EXHIBIT NO. ___(WJE-7HC)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: W. JAMES ELSEA

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____**

SIXTH EXHIBIT (HIGHLY CONFIDENTIAL) TO THE
PREFILED DIRECT TESTIMONY OF
W. JAMES ELSEA
ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED
VERSION

FEBRUARY 15, 2006

Exhibit 1

Resource Need, Portfolio and Market Benefits

Public Utility District No. 1 of Chelan County

Power Sales Agreement
and
Transmission Agreement

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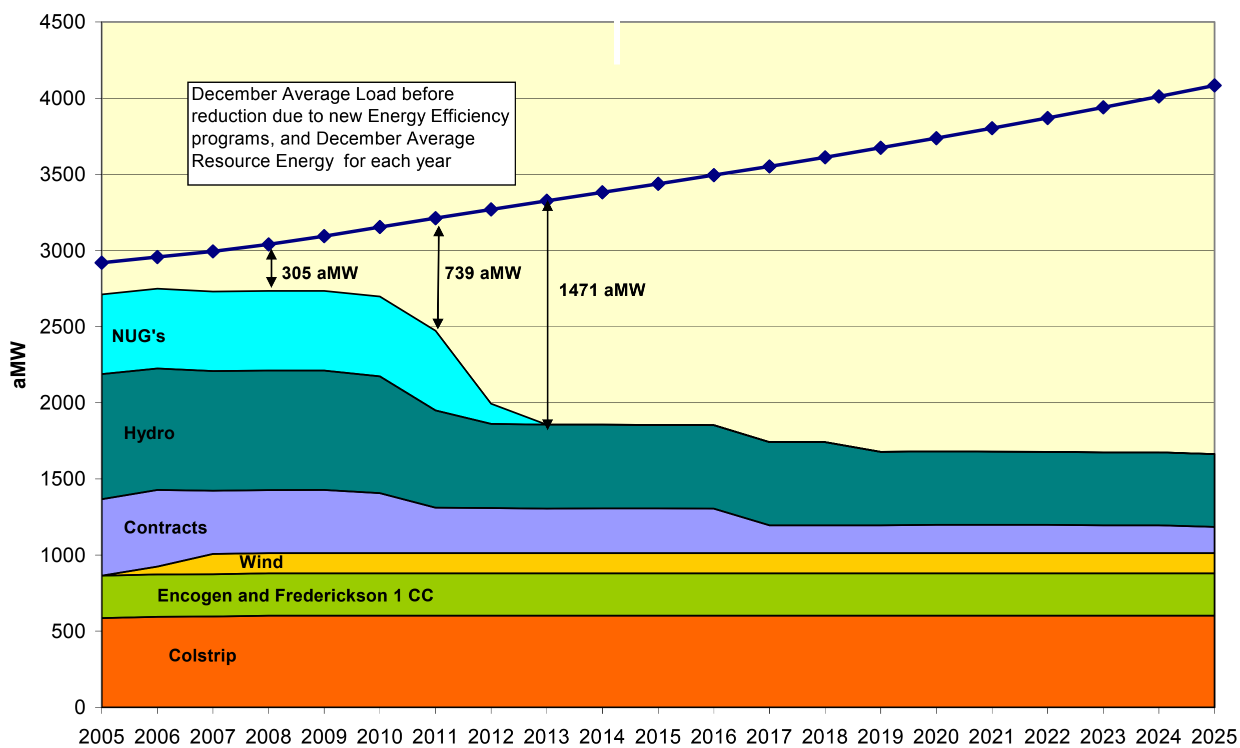
I. Need for Resources

PSE's 2005 Least Cost Plan ("LCP") was published in April 2005 as part of PSE's efforts to analyze and document its projected load and corresponding need for additional resources. The LCP identified need for additional electric energy resources based upon the "B2" planning standard as most recently adopted by PSE's Board of Directors. That standard requires that PSE plan energy supply additions to meet its highest deficit month. PSE's increasing resource need is driven both by forecast load growth and loss of existing generating resources. Over the period from 2008 through 2013, the "B2" planning deficit rises from 305 aMW to 1,471 aMW. The 2005 LCP Load Resource-Resource balance is shown in the following graph.

2005 LCP, 2006-2025 Load-Resource Balance



For planning purposes, PSE assumed that its contracts with the District would be renewed in the aggregate at half of their existing levels. The proposed transaction improves upon that assumption with respect to Chelan by 39 aMW. In addition, PSE's conservation efforts are expected to reduce the 2013 deficit by 195 aMW, resulting in a need for 1,237 aMW of additional supply resources to be acquired (via outright ownership or power purchase agreements) in order for PSE to meet its planning standard by 2013.

II. Evaluation Methods and Results Summary

The financial benefits of the proposed Power Sales Agreement (the "Agreement") were evaluated using three approaches.

A. **Replacement Cost.** First, the proposed Agreement was evaluated relative to the Company's replacement cost estimates for power purchased from the market, including capacity and ancillary service characteristics similar to the supply of power from the Chelan Hydro System.

   The expected levelized cost of the proposed Agreement, in 2006 dollars, is $[redacted] per MWh, approximately $[redacted] per MWh less than the estimated replacement cost, including ancillary services, of $[redacted].

B. **Portfolio Evaluation.** Second, the costs and benefits of the proposed Agreement to PSE's overall resource portfolio were evaluated using the Company's 20-year Portfolio Screening Model that is used to evaluate all potential resource acquisition candidates.

   i. Static Analysis Reference Price Scenario: PSE's portfolio costs with the proposed Agreement are more than $359 million lower, on an NPV basis, than a portfolio with an assumed mix of contracts, gas and coal generation. The portfolio savings of the proposed Agreement, on a nominal dollar basis, are more than $1.2 billion dollars.

ii. Static Analysis Low Gas Price Scenario: The portfolio analysis was also conducted under assumptions of lower gas and power prices. PSE's portfolio costs with the proposed Agreement are more than $300 million lower, on an NPV basis, than a portfolio with assumed mix of contracts, gas and coal generation. The portfolio savings of the proposed Agreement, on a nominal dollar basis, are more than $1 billion dollars.

iii. Monte Carlo (Dynamic) Analysis Reference Price Scenario: PSE's portfolio cost reduction is more than $325 million, on an NPV basis. The savings calculated under dynamic analysis are less than the savings calculated using static analysis due to the additional natural gas-fired plants assumed without the Chelan Agreement. Under dynamic analysis, a few of the Monte Carlo trials produce significant sales margins from the assumed replacement gas plants.

C. **Hydro Generation Availability.** Third, the impact of weather on the availability of hydro generation was evaluated using the 70 historical water years from 1929 through 1998.

The variability of the 20-year levelized cost, resulting from hydro conditions, ranges from a low of $[redacted] / MWh to a high of $[redacted] / MWh in the lowest 20-year period. The lowest year on record was the water-year ending July 1937, producing generation that was about 80% of the 70-year average. If the Chelan Power System produced generation equal to 80% of its 70-year average for each of the Agreement's 20 years (an extremely unlikely set of events), the expected price would increase from about $[redacted] to about $[redacted] / MWh. Whether $[redacted] or $[redacted] per MWh, the extreme hydro generation cases are less than the forecast $[redacted] per MWh replacement cost.

Each of these evaluations is discussed below.

III. Replacement Cost Evaluation

The replacement cost is based on a synthetic hydro resource, calculated using the October 2005 Reference Case (Base) Aurora-based long-term forecast of short-term energy prices at the Mid-C Hub and procurement costs related to ancillary services, including load following and regulation, spinning and non-spinning reserves, as well as storage, credit premiums, and capacity charges.

Capacity associated with the proposed Agreement is about two times average energy. In other words, replacing energy only yields half of the capacity provided by the proposed Agreement. To account for this, capacity value was added to the replacement cost using the on-peak to off-peak AURORA price spreads as modified and informed by PSE's forward market spread, dated October 27, 2005. The AURORA price ends in year 2025 and was extended through 2031, the final year of the proposed Agreement, using a 2.5% escalation factor.

The levelized cost of this synthetic hydro resource is $[redacted] per MWh.

The replacement power price forecast for such a synthetic hydro resource is compared to the projected unit costs for the proposed Agreement in the following graph. The relative high cost of the proposed Agreement in 2011 is caused by a full year of imputed debt cost divided by two months of energy. The price of the proposed Agreement declines in 2031 when PSE's $18.5 million Prepayment (paid in 2011) is credited against PSE's share of Chelan Power System costs.

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The underlying gas price forecasts used in the AURORA (October 2005) Reference Case and Low Gas case are shown in the following graphs. The Reference (Base) case assumes forward market prices through 2011 and then assumes the CERA "Rearview Mirror" forecast from 2012 through 2020. The Low Gas case assumes forward market prices through 2007 and then assumes the CERA "World in Turmoil" forecast from 2008 through 2020.

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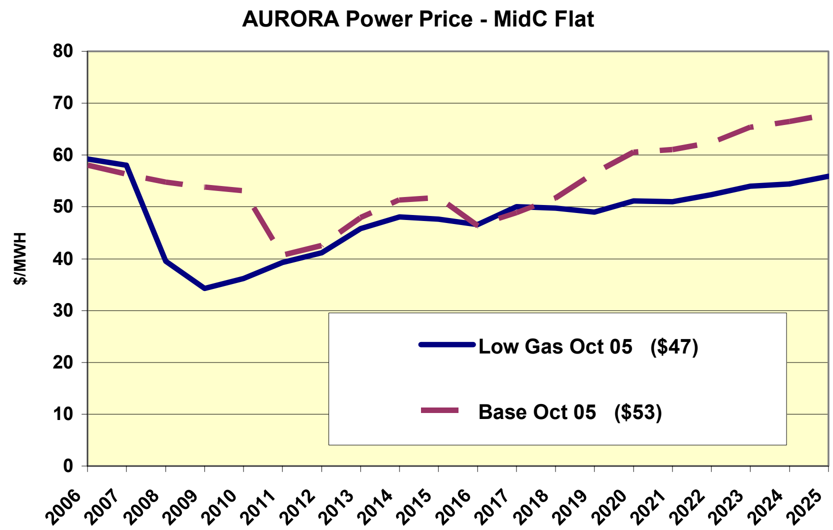

IV. Portfolio Evaluation

Costs and benefits of the proposed Agreement to PSE's overall resource portfolio were evaluated using the Company's 20-year Portfolio Screening Model (PSM) that is used to evaluate all potential resource acquisition candidates. The PSM is an Excel-based computer simulation model that can be used to evaluate cost and risk for a wide variety of resource alternatives and portfolio strategies. Because the PSM ends in 2025, the end effects, through 2031, of the proposed Agreement were evaluated using a trend of the market values in the last three years of the Agreement. This is a similar approach to the logic used to evaluate the end effects of a generation plant that has a useful life longer than the PSM study length.

The Portfolio Costs shown below are for PSE's portfolios, both with and without the proposed Chelan Agreement. Portfolio costs include the variable fuel costs of PSE's existing portfolio, fixed and variable costs of assumed new resources, market purchases when the portfolio is deficit in any hour, market sales when the portfolio is surplus, and end effects for any generation resources with a useful life longer than the term of the model.

- Static Analysis Reference Price Scenario: Portfolio comparison indicates that the proposed Agreement reduces portfolio costs by over $359 million (PV 2006$), and by over $1.2 billion in nominal dollars.

Static Reference Case	With Chelan	Without Chelan	(Savings) Cost
20-year NPV	$7,745,109	$8,104,841	($359,732)
20-year Nominal	$19,669,699	$20,936,768	($1,267,070)

- Static Analysis Low Gas Price Scenario: Portfolio comparison indicates that the proposed Agreement reduces portfolio costs by over $300 million (PV 2006$). The low gas price scenario was run to test the viability of the Agreement under conditions when gas prices fell below $4.00 per mmbtu at the start of the Agreement and spot power prices were also proportionally lower. The following table shows that the portfolio savings are robust even under conditions of lower market prices for power and gas.

Static Low Gas Case	With Chelan	Without Chelan	(Savings) Cost
20-year NPV	$7,396,014	$7,697,896	($301,882)
20-year Nominal	$19,467,922	$20,518,932	($1,051,010)

- Monte Carlo (Dynamic) Analysis: Portfolio comparison indicates that the proposed Agreement reduces portfolio costs by over $325 million and slightly reduces the risk. Under the Monte Carlo assumptions with gas and power price volatility, the natural gas plants dispatch more than they do in the static analysis and create market sales that reduce the portfolio cost. The savings calculated under dynamic analysis are lower than savings calculated using static analysis due to the additional natural gas fired plants assumed without the Chelan Agreement. Under dynamic analysis, a few of the Monte Carlo trials produce significant sales margins from the assumed replacement gas plants.

20 Year Expected Cost - NPV

	With Chelan	Without Chelan	Difference
Trials	100	100	0
Mean	$7,514,353	$7,839,456	($325,103)
Range Minimum	$6,308,449	$6,590,805	($282,357)
Range Maximum	$8,790,685	$9,151,098	($360,413)
20-year Risk	5.82%	5.82%	-0.000%
Average annual risk	40%	41%	-1.0%

Two risk measures are presented and show a slight reduction in uncertainty of portfolio costs with the addition of the proposed Agreement. The first, a 20-year risk measure, is the coefficient of variation (standard deviation divided by mean) of the 100 trials of 20-year NPV portfolio costs. The 20-year risk is lower than the average annual risk due to the probability that there will be high cost and low cost years averaged into the 20-year expected cost. The annual average risk represents the year-to-year portfolio cost changes expected over time. The annual average risk is calculated as the standard deviation of the year-to-year portfolio cost changes averaged over the 100 Monte Carlo trials. The reader is reminded that portfolio costs include the variable cost of PSE's existing fleet, along with the fixed and variable cost of resource additions. Portfolio costs do not include the fixed costs of PSE's existing portfolio. The risk measures presented above show that even with the addition of the hydroelectric generation variability due to the Chelan Agreement, the overall risk of the portfolio is slightly reduced.

V. Hydro Generation Variability

To evaluate the impact of hydro variability on Chelan Power System costs, PSE assumed power generation at Rocky Reach and Rock Island as forecast in Final Regulation FR06, developed by the NWPP for 70 water years from 1929 through 1998. The following four questions were evaluated:

Hydro Question #1. What is the variability of the 20-year levelized cost?

The variability of the 20-year levelized cost ranges from a low of $[redacted] / MWh to a high of $[redacted] / MWh. This distribution has a mean of $[redacted] / MWh and a coefficient of variation of 4.7% ($[redacted] / MWh). [Note that the mean of the Monte Carlo distribution is $[redacted], which is slightly higher than the $[redacted] / MWh calculated without Monte Carlo.] The total levelized cost for the proposed Agreement was calculated as the sum of the actual contract costs plus the cost of imputed debt imposed by the Standard and Poor's credit rating agency. The total levelized cost includes about $[redacted] / MWh of imputed debt costs, resulting in a balance of contract operating costs of approximately $[redacted] / MWh.

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PSE used a Monte Carlo simulation to evaluate the range of levelized cost. The simulation selects a water year between 1929 and 1998 as the first year of the contract. The next 19 years of the contract are modeled using the subsequent 19 water years to the year selected. If the first year selected is greater than 1979, then the 19 years is comprised of the remaining years through 1998 and then assumes a rollover back to 1929 for the remaining year(s).

The generation in the 70 individual water years was divided by the average to get a distribution of generation with a mean of 1.00. Minimum generation during the 70-year period was 80% of the average and occurs in water-year 1937. The following table presents statistics of the generation in FR06:

FR06 Normalized Generation at Rocky Reach and Rock Island

Average	1.000
Median	0.991
Maximum	1.255
Minimum (WY 1937)	0.803
Standard deviation	0.127

Hydro Question #2. What is the cost variability in a single year due to hydro variability?

The graph and table below depict the range of costs expected for 2013, the first full single year with output from both Rocky Reach and Rock Island. As expected, the range is wider for a single year than for a series of 20 years.

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Hydro Question #3. What is the forecast cost of power in the extremely unlikely event that all 20 years were equivalent to 1937, the lowest generation year in Final Regulation FR06?

The Final Regulation FR06 forecast for WY-1937 was 80% of average. If Chelan Power System generation was equal to 80% of average for each of the 20-years during the term of the proposed Agreement (an extremely unlikely set of events), the expected price would increase from $[redacted] to about $[redacted] / MWh. This cost is over $[redacted] / MWh less than the forecast market value of $[redacted] / MWh based upon 20 years of generation including ancillary services. In addition, the underlying market prices would increase under such a scenario since regional hydro would also be reduced. Consequently, $[redacted] / MWh is an extremely conservative estimate of the difference between the cost of the proposed Agreement under the adverse hydro conditions described above and the market price including ancillary services.

Hydro Question #4. What level of average hydro would push levelized contract prices to a level that is equivalent to PSE's estimate of market value plus ancillary services that is approximately $[redacted] / MWh?

Chelan Power System generation equal to 66.5% of average would increase the cost under the proposed Agreement to $[redacted] ($[redacted] / 0.665). However, 66.5% is lower than the lowest year on record and this situation would, presumably, only occur under conditions where Chelan Power System generation is reduced by some other factor besides natural flow conditions.