutions to mitigate curtailment risks east to west across the Cascades, as well as contracts to provide actual peaking capacity or hedges to protect against the cost of acquiring peaking resources in the market at the time they are needed. An overview of how the Company is planning for its winter November 2004 through February 2005 peaking needs is found in Exhibit No. ___(JMR-25C), which is a presentation called "Update on Winter Peaking Capacity Purchases" dated October 14, 2004, and Exhibit No. ___(JMR-26C), which is a presentation entitled "Winter 2004-2005 Transmission Assessment for Extreme Peak Planning" dated Sept. 16, 2004.

Q. What kind of peaking products may the Company obtain in the market?

A. PSE has used several types of call options to hedge the peaking capacity risk. Some have been physical calls at MidC or other locations that allow the Company to call on physical power at a pre-determined price. PSE could also use financial calls that provide a financial payment based upon the difference between the posted peak market price at MidC and the strike price (to offset the costs of purchasing physical power). And some of the calls are “dual-trigger” calls that also have an associated temperature strike, along with a price strike. There are different costs, depending upon the type of product. Additionally, the call premium costs are impacted by market volatility and time value (time remaining until the options expire). As a result, the costs of these calls are not constant from year to year.

Q. ICNU indicates they believe these are not effective hedges. Why do you believe they effectively serve as an important resource to serve peak load?

A. The daily call options PSE has purchased are one of the few products the Company can purchase in the market that can help cover price and volume risks associated with an extended extreme winter peaking event. The call options provide a sort of “disaster insurance” for a multiple-day winter peaking event in a high-priced market environment.

The Company does recognize that, although daily call options provide valuable protection, they are not a perfect hedge. Daily call options are exercised on a day-ahead basis and do not provide price protection in the real-time markets, which are typically more volatile than day-ahead. No product currently exists in the market for real-time price protection. For the extreme end of the load duration curve associated with several hours of peaking requirements in the most extreme situations, PSE is "self-insuring" by relying on purchases from the real-time markets at a premium.

Q. Why are regional exchanges important in connection with winter peaking planning?

A. Most of the day-ahead options are available only at the MidC market location. With the MidC as the primary source of regional market supply, many of the Company’s incremental purchases are from that location. PSE must review its transmission capacity against its purchases. On peak days, the power purchases at MidC can exceed PSE's available transmission capacity from MidC to its service territory. Short-term transmission may not be available to move the additional supply required or is available on a non-firm basis, and transmission constraints may occur. Therefore, PSE must either risk curtailment, enter into additional transmission contracts to meet peak day needs, or enter into exchange transactions to re-balance the portfolio so that PSE can mitigate the risk of transmission constraints. PSE's planning criteria is to reduce the risk of curtailment, and for the last few years, the exchange transactions have proven to be more cost-effective than entering into additional transmission arrangements.

Q. ICNU proposes a reduction in power costs for savings associated with reduced line losses. Is this appropriate?

A. No, this is not an appropriate adjustment. When PSE analyzes the cost effectiveness of transmission exchanges, consideration is given not only to the direct cost or benefit of entering into the exchange, but also the indirect costs or benefits. The direct cost or benefit is the premium paid or received. The indirect cost or benefit is the 1.9% physical line losses PSE would not have to pay BPA for firm transmission across BPA lines since the Company will wheel within its existing transmission contract nominations. This cost not incurred is considered to be a savings. This savings, however, is indirect in that the losses are reduced. These losses are part of the line losses represented in the 6.4% difference between GPI (Generated Purchased & Interchanged) and billed sales. In addition, as PSE has entered into these exchanges for several years now, the historical line losses included in this case already reflect the benefit of lower line losses. And, also note that billed sales flowing through the PCA mechanism reflect these actual, lower, line losses.

VIII. GAS PRICE ASSUMPTIONS

Q. With respect to the gas price forecast in power costs, ICNU proposes that the appropriate gas price to employ in calculating the base power cost in this proceeding should focus on the period beyond July 1, 2006. Does this make sense?

A. No. The gas prices used to forecast power costs in this rate case should reflect forecasted rate year gas prices and market conditions, not projected market conditions from periods unrelated to the rate year, beyond early 2006. The power costs in this rate case will determine the baseline power costs for the PCA mechanism. These costs should reflect the best data available regarding power costs for the upcoming rate year. As such, the fuel cost should be estimated using information relevant to the rate period.

Mr. Markell's testimony provides additional reasons why use of an average gas price from forecasts for the period 2006-2011 is inappropriate.

Q. What is the history of projecting gas prices in PSE's rate-related filings?

A. To develop projected prices for PSE's prefiled direct testimony in this proceeding, the Company used an average of the forward market prices for natural gas over a 10-business day period. This NYMEX-based methodology utilizes the forward market prices at Henry Hub over a ten day business period as published on the New York Mercantile Exchange ("NYMEX") futures market, with a regional basis price, to derive a forward market price for the market locations from which PSE sources natural gas. The Company has utilized a similar methodology in Purchased Gas Adjustment ("PGA") filings since the mid-1990s. It also utilitized this methodology in its Power Cost Only Rate Case ("PCORC"), which had not been decided at the time of PSE's April 5, 2004, filing in this proceeding.

Q. Has PSE considered adopting fundamental forecasts as a means for setting gas prices in PGA or rate year power cost filings?

A. Yes, but PSE believes a NYMEX-based methodology is better because of availability, transparency and accuracy for rate setting purposes. While fundamental forecasts tend to track the forward markets at the time they are issued, the near-term prices quickly become stale. The fundamental forecasts also tend to use standardized time periods that do not necessarily correspond to the time periods of the Company's rate years. Additionally, the forecasts are developed intermittently, whereas forward market prices are nearly always available. For rate setting purposes, PSE needs to have a price determination methodology that can be updated in a timely manner to provide gas prices for the power cost analyses immediately prior to the rate filing date and again to update power costs for rebuttal testimony. The fundamental forecasts do not provide this timeliness and availability.

PSE believes that for relatively short-term price determination (up to 2 years in the future), the NYMEX-based forward market methodology is an appropriate methodology. The use of fundamental forecasts is appropriate for longer-term studies (between 2 and 20 years), such as for resource and least cost planning. PSE has used fundamental forecasts for least cost planning and other long-term analyses for several years. PSE has not used fundamental forecasts for determining gas costs in rate case proceedings for either gas or power rates since 1990.

Q. Are there aspects to Dr. Mariam's analysis that you would support using for projecting gas prices for the rate year?

A. PSE agrees with Dr. Mariam that establishing the rate year gas prices by using the average of the forward prices for the rate year for the three months prior to the beginning of the rate year may be the best estimate. However, as Dr. Mariam states at Exhibit T-___(YKGM) at 31, it is not practical to use these prices in this proceeding, given that this issue is contested and the matter will proceed to hearing well before March 2005. Therefore, PSE proposes to use the three-month average of the forward marks ending September 30, 2004. This price would be $5.60 per MMBtu for the Sumas market hub, as opposed to both the price in Dr. Mariam's errata testimony of $4.69 per MMBtu and the price in the Company's original testimony of $4.39 per MMBtu. For comparison, a ten-day price strip for September 30, 2004 would be $5.76 per MMBtu.

Q. Is this a deviation from previously established practices for setting gas prices in PSE filings?

A. Yes, this would mark a change in PSE's methodology. But after conducting analyses of this approach, the Company has determined that it could use this method to set gas prices in power costs. Use of the average of the most recent three months' NYMEX futures has been evaluated and is supported by the testimony of Dr. Dubin. Please see Exhibit No. ___(JAD-15T).

Q. Is there another theme that you support in Dr. Mariam's testimony?

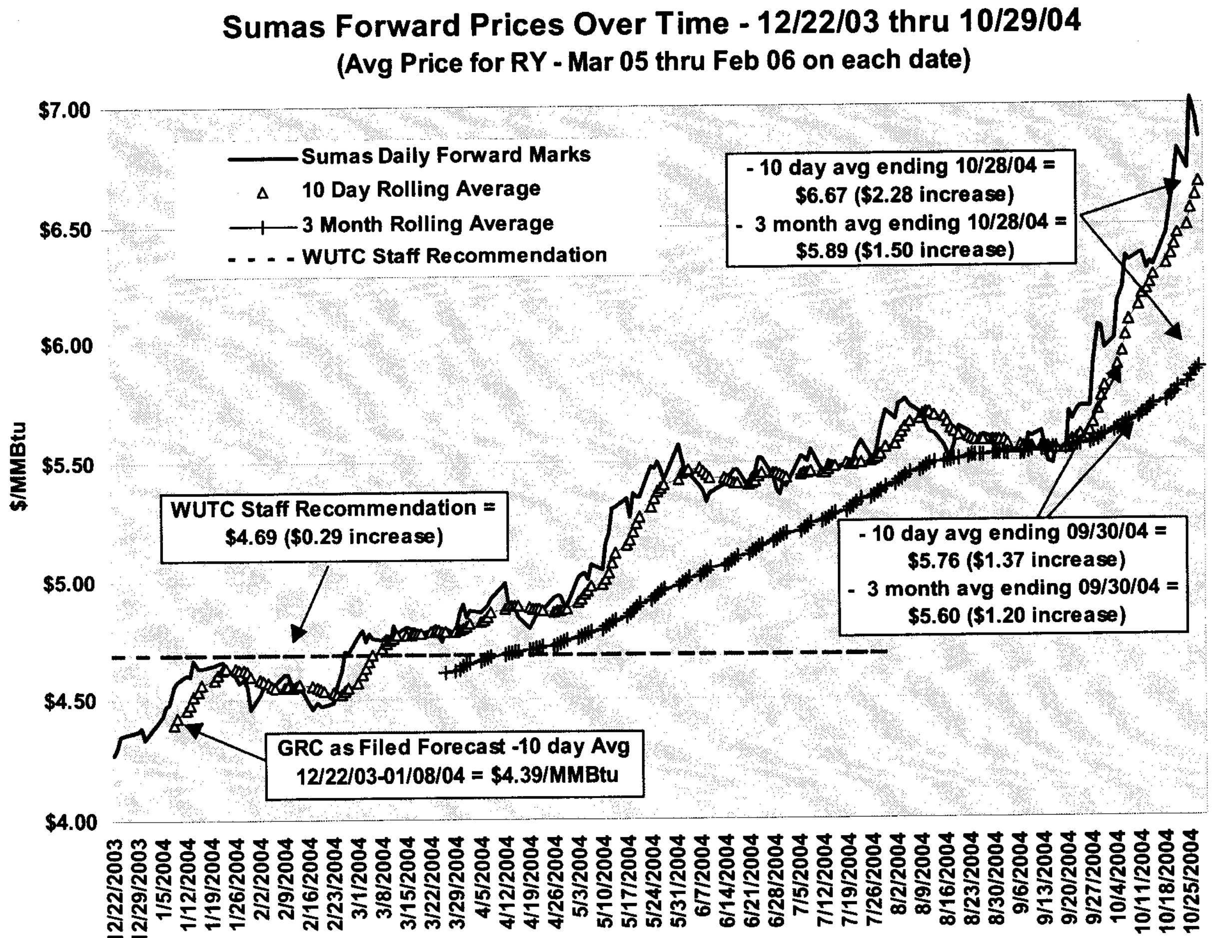
A. Yes. In addition to providing testimony supporting the concept of the three-month strips, he cautions against setting gas prices at too low a level in the PCA baseline:

> " Setting gas prices as low as that proposed by PSE [in its April 2004 filing], in light of the fact that projections of forward gas prices by EIA are above $5.00/mmbtu, would result in a skyrocketing deferral in the PCA account. Increases in the deferral account would result in reduced cash flows to the Company and continued increase in electric rates to ratepayers." Exhibit ____ (YKGM-1T) at _____.

The Company agrees.

Q. What has occurred to gas markets since you filed testimony in April 2004?

A. Natural gas prices have risen sharply. Below is a chart showing how the forward prices for the Rate Year have changed over the period of December 2003 through late October 2004. As shown, the prices (using the 10-day average for comparison purposes) have risen from $4.39 per MMBtu for the period ending January 8, 2004 (used in the Company's April 2004 filing) to $5.76 for the 10-day period ending September 30, 2004, an increase of $1.37 per MMBtu. At this point, PSE has no reason to believe that gas prices for the rate year will move back to levels that were used in PSE's original filing. Indeed, as shown in the chart, prices continued to rise during October.



Q. Do you agree that there is an annual seasonal pattern in the period of May through July where gas prices in the forward markets tend to rise during summer months, as suggested by Commission Staff?

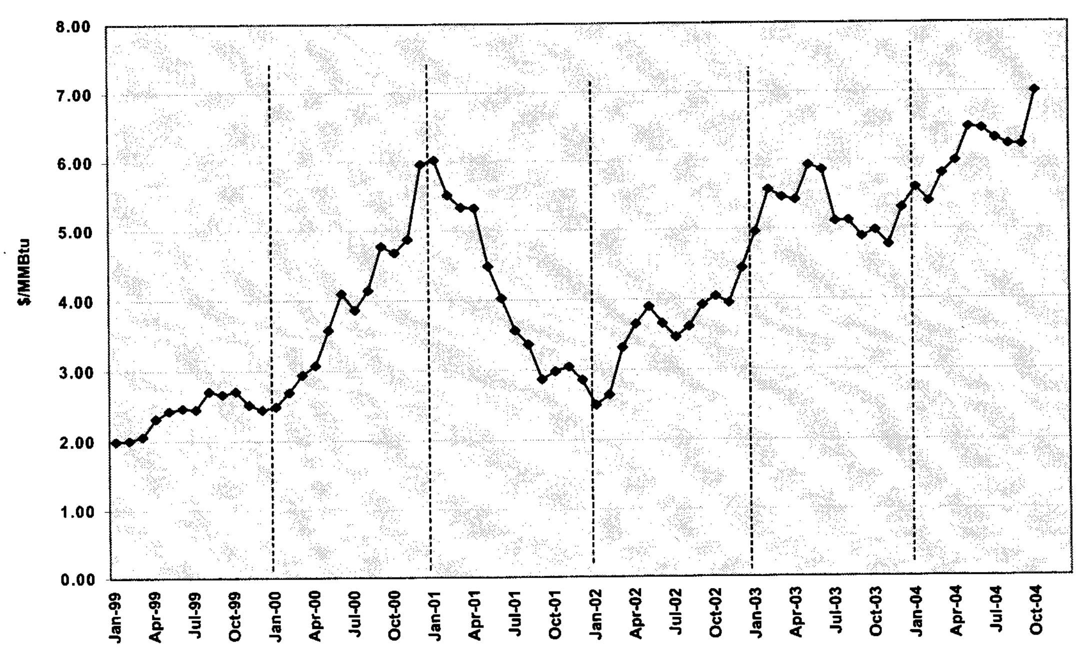
A. No. Dr. Dubin analyzed the relationship between NYMEX forward market prices and spot market closing prices over the 1991 through 2004 historical period. As discussed in Dr. Dubin's rebuttal testimony, Exhibit No.___(JAD-15T), he found no seasonal pattern. Thus, the data do not support Commission Staff's proposal to exclude months post-April 2004 in the three month average strips used to project gas price.

Q. Has PSE conducted any analysis on the seasonality issue?

A. Yes, PSE developed a chart showing the historical 12 month rolling average forward market prices for the period from January 1999 through October 2004. As shown below, the dominant price trends are of long, annual duration, as opposed to seasonal patterns. The forward twelve-month prices move up and down without a strong seasonal bias in the months of May through July.

This analysis further supports the conclusion that exclusion of months after April 2004 would not be appropriate.

Monthly Avg 12 Month NYMEX 1999 - 2004



IX. COAL COSTS

Q. Do you agree with Staff's coal price adjustment?

A. Dr. Mariam proposed in his testimony to increase the cost of coal for the rate year and I agree that the cost of coal has increased. The simple average cost of coal Dr. Mariam quotes, however, should actually be $0.6122/MMBtu for Colstrip 1&2 and $0.6220/MMBtu for Colstrip 3&4 (instead of $0.625/MMBtu and $0.618/MMBtu, respectively). Accordingly, power costs have increased $1.5 million to reflect increases in coal prices. Mr. Markell's testimony clarifies the cause of the cost increase.

X. CONTRACT UPDATE

Q. Have you updated any contract information for purposes of this rebuttal filing?

A. Yes. In October, 2004, the contract price and expected power deliveries were updated in accordance with the WNP-3 Settlement Exchange Agreement with BPA ("WNP-3"). The Company has included these updates in the Company's power costs filed with this case, decreasing power costs $1.5 million.

In addition, a contract providing physical gas to the Tenaska unit with a forecasted $0.02/MMBtu gain was terminated, causing power costs to increase $300,000. The benefit of this original contract with the Core Gas portfolio was to ensure the delivery of gas on a daily basis to the Power Portfolio for Tenaska. In recent history, given the relatively low market heat rates, the plant has not dispatched daily. Going forward, in lieu of paying a premium for gas supply that may not be required every day, the Power Portfolio will obtain physical gas supply as needed, in combination with applicable forward market hedges.

XI. PRODUCTION O&M UPDATES

Q. What updates have been included in the production O&M?

A. One of the largest costs within the production O&M is that associated with the Colstrip units. PSE pays for its share of costs of operating and maintaining the Colstrip units. Since PSE's initial filing in this docket, PSE has received updated budgets from PPL Montana, the plant operator. Production O&M costs have been increased by $1.2 million to reflect these updated budgets.

XII. CONCLUSION

Q. Please summarize your testimony.

A. Commission Staff and Public Counsel have ignored significant risk-management related benefits that would result from improving the Company's financial strength, as well as serious consequences that would result from a credit downgrade.

With respect to power cost issues, the Company has carefully considered the proposals made by other parties to this proceeding, and has accepted several proposals. However, the Commission should reject the other proposals for the reasons stated in my testimony, and approve the Company's updated power costs as submitted in this rebuttal.

Q. Does that conclude your testimony?

A. Yes, it does.

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