BEFORE THE WASHINGTON UTILITIES AND

TRANSPORTATION COMMISSION

UE-031725

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION	)
	)
Complainant,	)
	)
v.	)
	)
PUGET SOUND ENERGY, INC.	)
	)
Respondent.	)
	)

2003 POWER COST ONLY RATE CASE

DIRECT TESTIMONY OF

DONALD W. SCHOENBECK

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

NON-CONFIDENTIAL VERSION
PER WAC § 480-07-160 AND PROTECTIVE ORDER
IN WUTC DOCKET NO. UE-031725

January 30, 2004

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald W. Schoenbeck. I am a member of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I've been involved in the electric and gas utility industries for over 30 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters before numerous state commissions, public utility governing boards, governmental agencies, state and federal courts, the National Energy Board of Canada and the Federal Energy Regulatory Commission ("FERC"). I have appeared before the Washington Utilities and Transportation Commission ("WUTC" or "Commission") at least 20 times since 1982. A further description of my educational background and work experience is summarized in Exhibit No. ___ (DWS-2).

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association, whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Puget Sound Energy ("the Company" or "Puget").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the proposed power cost increase Puget is seeking in this docket. It is important to note, however, that we have performed a detailed review of only select cost items due to the abbreviated time schedule for filing testimony in this proceeding. The limited time frame for this proceeding is particularly unfortunate given the fact that this is the most analytically complex filing Puget has submitted in all of the time that I have appeared before this Commission. Accordingly, my testimony does not address numerous other matters of concern raised by the Company's filing. This silence should not be construed as acceptance by ICNU of the Company's proposals on all these other items.

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. The Company's filing proposes a rate increase of $64.4 million (or 4.7%) attributable to the proposed acquisition of the Frederickson 1 project ("Frederickson") and cost pressures in all other power-related areas. Significantly, only $18.3 million of the proposed increase is associated with the acquisition of Frederickson. The remaining $46.1 million is associated with all the other proposed modifications to production-related accounts.

The power cost adjustments proposed by ICNU in this testimony result in a rate ***decrease*** of $15.1 million (or –1.1%), which is a difference of $79.5 million from Puget's proposal. Roughly one-half of the ICNU adjustments—about $39.3 million—are attributable to matters related to projecting the appropriate level of base power costs for the rate period given the fact that the Company has a power cost adjustment mechanism ("PCA"). My approach is based on using normalized results of operations to set the baseline. This is totally different from Puget's approach, which looked at the costs the Company could incur during the April 2004 through March 2005 time period. The specific adjustments I address related to base power costs include: 1) the availability of the Colstrip generating units; 2) the amount of energy Puget should assume it will receive under the March Point power purchase agreements; 3) the gas price used by Puget's AURORA model (a fundamentals power cost model); and 4) a reasonable level of expense for call options used to reserve peaking power. The first three of these adjustments result in a reduction of the costs Puget has requested in this proceeding of approximately $29.5 million. This result was produced running the AURORA model through all 40 water years. The bulk of this amount is related to an adjustment to the gas price used by the Company. The fourth issue, related to the call options reduces the costs requested by Puget by about $9.8 million.

The remaining, but substantial, $40.3 million difference between ICNU's adjusted base power cost and Puget's proposal relates to the Tenaska power purchase agreement and the associated regulatory asset. In this proceeding, Puget is seeking a cost increase for the power procured from Tenaska that is far in excess of the contractual rate under the original contract. The Commission deemed this rate to be imprudent in docket numbers UE-920433, UE-920499 and UE-921262. Subsequently, in docket number UE-971619, the Commission approved the creation of a regulatory asset associated with the Tenaska agreement based upon Puget's restructuring or amending the contract. At the time Puget restructured the contract, the Company projected that the agreement would produce a substantial ratepayer benefit. In actuality, however, ratepayers have incurred substantial additional costs under the restructured Tenaska contract and these costs exceed the likely remaining benefit. Accordingly, ICNU recommends that the regulatory asset be written off and removed from rate base.

Finally, ICNU presents the class specific rate decreases using the same cost allocation and rate spread proposed by the Company.

II. BACKGROUND AND SUMMARY OF PUGET'S REQUEST

Q. PLEASE EXPLAIN THE BASIS FOR THE COMPANY'S APPLICATION.

A. The Company filed its application pursuant to a multiparty settlement that was adopted by the Commission on June 20, 2002, in Puget's last general rate case, docket number UE-011570. ICNU was a signatory party to the Settlement Stipulation for Electric and Common Issues in Docket UE-011570, which provided an overall resolution of the general rate case issues, but ICNU was not a party to the Settlement Terms for the Power Cost Adjustment Mechanism ("PCA Stipulation"), which is the specific agreement under which the Company made the filing at issue in this Docket.

Under the PCA Stipulation, Puget was authorized to submit a "power cost only rate case" ("PCORC") to update the base power cost level. It is under this particular provision that Puget submitted its filing in this Docket. In submitting this update, adjustments may be proposed to all aspects of the Company's power-related costs including the addition and retirement of resources. In the instant filing, the Company is proposing numerous changes to the various accounts while also seeking the authority to purchase and put in rate base a 49.85% interest in Frederickson.

The PCA Stipulation also instituted a PCA for Puget, which sets forth the manner in which annual deviations in actual power costs from a base power cost level would be shared between the Company and its customers. The PCA includes a sharing mechanism, which consists of four bands or levels for power cost deviations with a corresponding sharing percentage. For the first $20 million deviation (either plus or minus), the Company absorbs 100% of the cost or benefit. The second band is for deviations of $20 to $40 million. These amounts are shared equally between the Company and its customers (50%-50%). The third band is for deviations from $40 to $120 million with the Company being responsible for 10% and customers for the remaining 90%. Finally, the fourth band is for deviations in excess of $120 million. In these cases, the Company is responsible for 5% and customers are responsible for the remaining 95%.

The PCA also contains a cumulative sharing mechanism for the initial period of July 1, 2002, through June 30, 2006. During this term, the customers are responsible for 99% of any deviation should the Company's share of the power costs exceed $40 million. Based upon Company assertions, it is my understanding that the Company is close to—if it has not already—reached this cumulative value. Therefore, 99% of any further increases in power cost above the base rate level will be recovered from the Company's ratepayers.

Q. WHAT IS THE IMPACT IF THE COMMISSION INCREASES THE BASELINE LEVEL POWER COSTS USED TO SET THE PCA, BUT ACTUAL POWER COSTS END UP LOWER?

A. If the Company's actual power costs are lower than the baseline, the Company will retain all of the benefit for the first $20 million.

Q. HOW HAS PUGET CALCULATED THE PROPOSED REVENUE INCREASE IT IS SEEKING IN THIS APPLICATION?

A. Exhibit A to the PCA Stipulation illustrates the method for converting the proposed power costs into a baseline rate. Using this method, the Company's filing is seeking to increase the baseline rate value from $43.95/MWh to $47.15/MWh. Based upon test period loads, the resulting proposed revenue increase is $64.4 million or 4.72%. See Exhibit No.___ (JHS-6).

Q. IS IT POSSIBLE TO ISOLATE THE IMPACT OF THE ACQUISITION OF FREDERICKSON ON THE OVERALL RATE REQUEST?

A. Yes. Staff's data request number ("DR") 2 asked Puget to calculate the revenue requirement excluding the acquisition of Frederickson. The response indicates that the baseline power rate would be $46.24/MWh. PSE Response to Staff DR No. 2 at 3 (Nov. 18, 2003). This power rate translates into $46.1 million of the $64.4 million rate increase requested by Puget in this proceeding. Consequently, the associated revenue requirement from the acquisition of Frederickson is only about $18.3 million. Thus, the majority of the revenue increase Puget is seeking in this proceeding is not associated with the acquisition of Frederickson; rather, it is associated with cost pressures in all of Puget's other production-related accounts.

III. ICNU POWER COST RECOMMENDATIONS

Q. HAVE YOU ANALYZED THE ADJUSTMENTS PUGET IS PROPOSING IN THESE OTHER ACCOUNTS?

A. Given the limited time available to comprehensively review, analyze and respond to Puget's complex filing, we have focused our efforts on a just a few critical matters that have a significant impact on the normalized base power level.

Q. WHAT SHOULD BE THE STANDARD OF REVIEW TO TEST THE REASONABLENESS OF PUGET'S PROPOSED ADJUSTMENTS?

A. Since we are establishing the base power cost to be reflected in rates and used to measure deviations from actual costs in the PCA, the only acceptable standard should be a normalized cost level. This means that the cost to be utilized in determining the base level is not necessarily the expected cost for the rate period that the Company will or may incur. Instead, the costs used should be based on normalized costs.

This critical point can be illustrated with an example. Assume Puget has the ability to know precisely the production-related costs it will incur for the rate year (April 2004 through March 2005) in each and every account. This includes knowing that all Colstrip units will be out of service for 6 months, that the Pacific Northwest will experience its lowest historic hydro conditions, that unreasonable gas costs will occur, and short-term power market prices would exceed all historical highs to date. Establishing a base power cost using this precise knowledge of extraordinary conditions would be inequitable to ratepayers because it would essentially eliminate the PCA risk sharing bands in favor of the Company. In other words, with a base power cost that assumes these extreme circumstances, there would be no sharing of adverse market events between the Company and ratepayers through the PCA. Ratepayers would be responsible for 100% of the costs through the base rate charges. Moreover, in subsequent years, the Company would receive an inappropriate windfall from always having actual power costs be below the base level used to establish rates. This example illustrates why it is paramount that the base power costs in this proceeding be determined using a "normalized" cost standard and not a "next year" or adverse cost standard.

Q. HAS PUGET EMPLOYED A NORMALIZED STANDARD IN DERIVING THE PROPOSED BASE POWER COST IN THIS PROCEEDING?

A. In some cases, Puget has utilized a normalized standard. For example, Puget used hydro data for 40 hydro years to calculate expected hydro generation instead of selecting one particular year. In other instances, however, Puget has failed to use normalized data. These latter instances include the availability of Colstrip, the expected generation from the March Point qualifying facilities, the gas price forecast used as an input to the AURORA model run, and the call option expense Puget is proposing to recover. I propose adjustments related to these issues based, in part, on Puget's failure to normalize the effects of these issues on power costs.

A. COLSTRIP GENERATION

Q. PLEASE DESCRIBE YOUR CONCERN WITH PUGET'S PROPOSED ADJUSTMENT WITH REGARD TO THE COLSTRIP GENERATION.

A. Puget has substantially understated the availability of Colstrip Unit 3 during the rate year, resulting in a power cost increase of approximately [redacted] (AURORA run, single average water year). For Colstrip Units 1, 2, and 4, Puget used the specific maintenance outage schedule provided by the plant's operator to model the availability of these units for the rate year. [redacted][1] See Exhibit No. ___ (DWS-3C) at DWS/2-3. Imputing this additional outage time results in an availability factor for Unit 3 that is far below historical performance levels or industry norms for units of this size. This additional outage time increases the Company's power costs by [redacted] and is a clear case of Puget's use of a "next year" standard to set its power costs instead of a normalized standard.

Q. WHAT IS THE ENERGY PRODUCTION FROM COLSTRIP USING PUGET'S PROPOSED AVAILABILITY?

A. As shown by the following table, Puget's PCORC proposal results in 4,809 gWh of Colstrip generation being delivered to the Company's service territory. This amount is 65 gWh (or 1.35%) less than the energy deliveries agreed to in the last general rate case

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[1] In this version of ICNU's Testimony, confidential and highly confidential information is redacted.

settlement. Because the incremental cost of Colstrip generation (about $6/MWh) is substantially less than the projected market price for power (about $40/MWh), even this relatively minor reduction in energy generation increases Puget's power costs by roughly $2.2 million dollars.

Colstrip Generation Comparison
(gWhs)

	Last GRC	PCORC	Delta
Units 1 & 2	2,236	2,308	72
Units 3 & 4	2,638	2,501	-137
Total	4,874	4,809	-65

Q. HOW SHOULD THE AVAILABILITY OF COLSTRIP BE DETERMINED FOR BASE POWER COSTS IN THIS PROCEEDING?

A. A workpaper of Mr. William Gaines indicates the historical availability of these units for the past seven years. <u>See</u> Exhibit No. ___ (DWS-3C) at DWS/1. [redacted] I recommend that these values be used as a target for the expected Colstrip generation in this proceeding. In using a seven-year average, the expected value includes a large number of years with a wide range of planned and unplanned outage conditions, not giving too great a weight to any one particular year.

The following table compares the expected generation under the Company's "next year" PCORC proposal with the ICNU recommendation.

Colstrip Generation Comparison
(gWhs)

	Puget	ICNU	Delta
Units 1 & 2	2,308	2,230	-78
Units 3 & 4	2,501	2,666	165
Total	4,809	4,896	87

As indicated by the table, ICNU's recommendation increases the Colstrip generation proposed by Puget in this case by 87 gWh (87,000 MWh). By way of comparison, ICNU's recommended generation is only 23 gWh (or 0.5%) higher than the settlement value in Puget's last general rate case (UE-011570). The Commission should adopt this level of Colstrip generation for the rate period. If the Commission adopts this adjustment, it should require Puget to perform an AURORA run with this adjustment included to determine base power costs.

B. MARCH POINT GENERATION

Q. HOW HAS PUGET PROJECTED THE EXPECTED ENERGY FROM MARCH POINT 1 AND 2?

A. It appears that Puget has relied on the AURORA model to project the expected energy from the March Point facilities based upon the assumed forced outage rate, maintenance rate, and must run factor. With regard to March Point 1, Puget has changed the must run factor used in the prior proceeding from 50% to 100%. See Exhibit No. ___ (DWS-4) at DWS/5. With this modeling input value, Puget will acquire the maximum amount of energy from the facility because it will not be economically displaced. As a result of this change, Puget's projection for energy from this facility has increased by 98 gWh as compared to the last general rate case.

Q. IS THE ENERGY PRODUCED FROM PUGET'S MODELING OF THE MARCH POINT FACILITIES REASONABLE?

A. For March Point 2, the Company's modeling result is within a reasonable range. However, for March Point 1, the facility has not achieved the Company's projection in the last nine years of operation. Exhibit No. ___ (DWS-4) at DWS/1-2. The following table shows the historical generation for March Point 1 and March Point 2 for 1994-2002 taken from Exhibit No. ___ (DWS-4). The closest year of historical generation to the Company's 12-month projection is 1996, but even this year falls short by 13 gWh. Comparing the Company's projection to either the nine or four-year averages shows that Puget has overstated generation between 43-50 gWh. Since the cost of operating March Point 1 is higher than projected market prices, higher assumed generation from the plant increases baseline power costs.

Historical Generation and Modeled Generation for March Point

Year	March Point 1 (GWh)	March Point 2 (GWh)
1994	689	443
1995	706	466
1996	728	541
1997	610	477
1998	691	495
1999	689	409
2000	705	500
2001	715	504
2002	684	419
9-Year Avg.	691	473
4-Year Avg.	698	457
PSE 2001 RC	643	434
PSE PCORC	741	470
ICNU	692	474

Q. WHAT IS YOUR RECOMMENDATION FOR PROJECTING MARCH POINT'S EXPECTED ENERGY?

A. The ICNU recommendation is to target the March Point generation between the nine and four-year average production values. I believe these values should be used as a range to establish a reasonable normalized production value for March Point. The nine-year average is representative of a significant period of time, and the four-year average captures a complete maintenance cycle for these types of facilities. Added together, the nine-year value is 1,164 gWh for both facilities, and the four-year value is 1,155 gWh.

Although the historical achievement values are 78-87 gWh higher than the values included in Puget's last general rate case (1,077 gWh), these historical values are 47-56 gWh lower than the 1,211 gWh Puget has proposed in this proceeding. Using the AURORA model, ICNU achieved a normalized value of 1,166 gWh for the facilities, which is 45 gWh less than Puget's value in this case. We recommend that the Commission adopt the ICNU value for the rate period. If the Commission adopts this adjustment, it should require Puget to perform an AURORA run with this adjustment included to determine base power costs.

C. <u>GAS PRICE FORECAST</u>

Q. HOW HAS PUGET DETERMINED THE GAS PRICE FORECAST FOR THE RATE YEAR?

A. Puget used the average NYMEX future prices published during the period of September 5, 2003, through September 18, 2003. This period contained ten days of published monthly prices for the rate year. <u>See</u> Exhibit No. ___ (DWS-5C) at DWS/1. The NYMEX monthly average was $4.87/MMBTU for the rate year. Puget then adjusted these values to take into account or recognize market price differentials. To illustrate this step, for the Sumas market hub, Puget adjusted the monthly NYMEX prices downward by an average of [redacted] in recognition of the fact that gas procured at Sumas has traditionally been far below Henry Hub (the NYMEX pricing point). Thus, for Sumas, Puget's average price was [redacted] for the rate year. <u>See</u> Exhibit No. ___ (DWS-5C) at DWS/2.

Q. HOW DO THE GAS PRICES PROPOSED BY PUGET IN THIS PROCEEDING COMPARE WITH THE VALUES FROM PUGET'S LAST GENERAL RATE CASE?

A. The following table compares the values from the last general rate case to the proposed rate year for the Sumas market hub. On average, the Company's projection is [redacted]

PSE Sumas Gas Price Comparison
($/MMBTU)

	[redacted]		[redacted]	[redacted]
Apr-03	[redacted]	Apr-04	[redacted]	[redacted]
May-03	[redacted]	May-04	[redacted]	[redacted]
Jun-03	[redacted]	Jun-04	[redacted]	[redacted]
Jul-03	[redacted]	Jul-04	[redacted]	[redacted]
Aug-03	[redacted]	Aug-04	[redacted]	[redacted]
Sep-03	[redacted]	Sep-04	[redacted]	[redacted]
Oct-02	[redacted]	Oct-04	[redacted]	[redacted]
Nov-02	[redacted]	Nov-04	[redacted]	[redacted]
Dec-02	[redacted]	Dec-04	[redacted]	[redacted]
Jan-03	[redacted]	Jan-05	[redacted]	[redacted]
Feb-03	[redacted]	Feb-05	[redacted]	[redacted]
Mar-03	[redacted]	Mar-05	[redacted]	[redacted]
Avg	[redacted]	Avg	[redacted]	[redacted]

Q. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S METHOD FOR PROJECTING THE GAS PRICES FOR THE RATE YEAR?

A. Yes. I have three significant concerns with the Company's approach: 1) the NYMEX contract volumes do not reflect a robust market for the rate period thereby making the prices highly suspect and uncertain; 2) NYMEX prices take into account near-term circumstances and therefore are not representative of a base year or normalized gas price that is needed for this proceeding; and 3) this is not the method used by the Company to value its portfolio risk.

Q. PLEASE ELABORATE ON YOUR CONCERN REGARDING THE ROBUSTNESS OF THE NYMEX PRICES.

A. The following table summarizes the daily NYMEX contracts traded for the period of October 2003, through March 2005 (the end of the rate year), for the ten days used by Puget. See also Exhibit No. ___ (DWS-5C) at DWS/3.

NYMEX Contract Volumes For September 5-18, 2003

Month	Volume	Percent
October '03	329,659	55%
November	109,684	18%
December	44,460	7%
January '04	37,656	6%
February	17,307	3%
March	21,165	4%
April	12,300	2%
May	6,397	1%
June	3,632	1%
July	2,869	0%
August	2,921	0%
September	2,545	0%
October	2,444	0%
November	1,256	0%
December	1,709	0%
January '05	1,001	0%
February	1,516	0%
March	2,753	0%
Outside Rate Period:	559,931	93%
Rate Period:	41,343	7%

As is always the case, the vast majority of the reported NYMEX activity is for the next month or quarter. Indeed, for this trading period, the October 2003 volume is 55% of the total activity and the fourth quarter of 2003 is 80% of the reported activity. Focusing on the rate period in this proceeding, the contract volumes represent only 7% of the activity, with most of this occurring during the first quarter of the rate year (April 2004 through June 2004). In other words, 93% of the trades during these days were transactions for months outside the rate period. In fact, the trading activity for each of the last 9 months of the rate period is so minimal that it rounds to a 0% value. In my opinion, this is not a meaningful or liquid market—and therefore not a meaningful price—on which to base this critical cost item.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH NYMEX PRICES NOT REFLECTING A NORMALIZED BASE RATE PERIOD VALUE.

A. NYMEX prices will respond or move based upon current events or news far beyond the period that one might logically believe is impacted. Consequently, it is not unusual to see an upward or downward tick in prices for each of the 36 months being reported due to a near-term event. While these movements may be appropriate indicators for the general direction of gas costs, the resulting prices are not appropriate for this proceeding, in which a normalized base gas price is needed instead of a near-term or "next year" price.

Further, there appears to be a growing amount of NYMEX speculative trading as compared to NYMEX hedge trading, which may be having an impact on reported prices. By this I mean that some parties simply are entering into transactions based on their bet on the direction of a price movement instead of entering into transactions to reduce the risk or exposure one has with a particular commodity. If this is the case, this would be another reason why a NYMEX-based price series would not be appropriate for determining the base gas prices in this proceeding.

Q. DOES THE COMPANY EVALUATE ITS RISK EXPOSURE AND DEVELOP HEDGING STRATGIES USING A SINGLE NYMEX-BASED PRICE SERIES?

A. No. Puget evaluates its portfolio risk using an analytical approach that is far more rigorous than simply using a series of NYMEX forward prices. [redacted]

[redacted] It is this type of fundamentals analysis that is needed to determine a base gas price for this proceeding.

Q. HOW DO THE FORWARD GAS PRICES CONTAINED IN THE FUNDAMENTALS REPORT FOR THE RMC COMPARE TO PUGET'S PROPOSAL IN THIS DOCKET?

A. [redacted] The following table compares the median price from the 100 cases to Puget's NYMEX-based proposal for the Sumas market point in addition to also presenting the average price for all 100 scenarios. [redacted]

Forward Price Comparison
Sumas Market Point
($/MMBTU)

	[redacted]	[redacted]	[redacted]	[redacted]
April '04	[redacted]	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]	[redacted]
June	[redacted]	[redacted]	[redacted]	[redacted]
July	[redacted]	[redacted]	[redacted]	[redacted]
August	[redacted]	[redacted]	[redacted]	[redacted]
September	[redacted]	[redacted]	[redacted]	[redacted]
October	[redacted]	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]	[redacted]
January '05	[redacted]	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]	[redacted]
March	[redacted]	[redacted]	[redacted]	[redacted]
Average:	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

The next table compares the Puget PCORC proposal to the median results from the fundamentals analysis for Henry Hub. I have also included an additional column—

taken from page 16 of the fundamentals report—showing the NYMEX prices reported to the RMC at the December 2003 meeting. [redacted]

Forward Price Comparison
Henry Hub
($/MMBTU)

	PSE	[redacted]	[redacted]
	PCORC	[redacted]	[redacted]
April '04	$4.82	[redacted]	[redacted]
May	$4.74	[redacted]	[redacted]
June	$4.74	[redacted]	[redacted]
July	$4.74	[redacted]	[redacted]
August	$4.75	[redacted]	[redacted]
September	$4.74	[redacted]	[redacted]
October	$4.75	[redacted]	[redacted]
November	$4.90	[redacted]	[redacted]
December	$5.06	[redacted]	[redacted]
January '05	$5.15	[redacted]	[redacted]
February	$5.10	[redacted]	[redacted]
March	$4.93	[redacted]	[redacted]
Average:	$4.87	[redacted]	[redacted]

Q. SHOULD PUGET'S PROPOSED GAS PRICES BE USED TO DETERMINE THE BASE POWER COST IN THIS PROCEEDING?

A. No. For all the reasons that I have just discussed, Puget's gas prices—based upon an illiquid NYMEX market—are not a reasonable basis upon which to determine a base cost in this proceeding. Puget should be required to use a fundamentals analysis such as the one that Puget has employed in deriving the electricity price forecast and similar to the one used by Puget in its RMC presentation. A fundamentals model that takes into account basic supply and demand factors, while ignoring short-term market fluctuations or swings, should be used to determine the rate year gas costs.

Q. ARE THERE PUBLICLY AVAILABLE GAS FORECASTS PRODUCED FROM A FUNDAMENTALS MODEL?

A. Yes. Since 1989, the California Energy Commission ("CEC") has produced gas price forecasts using the North American Regional Gas ("NARG") model. In December 2003, the CEC published results from the NARG model in the *Electricity and Natural Gas Assessment Report.* Exhibit No. ___ (DWS-8) shows the results for select market points from the NARG model results used for this publication. I recommend that the CEC Sumas price projection of $3.61/MMBTU be used as a benchmark for the Sumas market point for the rate year. [redacted]

[redacted]

[redacted]

Q. WHY ARE YOU RECOMMENDING USING THE CEC RESULT AS COMPARED TO THE COMPANY'S FUNDAMENTALS FORECAST?

A. I have not had the opportunity to analyze or review the Company's proprietary software tool and the associated inputs. In other words, from my prospective, the model that Puget used for its fundamentals analysis for risk management purposes is a black box. On the other hand, I have been aware of the CEC tool for many years, having analyzed the original FORTRAN source code. Should the Commission determine that the Puget gas price forecast from the December 2003 RMC meeting is more appropriate than ICNU's, this would increase ICNU's recommended revenue requirement by $2.6 million (AURORA comparison of average water year).

Q. PLEASE SUMMARIZE ICNU'S PROPOSED ADJUSTMENTS RELATED TO THE AURORA POWER COST MODEL.

ICNU has proposed adjustments related to the manner in which the Company has improperly modeled the following elements in its power costs in this case: 1) Puget has unnecessarily increased the outage time of Colstrip Unit 3; 2) Puget overstated the generation at the March Point facility; and 3) Puget has used a flawed gas price forecast in the Company's AURORA model. If the Commission were to adopt ICNU's recommendation on all of these issues, it would result in a overall reduction to power costs of approximately $29.5 million, the bulk of which is related to Puget's flawed gas price forecast.

D. CALL OPTIONS

Q. PLEASE EXPLAIN THE CALL OPTION EXPENSE PUGET IS PROPOSING TO INCLUDE IN ITS BASE RATE DETERMINATION.

A. Puget has included approximately $10.5 million in its PCORC filing associated with certain winter peaking options designed to address the risk of extreme temperature variations from November 2004, to February 2005. ICNU recommends that the Commission disallow $9.8 million of this expense because it is excessive and these options are not a cost effective manner of addressing weather risk.

Exhibit No. ___ (WAG-16) contains a listing by FERC account and resource (or contract) of the power costs Puget is proposing to recover in the three columns under the PCORC acronym. Towards the bottom of this exhibit, there is an account 555 row simply entitled "Capacity," for which Puget has included $10,490,000 in its PCORC filing. This $10,490,000 represents the level of option costs (really an upfront reservation charge) that Puget is proposing to include in its base rate determination. This is an excessive amount for these peaking options given the actual risk of extreme weather events that Puget faces.

Q. HOW HAS PUGET CALCULATED THE PRICE OF THESE PEAKING OPTIONS?

A. Exhibit No. ___ (DWS-9C) replicates the assumptions and calculations employed by Puget to arrive at the $10.5 million value. Lines 1 and 2 of this exhibit show the only costs incurred to date for the rate year from the purchase of a single 50 MW option at a reservation price of [redacted] Line 3 indicates that Puget expects to have a remaining unfilled capacity of 2,729 MW-months based upon the extreme temperatures shown in line 4. These temperatures are far colder than the 23 F expected peak hour temperature value. Lines 8 through 10 show the costs assumed by Puget for obtaining call options for the remaining unfilled extreme peak need based upon the assumed prices shown in lines 6 and 7. Puget assumed it could obtain the first 200 MW each month at a price equivalent to [redacted] or slightly higher than the actual price it had incurred for the first 50 MWs of need. Puget valued the remaining unfilled need at an equivalent price [redacted] higher than the cost of the first 50 MW actually procured.

Q. WHAT WAS THE BASIS FOR PUGET'S ASSUMED PRICES FOR THE UNFILLED NEED?

A. The prices used for the unfilled extreme need were derived from an informal solicitation process summarized in workpapers of Mr. William Gaines that are included as Exhibit No. ___ (DWS-10C). Page 1 of Exhibit No. ___ (DWS-10C) indicates that this informal solicitation process resulted in bids that were far above the historical purchases in prior years.

Q. DOES PUGET HAVE ADEQUATE WINTER PEAKING RESOURCES UNDER NORMAL WEATHER CONDITIONS FOR THE RATE YEAR?

A. Under normal weather conditions, Puget has sufficient capacity for three of the four winter months. There is a projected 256 MW deficit in the month of January.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO INCLUDE $10.5 MILLION OF PEAKING OPTIONS IN THE BASE POWER RATE?

A. No. I disagree with the Company's proposal for many reasons. The effective price of the option energy is far too expensive to be cost effective. The Company's past procurement of options has not come close to the level included in the current charges. Furthermore, the Company appears to be pursuing other hedging strategies that do not require the substantial reservation charges included in the peaking options. Finally, the institution of the PCA should handle the very limited risk that the peaking options are intended to address instead of including this cost in the base power charge.

Q. WHAT IS THE EFFECTIVE COST OF THE ENERGY OBTAINED UNDER THESE OPTIONS?

A. The effective cost will be dependent upon the amount of energy that is actually procured under the option agreements, which in turn is dependent upon the weather that will be experienced during the upcoming winter season. The agreements typically are structured with a reservation charge that is paid up front, which accounts for Puget's proposed $10.5 million cost in this proceeding, and then a strike price when the energy actually is needed. Based upon the solicitation results, the strike price is generally around [redacted]. Exhibit No. ___ (DWS-10C) ay DWS/5. Another significant feature of the call options is that Puget must give daily notice and take the block of power at a flat delivery rate for the entire 16-hour peak period. The amount of options that Puget currently is proposing to include in rates would allow the procurement of [redacted] of on-peak power during the four winter months. This is a substantial sum.

Q. DOES PUGET HAVE A NEED FOR THIS AMOUNT OF ON-PEAK ENERGY?

A. No. To need this amount of energy, each and every day of the winter season would have to average ten degrees colder than normal. By way of comparison, for the recent cold snap that occurred from December 1, 2003, to January 21, 2004, there were only five days that equaled or exceeded 10 heating degree days ("HDD") colder than normal, as measured at Sea-Tac. For the entire period, the aggregate HDDs were actually 14 less (or warmer) than normal.

In Olympia, this extreme cold snap included two days where the lowest hourly temperature was actually below the 12 degree extreme temperature used by Puget for December. The extreme weather in Olympia from January 3, 2004, through January 6, 2004 was 57 HDD above normal. If this extreme weather had occurred throughout Puget's service territory, the Company would have needed only an additional [redacted]. This is only [redacted] of the energy amount that Puget could acquire under the options that the Company proposes to include in rates in this proceeding.

The following table depicts the effective cost of power under the proposed options at various levels of need.

**Effective Cost of PSE's
Option Energy**

MWh Need	Reservation Charge ($/MWh)	[redacted]	Effective [redacted]	[redacted]
10,000	$1,049	[redacted]	[redacted]	[redacted]
20,000	$525	[redacted]	[redacted]	[redacted]
30,000	$350	[redacted]	[redacted]	[redacted]
40,000	$262	[redacted]	[redacted]	[redacted]
50,000	$210	[redacted]	[redacted]	[redacted]
60,000	$175	[redacted]	[redacted]	[redacted]
70,000	$150	[redacted]	[redacted]	[redacted]
80,000	$131	[redacted]	[redacted]	[redacted]
90,000	$117	[redacted]	[redacted]	[redacted]
100,000	$105	[redacted]	[redacted]	[redacted]
200,000	$52	[redacted]	[redacted]	[redacted]
300,000	$35	[redacted]	[redacted]	[redacted]
400,000	$26	[redacted]	[redacted]	[redacted]
500,000	$21	[redacted]	[redacted]	[redacted]
600,000	$17	[redacted]	[redacted]	[redacted]
700,000	$15	[redacted]	[redacted]	[redacted]
800,000	$13	[redacted]	[redacted]	[redacted]
900,000	$12	[redacted]	[redacted]	[redacted]
1,000,000	$10	[redacted]	[redacted]	[redacted]
1,100,000	$10	[redacted]	[redacted]	[redacted]
1,172,560	$9	[redacted]	[redacted]	[redacted]

Based upon the example of [redacted] of need due to the recent extreme weather conditions, the effective cost under the proposed option strategy would be over [redacted]. During the January cold snap, the Mid-Columbia daily prices were only around $50-60/MWh. This table shows that for the very limited, short, low temperature excursions experienced in the Pacific Northwest, having a substantial amount of daily call options is not cost effective.

Q. HAS PUGET PERFORMED AN ANALYSIS ON THE COST EFFECTIVENESS OF DAILY CALL OPTIONS THAT PRODUCED SIMILAR RESULTS?

A. Yes. Exhibit No. ___ (DWS-11C) contains a presentation to the RMC on May 1, 2003, regarding the need to acquire additional call options for the 2003 winter. The analysis was done using the Company's risk assessment software (KW3000) using 100 scenarios. The minutes from that meeting contain the following recommendation:

[redacted]

Exhibit No. ___ (DWS-12C) at DWS/2.

Q. DOES IT APPEAR THAT THE COMPANY HAS FOLLOWED THROUGH WITH THIS RECOMMENDATION?

A. Yes. Since the recommendation was made to the RMC, Puget has only procured 50 MW of daily options and focused more on exchange power arrangements to achieve winter reliability needs. The last rate case stipulation adopted $11.2 million of reservation costs for option purchases in 2002. However, the Company only expended [redacted] for the winter of 2003/2004 and all of this cost was incurred prior to the RMC meeting. For the winter of 2002/2003, the Company only expended $1.8 million. Finally, Exhibit No. ___ (DWS-13HC) contains a [redacted] This hedging strategy does not require the costly reservation charges associated with daily call options since the premiums for the put and call generally offset each other.

Q. WHAT AMOUNT OF MONEY DO YOU RECOMMEND THE COMMISSION INCLUDE FOR TEMPERATURE-RELATED HEDGING COST IN THE BASE POWER RATE?

A. It is difficult to propose a recommendation because the Company was not forthcoming in its direct case with its disenchantment with respect to the cost effectiveness of daily call options, and it did not reveal the actual hedging instruments that it was considering for the rate year. We do know that the Company has procured 50 MW at a cost of [redacted]. I would recommend adding to this amount no more than an additional 250 MW of January call options, and valuing these options at the [redacted] price of [redacted]. This would cover the January deficit at a cost of [redacted]. Taken together, this provides a fund of approximately [redacted]—a value comparable to actual expenditures for this cost item— with which to pursue more cost effective strategies. Adoption of this recommendation lowers the revenue requirement the Company is seeking by $9.8 million. Any additional costs the Company may incur for meeting the actual winter season peaks should be passed through the PCA.

E. TENASKA

Q. PLEASE PROVIDE A BRIEF HISTORY OF THE TENASKA POWER PURCHASE AGREEMENT.

A. The original power purchase agreement between Puget and Tenaska was signed in March 1991. [redacted] The Commission deemed the price series to be imprudent in docket numbers UE-920433, UE-920499 and UE-921262 due to Puget's failure to value dispatchability.

> The Commission finds that, for March Point Phase II and Tenaska contracts, Puget's failure to factor in the value of dispatchability caused Puget to pay too much for the contracts. For ratemaking purposes, the portion of the price the company can recover from ratepayers will be adjusted. Future ratemaking treatment for these contracts should reflect the disallowances as follows for the two contracts: 3% of the net contract charge for March Point Phase II, and 1.2% of net contract charge for Tenaska.

WUTC v. Puget Sound Power & Light Co., WUTC Docket Nos. UE-920433, UE-920499 and UE-921262, Nineteenth Supplemental Order at 32 (Sept. 27, 1994). Subsequently, in docket number UE-971619, Puget sought an accounting order for approval of the ratemaking and accounting treatment associated with the buy out of the Tenaska fuel supply contract. The Commission approved the Company's proposal to create a regulatory asset associated with the cost of the buy out for subsequent recovery in rates. However, the Commission specifically reserved the right to review the reasonableness of the Company's actions in relation to the contract in the future:

> The Company's actions in purchasing the gas sales contract, managing the cost of gas, and restructuring the power purchase agreement is subject to review in future rate proceedings; the Company bears the burden of proof in any such proceeding regarding these matters. Any costs determined to be unreasonable or imprudent in such proceedings are subject to disallowance.

Re Puget, WUTC Docket No. UE-971619, Order at 6 (Dec. 15, 1997). Thus, there is an ongoing obligation for the Company to demonstrate the reasonableness of the cost associated with the Tenaska facility.

Q. WHAT COST IS PUGET SEEKING TO RECOVER FOR TENASKA IN THIS PROCEEDING?

A. In the current filing, PSE is seeking an effective cost for energy from Tenaska of

$121.7/MWh including displacement costs. The effective base power rate that PSE is seeking under the reformed contract excluding displacement is $102/MWh. This value is composed of a base contract rate of $72/MWh, plus an amortization payment on the regulatory asset of $12/MWh and a return on the regulatory asset of $18/MWh.

As previously noted, under the original Tenaska contract, the effective base power rate (assuming no displacement) would have been [redacted] for the April 2004 through March 2005 rate year. Further, the price under the Commission's disallowance of 1.2% of all payments, would have made the authorized price [redacted] for the rate period. Consequently, the reformed contract is increasing the power cost sought by Puget in this proceeding by [redacted] as compared to the original contract cost. After adjustment for the Commission's 1.2% disallowance, the increase in cost is [redacted].

Q. HAVE RATEPAYERS BENEFITED FROM THE REFORMATION OF THE TENASKA CONTRACT?

A. No. The analysis done to support the reformation of the contract reflected a net present value ("NPV") after tax saving of [redacted]. <u>See</u> Exhibit No. ___ (DWS-14C) at DWS/1. This value included a modest NPV ratepayer cost of [redacted] over the years 1998 through 2001, followed by a substantial NPV benefit of [redacted] for 2002 through 2011. For the period of 1998 through 2003, Puget projected a NPV benefit of [redacted].

I have updated the analysis done to support the buy out of the gas contract and included it in Exhibit No. ___ (DWS-14C) at DWS/2. The analysis modified the gas prices to reflect historical prices through 2003 coupled with the CEC NARG projected prices for Sumas for the remaining years of the contract, which are presented in Exhibit No. ___ (DWS-8). This analysis shows an NPV cost to ratepayers of [redacted] from

1998 through 2003. This obviously is a substantial difference from Puget's projected [redacted] benefit for this period. For the remaining term of the contract (2004 through 2011), the update shows the limited net present value to the Company's ratepayers does not offset the real costs that have been borne by ratepayers to date. In fact, the overall NPV is actually a ratepayer cost of [redacted].

Q. HOW HAS THE SUBSTANTIAL BENEFIT PROJECTED BY PUGET AT THE TIME IT REFORMED THE CONTRACT RESULTED IN A COST TO CUSTOMERS?

A. The original analysis done by Puget relied upon long-term gas price quotes from a number of providers as shown in the last several rows of Exhibit No. ___ (DWS-14C) at DWS/1. However, since the buy out, Puget has primarily relied upon spot market purchases for the procurement of gas. <u>See</u> Exhibit No. ___ (DWS-15). Accordingly, as the actual prices have surpassed the price quotes, the projected ratepayer benefit from reforming the contract has turned into substantial ratepayer cost. Simply put, Puget failed to enter into any kind of hedging arrangement to lock-in the benefit that could have occurred in reforming the contract. If Puget had been able to achieve the gas prices that the Company assumed at the time of the gas contract buy out for the rate year [redacted] the overall revenue requirement currently proposed by Puget would have been [redacted] (AURORA single water year run; PSE inputs).

Q. ARE YOU AWARE OF WHETHER PUGET CONSIDERED HEDING ITS GAS EXPOSURE AFTER THE BUY OUT OF THE TENASKA GAS CONTRACT?

A. An RMC presentation document, dated December 13, 2001, entitled Tenaska Hedge Strategy includes the recommendation to buy 50,000 MMBTU/day for Tenaska for 2003-2011 given the bearish market. This quantity of gas would be sufficient to power the plant; however, Puget apparently did not implement this strategy.

Q. WHAT IS ICNU'S PROPOSAL FOR ADDRESSING THIS FAILURE?

A. There are three approaches that could be considered. The Commission could simply limit the recovery of power costs associated with Tenaska to the original contract value adjusted for the Commission's disallowance. This would reduce the revenue increase sought by PSE in this proceeding by $25.5 million. A second approach would simply be to write off the regulatory asset and remove it from rate base, because it has created no ratepayer value. In the current proceeding, eliminating the revenue requirement associated with the asset reduces the revenue requirement by $40.3 million. A third approach would impute the gas cost savings used in the reformation analysis. In other words, the gas price used for Tenaska in this proceeding would be $1.93/MMBTU. This would reduce the revenue requirement by $29.0 million using all of the ICNU recommendations. ICNU recommends the second approach in recognition of the fact that the ratepayers have incurred a net loss from the payment of the revenue requirement associated with the regulatory asset for a number of years.

Q. DID YOU CONSIDER THE GREATER DISPATCH FLEXIBILITY PUGET GAINED UNDER THE BUY OUT?

A. Yes. I recognize that Puget did gain greater dispatch flexibility under the reformed agreement. The difficulty, however, is assigning a value to this right. The value in any year can vary dramatically based upon hydro conditions and market prices over the term of the contract. To properly assess this value, one would need to do a risk assessment taking into account a host of water years and gas prices. There simply was not enough time to undertake such an endeavor given the time period for filing testimony. In response to Staff DR No. 86, Puget performed an analysis to determine the value of dispatchability based upon a single average water year using its proposed gas prices and resulting electricity prices. This analysis indicates a dispatchability value of [redacted] for the rate year. I do not believe that this is the correct approach to value this right. Performing a similar analysis using all the ICNU recommendations for resource availability, gas costs, and resulting market prices produced a negligible value for the rate year since gas-fired units were on the margin the vast majority of the time. If the Commission believes an adjustment is warranted, I would recommend using the 1.2% dispatchability value adopted by the Commission in Docket UE-920433, UE-920499 and UE-921262. Under the ICNU recommendations, this would result in a revenue requirement increase of $1.4 million.

F. RATE SPREAD

Q. HAVE YOU PREPARED AN ANALYSIS SHOWING THE CLASS SPECIFIC DECREASES WITH THE ADOPTION OF THE ICNU RECOMMENDATIONS?

A. Yes. Exhibit No. ___ (DWS-16) shows the class impacts from the adoption of the ICNU revenue requirement recommendations. In preparing this exhibit, the exact cost allocation and rate spread approach employed by the Company was used. We simply modified the overall rate increase amount proposed by Puget to the recommended decrease level recommended by ICNU.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

Exhibit No. ___ (DWS-2)

Qualifications of

Donald W. Schoenbeck

Exhibit No. ___ (DWS-3C)

Colstrip Availability

(Workpapers of

William Gaines

38, 40 and 41)

Redacted

Exhibit No. ___ (DWS-4)

March Point Generation

(PSE Responses to

ICNU Data Requests

2.16, 2.18, and 4.09)

Exhibit No. ___ (DWS-5C)

NYMEX Gas Forecast

Redacted

Puget Sound Energy
Docket UE-031725 - Power Cost Only
PSE Forecast - NYMEX HENRY HUB

	9/5/03	9/8/03	9/9/03	9/10/03	9/11/03	9/12/03	9/15/03	9/16/03	9/17/03	9/18/03	Average:
January '04	5.447	5.354	5.392	5.576	5.432	5.475	5.410	5.367	5.328	5.214	5.40
February	5.395	5.304	5.335	5.508	5.372	5.412	5.353	5.310	5.278	5.169	5.34
March	5.295	5.209	5.237	5.398	5.268	5.308	5.258	5.215	5.183	5.076	5.24
April	4.863	4.789	4.827	4.928	4.843	4.873	4.840	4.795	4.778	4.701	4.82
May	4.775	4.704	4.740	4.835	4.754	4.783	4.750	4.705	4.688	4.613	4.73
June	4.780	4.711	4.745	4.835	4.761	4.790	4.760	4.715	4.703	4.633	4.74
July	4.780	4.713	4.747	4.825	4.756	4.785	4.761	4.712	4.708	4.638	4.74
August	4.785	4.721	4.755	4.825	4.761	4.790	4.761	4.715	4.711	4.641	4.75
September	4.760	4.706	4.750	4.815	4.751	4.780	4.751	4.700	4.705	4.639	4.74
October	4.780	4.721	4.755	4.815	4.761	4.790	4.761	4.710	4.710	4.654	4.75
November	4.935	4.876	4.908	4.965	4.916	4.945	4.921	4.867	4.862	4.816	4.90
December	5.089	5.030	5.059	5.115	5.071	5.105	5.086	5.030	5.020	4.984	5.06
January '05	5.180	5.121	5.145	5.185	5.151	5.190	5.176	5.120	5.125	5.084	5.15
February	5.130	5.071	5.095	5.135	5.106	5.135	5.121	5.065	5.070	5.044	5.10
March	4.965	4.906	4.925	4.955	4.946	4.965	4.961	4.907	4.915	4.894	4.93
April	4.635	4.588	4.607	4.637	4.628	4.647	4.641	4.579	4.590	4.574	4.61
May	4.549	4.502	4.521	4.542	4.533	4.547	4.536	4.479	4.495	4.479	4.52
June	4.547	4.506	4.525	4.542	4.528	4.537	4.526	4.469	4.485	4.469	4.51
July	4.555	4.516	4.535	4.550	4.531	4.540	4.529	4.473	4.495	4.485	4.52
August	4.555	4.516	4.535	4.545	4.526	4.530	4.519	4.463	4.485	4.475	4.51
September	4.550	4.516	4.535	4.545	4.526	4.530	4.519	4.463	4.485	4.475	4.51
October	4.590	4.556	4.570	4.580	4.561	4.565	4.569	4.508	4.530	4.520	4.55
November	4.775	4.742	4.758	4.768	4.749	4.753	4.774	4.698	4.720	4.710	4.74
December	4.950	4.927	4.951	4.961	4.942	4.946	4.954	4.878	4.900	4.890	4.93
2004 Avg											**4.93**
2005 Avg											**4.72**
Rate Year											**4.87**

Exhibit No. ___ (DWS-5C)
DWS/1

Puget Sound Energy
Docket UE-031725 - Power Cost Only

NYMEX Contract Volumes

	Total	Percent	9/5/2003	9/8/2003	9/9/2003	9/10/2003	9/11/2003	9/12/2003	9/15/2003	9/16/2003	9/17/2003	9/18/2003
October '03	329,659	55%	22,623	49,463	17,243	34,795	29,867	50,137	37,760	38,835	27,325	21,611
November	109,684	18%	7,346	12,397	6,504	10,721	9,784	17,399	12,688	14,675	8,432	9,738
December	44,460	7%	4,838	7,776	5,537	3,783	3,022	4,107	5,078	4,138	2,303	3,878
January '04	37,656	6%	5,328	6,840	2,617	2,890	1,938	3,950	3,276	4,127	3,287	3,403
February	17,307	3%	1,579	2,734	2,239	1,319	1,028	2,548	2,260	1,087	1,044	1,469
March	21,165	4%	2,978	2,702	1,284	1,413	1,405	2,871	2,159	2,049	1,857	2,447
April	12,300	2%	2,235	1,305	395	886	442	2,203	1,067	1,183	1,423	1,161
May	6,397	1%	614	1,238	637	708	271	725	437	203	1,174	390
June	3,632	1%	143	641	273	178	307	351	173	454	808	304
July	2,869	0%	95	373	393	121	334	380	165	235	433	340
August	2,921	0%	154	213	140	196	459	270	330	168	333	658
September	2,545	0%	57	53	400	200	322	216	481	326	366	124
October	2,444	0%	497	102	273	195	247	313	289	227	223	78
November	1,256	0%	161	177	67	37	117	386	73	45	149	44
December	1,709	0%	189	254	322	60	140	179	228	163	139	35
January '05	1,001	0%	87	103	28	18	125	45	168	63	338	26
February	1,516	0%	75	92	128	101	406	45	156	209	275	29
March	2,753	0%	412	468	48	28	910	345	329	127	66	20
Total	601,274											
Outside Rate Period	559,931	93%										
Rate Period	41,343	7%										

Exhibit No. ___ (DWS-6C)

Risk Assessment Description

(PSE Response to

ICNU

Data Request 4.07)

Redacted

Exhibit No. ___ (DWS-7C)

RMC

Market Fundamentals

Report

December 2003

(Part of PSE response to ICNU 3.15)

Redacted

Exhibit No. ___ (DWS-8)

CEC NARG Model

Fundamental Gas Forecast

Exhibit No. ___ (DWS-9C)

Summary of

PSE Call Option

Calculation

Redacted

Exhibit No. ___ (DWS-10C)

PSE Call Option

Price Support

(Workpapers of

William Gaines

202 through 207)

Redacted

Exhibit No. ___ (DWS-11C)

RMC Presentation

Update on Winter Peaking

Capacity Purchases

1 May 2003

(Part of PSE Response to

ICNU 3.14)

Redacted

Exhibit No. ___ (DWS-12C)

RMC

Meeting Minutes

Of

May 1, 2003

(Part of PSE Response to

ICNU 2.06

Redacted

Exhibit No. ___ (DWS-13HC)

RMC

Hedging Margin Risk

December 18, 2003

(Part of PSE Response

to ICNU 3.15)

Redacted

Exhibit No. ___ (DWS-14C)

Tenaska

Exhibit B

Buyout Update

Redacted

Exhibit No. ___ (DWS-15)

Tenaska Gas Management

(Non-confidential portion of PSE's

response to ICNU 2.06)

EXHIBIT No. ___ (DWS-16)

ICNU

RATE SPREAD

RECOMMENDATION