EXHIBIT NO. ___(WFD-1T)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: WILLIAM F. DONAHUE

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
WILLIAM F. DONAHUE
ON BEHALF OF PUGET SOUND ENERGY, INC.

FEBRUARY 15, 2006

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF WILLIAM F. DONAHUE

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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

A. My name is William (Bill) F. Donahue. My business address is 10885 N.E. Fourth Street Bellevue, WA 98004. I am the Manager, Gas Resource Planning and Analysis for Puget Sound Energy, Inc. ("PSE" or "the Company").

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

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

Q. What are your duties as Manager, Gas Resource Planning and Analysis for PSE?

A. My responsibilities include: (i) performing long-term gas resource planning for both the gas and electric portfolios, including preparation of the gas portions of the Company's Least Cost Plan; (ii) providing analytical support for long-term gas resource acquisitions; (iii) maintaining the Company's relationship with pipeline owners and operators; (iv) negotiating pipeline capacity acquisitions; and (v) representing the Company before the Federal Energy Regulatory Commission ("FERC") and Canadian regulatory bodies involving gas pipeline and storage rates and tariffs.

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

A. My testimony provides an overview of the Company's Gas Supply Portfolio and describes the Company's acquisition at the end of 2005 of pipeline capacity formerly held by Duke Energy Trading and Marketing ("DETM") on the Westcoast Energy Pipeline, a part of Duke Energy Gas Transmission, ("Westcoast Pipeline") and Northwest Pipeline. I explain why the Company needs this capacity and why the acquisitions will benefit the Company's gas customers.

My testimony also describes how the Company plans for and acquires the gas transportation capacity that it will need to serve its natural gas customers, particularly during extremely cold weather events. I discuss this topic in support of the Company's gas cost of service analysis in this case and I provide a recommendation as to the allocation of certain pipeline capacity costs.

II. AN OVERVIEW OF PSE'S GAS SUPPLY PORTFOLIO

Q. Where does PSE acquire the natural gas used to serve its gas customers?

A. As discussed in more detail in PSE's 2005 Least Cost Plan,[1] PSE purchases gas supplies under firm contracts from producers, aggregators and marketers in three distinct supply basins in the western United States and Canada: the U.S. Rocky Mountains, Alberta and British Columbia. PSE typically acquires gas at one or more of the following major trading hubs: "Station 2" in northern British Columbia; "Sumas" on the British Columbia/Washington border; "AECO", which is a nominal point on the Nova Gas Transmission System in Alberta; and "Opal" at the outlet of a major gas processing facility in southwestern Wyoming. PSE also occasionally acquires gas at "Ignacio", the outlet of a gas processing plant in the San Juan Basin area of northwestern New Mexico, and "Stanfield", an interconnect with another pipeline in eastern Oregon. In addition, PSE acquires gas at numerous, smaller pipeline interconnects in the U.S. "Rockies", along the Northwest Pipeline route in Utah, Colorado and Wyoming. Most of these trading hubs are shown on the map provided later in my testimony.

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[1] *See* Exhibit No. ___(EMM-6) at 12-14.

Q. How does the gas get to PSE's gas customers?

A. PSE contracts for pipeline capacity on Northwest Pipeline to transport essentially all of the gas that is delivered to PSE's customers. Northwest Pipeline is the only pipeline system that directly connects to PSE's distribution system. The points at which the Northwest Pipeline interconnects with PSE's system (approximately 30) are referred to as "citygates." The Northwest Pipeline system brings gas from interconnects with "upstream pipelines"—the Westcoast Pipeline at Sumas and the Gas Transmission Northwest pipeline at Spokane and at Stanfield -- as well as from the various supply areas in the U.S. Rockies. Thus, PSE also contracts for capacity on "upstream" pipelines to bring gas to the Northwest system for delivery to PSE's citygates or to PSE's storage projects (for ultimate delivery at some point to the PSE citygates).

Upstream pipelines include: Westcoast Pipeline, which transports Station 2 gas to Sumas (often referred to as "T-South Capacity"), Nova Gas Transmission, Alberta Natural Gas and Gas Transmission Northwest (the latter three all owned by TransCanada Pipelines), which bring gas from Alberta to Spokane. These pipelines are also shown on the map provided later in my testimony.

Q. What gas storage projects does PSE utilize?

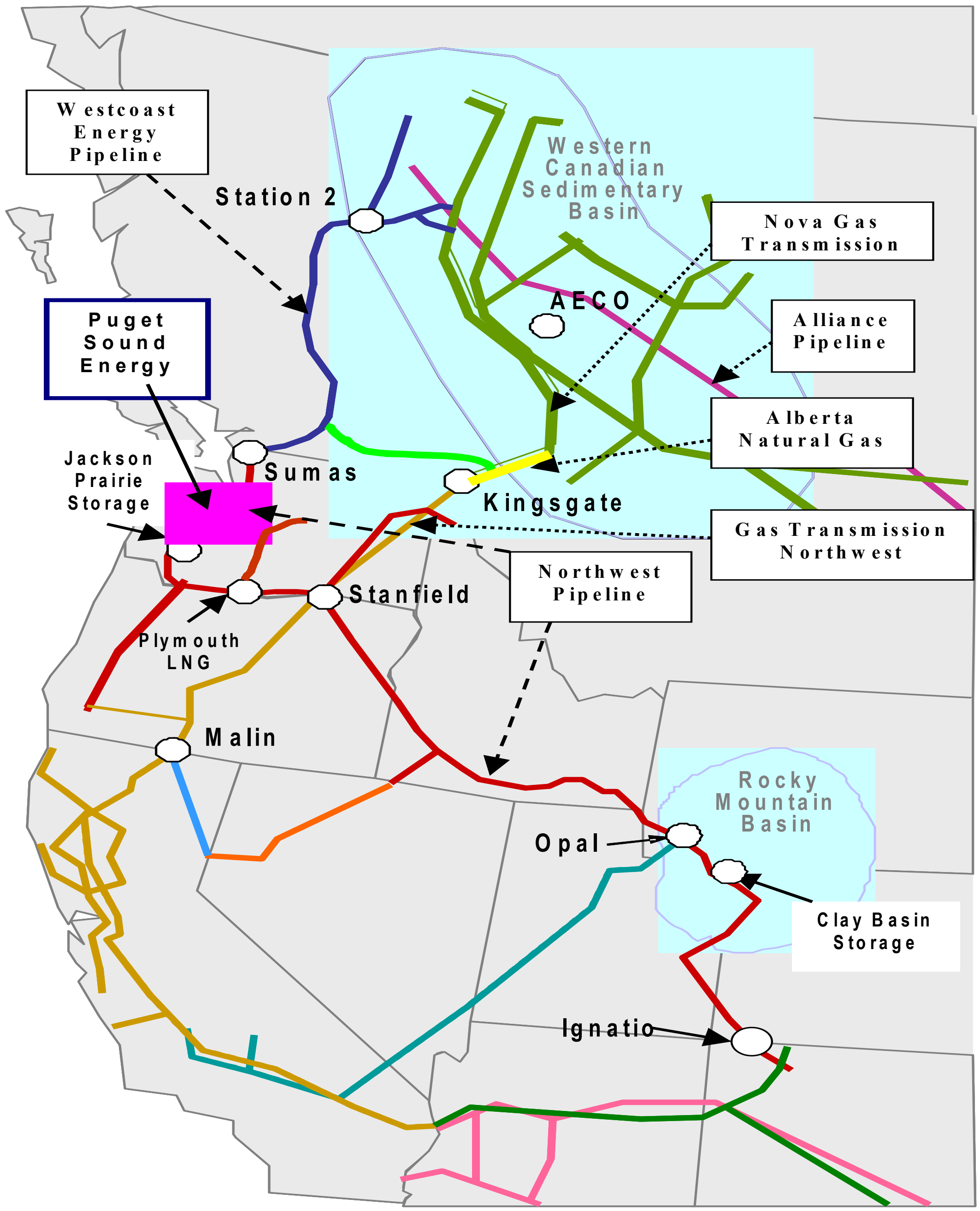
A. PSE owns one-third of the Jackson Prairie Storage Project in Lewis County, Washington, and operates it on behalf of the other owners: Northwest Pipeline and Avista Corporation. In addition to using all of its one-third interest, PSE contracts for use of a portion of Northwest Pipeline's one-third interest in Jackson Prairie. PSE also contracts with Questar Pipeline for storage at the Clay Basin underground storage facility in northeastern Utah. Lastly, PSE contracts for liquefied natural gas storage service from Northwest Pipeline at its Plymouth, Washington liquified natural gas storage facility.

Q. Are these pipeline and storage services and contracts subject to regulation?

A. Yes. The rates, tariffs and service for pipelines and storage operators are subject to regulation as follows: (1) the National Energy Board of Canada regulates Westcoast Pipeline and Alberta Natural Gas; (2) the Alberta Energy and Utility Board regulates Nova Gas Transmission; and (3) FERC regulates Gas Transmission Northwest, Questar Pipeline, and Northwest Pipeline. FERC also regulates PSE as operator of the Jackson Prairie storage facility.

Q. Would you please provide an illustration of the location of the facilities described above?

A. The following map, which is also provided as Exhibit No. ___(WFD-3), shows the regional supply basins, pipeline routes and storage facilities.


Westcoast Energy Pipeline
Station 2
Western Canadian Sedimentary Basin
Nova Gas Transmission
AECO
Alliance Pipeline
Puget Sound Energy
Alberta Natural Gas
Sumas
Kingsgate
Jackson Prairie Storage
Gas Transmission Northwest
Northwest Pipeline
Stanfield
Plymouth LNG
Malin
Rocky Mountain Basin
Opal
Clay Basin Storage
Ignatio

III. PSE ACQUIRED THE CAPACITY OFFERED BY DUKE ENERGY TRADING AND MARKETING AS A LEAST-COST MEANS OF MEETING THE NEEDS OF ITS CORE GAS CUSTOMERS

A. Summary of the Transactions

Q. Please describe the background that gave rise to the capacity transactions with Duke Energy Trading and Marketing.

A. DETM held a substantial pipeline capacity and gas supply position in the Pacific Northwest region, including pipeline capacity on both the Westcoast and Northwest Pipelines. In 2004, DETM sold and transferred the majority of its transportation capacity position and gas supply position to an unaffiliated marketer. DETM retained only selected pipeline capacity in the Pacific Northwest and intended to develop and maintain a smaller marketing presence. In the fall of 2005, however, DETM's parent announced that it would discontinue entire operations of DETM and liquidate its pipeline capacity holdings.

DETM approached PSE with a proposal for PSE to take permanent release of the Northwest Pipeline capacity in exchange for a one-time payment.

Q. How did PSE respond to DETM's proposal?

A. PSE advised DETM that, consistent with PSE's 2005 Least Cost Plan, it did not anticipate a need for the Northwest Pipeline capacity until 2010 or beyond. PSE further advised that it was actually seeking to acquire Westcoast Pipeline capacity of approximately the quantity held by DETM. See Exhibit No. ___(WFD-4).

Q. What happened next?

A. After further dialogue with PSE, DETM proposed a package deal whereby PSE would take permanent release, effective November 1, 2005, of both Westcoast Pipeline capacity and Northwest Pipeline capacity in exchange for a one-time payment to PSE. After negotiations, DETM and PSE agreed to separate payments of $42 million for the Northwest Pipeline capacity and $13 million for the Westcoast Pipeline capacity, if both capacities were acquired effective January 1, 2006.

After the final execution of documents, PSE completed the transactions in the last two weeks of 2005, receiving title to the capacities effective January 1, 2006 as well as the agreed payments from DETM.

B. <u>The Westcoast Capacity Met PSE's Immediate Need for Additional T-South Capacity from Station 2 in Northern British Columbia</u>

Q. Please describe the Westcoast capacity.

A. The Westcoast Pipeline "T-South" capacity provides firm capacity to transfer approximately 56,000 Dth/day from the northern British Columbia gas supply hub, known as "Station 2", to the Sumas Export interconnect with Northwest Pipeline. The contract has a remaining primary term through October 31, 2017.

The contract volume declines to approximately 45,000 Dth/day on November 1, 2012, and to 26,000 Dth/day on November 1, 2014. PSE has renewal rights under Westcoast's tariff, which allow for extension of the term at PSE's request. This provision would allow PSE to maintain the full 56,000 Dth/d initial capacity for the entire term of the agreement, if the election is made when capacity is not otherwise committed.

Q. Why did PSE acquire the Westcoast capacity?

A. PSE has an identified strategic need for this capacity from now (the winter of 2005-06) for the foreseeable future, as generally described in PSE's 2005 Least Cost Plan ("LCP").[2] The northern British Columbia "Station 2" supply hub is growing in volume and liquidity at the same time as the historic Sumas supply point is declining. Accessing gas supply at Station 2 (and maintaining "T-South" pipeline capacity to move it to Sumas) can be more advantageous than relying on acquiring gas at Sumas for at least two reasons.

First, the depth and breadth of the gas supply market at Sumas has declined significantly in the past few years. There is evidence that gas producers and gas marketers have substantially abandoned the practice of holding firm long-term pipeline capacity from Station 2 to Sumas, presumably to maximize their options to sell gas into other markets from the pipeline hub in northern British Columbia.

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[2] *See* Exhibit No. ___(WFD-8) at 3-5 and Exhibit No. ___(WFD-9) at 41.

Firm T-South capacity formerly held by producer/marketers has been largely turned-back to Westcoast as contracts have come up for renewal. As a result, there is very little capacity held by producers or marketers on the Westcoast Pipeline to move gas to interruptible or short-term markets at Sumas. Nearly all of the contracted T-South capacity is dedicated to a producers' and marketers' existing firm supply sales commitments at Sumas (which will be turned back to the pipeline when the existing contract terminates) or held by local distribution companies ("LDCs") such as PSE or others to provide supplies from Station 2 for their firm customers. Thus, it is becoming ever more difficult to find reliable suppliers who will commit to sell firm gas supply at Sumas. This condition would likely lead to substantial price spikes (representing a scarcity premium) for those few quantities of uncommitted gas at Sumas when high demand occurs.

Second, gas prices at Station 2 (plus the cost of transporting to Sumas) is likely to be lower cost than acquiring marginal gas supply at Sumas. Short-term firm and interruptible T-South capacity is priced at a minimum of 133% of the long-term firm rate. Thus, at least in periods of high demand, the market clearing price of incremental gas supply -- the volumes that establish Sumas index price -- will generally need to be high enough to cover the Station 2 gas price plus 133% of the T-South capacity rate. This circumstance will result in savings of at least 10 cents per decatherm. Often, the gas price differential between Station 2 and Sumas is substantially higher than just 33% of the tariffed transportation rate.

Q What are the implications of these market conditions?

A. In order to assure continued reliable access to a ready supply of gas to serve its firm gas customers, PSE must maintain a substantial volume of pipeline capacity from Station 2. Because PSE holds and relies on 205,000 Dth/day of Northwest Pipeline capacity originating from Sumas to PSE's system to serve core gas customers, a reliable upstream source of gas is also required. PSE holds firm gas supply contracts totaling 50,000 Dth/day for delivery to PSE at Sumas. Additional supply to fill the 205,000 Dth/day need must be acquired in the short-term market at Sumas or by purchases at Station 2 with transportation on the Westcoast Pipeline system to Sumas. PSE has concluded it is reasonable to assume that it will continue to be able to acquire renewals of existing firm supplies at Sumas or access short-term firm supplies at Sumas for approximately one-half of its 205,000 Dth/day need.

For these reasons, PSE concluded that it was appropriate to supplement its existing portfolio of approximately 41,000 Dth/day of Westcoast T-South capacity with up to an additional 60,000 Dth /day. This resource acquisition was authorized at the September 15, 2005 Energy Management Committee meeting. *See* Exhibit No. ___(WFD-4). PSE's acquisition of the approximately 56,000 Dth/day Westcoast capacity from DETM met this need.

Q. Has PSE begun using the new Westcoast T-South capacity?

A. Yes, in early January 2006, when PSE could begin nominating the new T-South capacity, the Company began moving incremental Station 2 gas to Sumas for use in its supply operations. At that time, Sumas gas was trading in excess of 60 cents more than Station 2. As a result, the Company realized savings for its core gas customers of more than 10 cents per decatherm over Sumas priced gas supply, after taking into account the full cost of T-South capacity including reimbursement of fuel to the pipeline.

C. <u>The Northwest Pipeline Capacity and Related Up Front Payment from DETM were a Least Cost Solution for Meeting PSE's Need for Additional Capacity Commencing in 2010/2011.</u>

Q. Please describe the Northwest Pipeline capacity that was acquired from DETM.

A. The Northwest Pipeline capacity provides firm pipeline capacity to transport 55,000 Dth/day from the Sumas gas-trading hub (or from the more liquid hub at Station 2 – when used with Westcoast T-South capacity) to nearly all of the gate stations serving PSE's gas distribution system. This capacity may be used alone to move incremental supplies from Sumas (when gas is available) to PSE's system— use of matching Westcoast capacity is not required.

The contract has a standard bilateral evergreen provision, whereby the contract continues from year-to-year until terminated by either party with one-year notice.

Under FERC standards, the Right of First Refusal (or ROFR) rights also apply.

Q. Did the Company analyze the need for the Northwest Pipeline capacity before entering into that contract?

A. Yes. In analyses performed in conjunction with PSE's 2005 Least Cost Plan, PSE identified the subject Northwest Pipeline Evergreen Expansion[3] capacity as the least cost resource after (i) certain energy efficiency programs commencing in 2006; (ii) a 100,000 Dth/day deliverability expansion of Jackson Prairie Storage in 2008; and (iii) 50,000 Dth/day of new Northwest Pipeline capacity assumed to be built in connection with the availability of imported liquefied natural gas supply in the area "south of PSE's service area" (presumably near Portland) in 2010. The 2005 LCP analyses concluded that the Northwest Pipeline capacity held by DETM (and another party) would be optimally acquired gradually in 2011, 2012 and 2013. All analyses assumed the subject capacity would be available at the full applicable Northwest Pipeline tariff rate.

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[3] The capacity was originally built as part of Northwest Pipeline's Evergreen Expansion Project in 2003. The capacity is priced at an incremental 15 year levelized rate. The capacity formerly held by DETM has a primary receipt point at the Sumas Interconnect with Westcoast Pipeline and a primary delivery point at the Grays Harbor meter station near Olympia, Washington.

Q. Did the Company update its analysis subsequent to the filing of its 2005 LCP?

A. Yes. PSE's continued monitoring of the liquefied natural gas market and dialogue with Northwest Pipeline subsequently suggested that it is highly unlikely that imported liquefied natural gas near Portland would be available by 2010, and that new incremental pipeline capacity from the south to PSE's service territory would be more expensive than previously modeled. In addition, PSE updated its assumptions to reflect the impact of energy efficiency programs as incorporated in PSE's most recent gas program filings.

Subsequent modeling of resource need utilizing the lower energy efficiency volumes and reflecting the unavailability of the imported liquefied natural gas-related pipeline capacity, indicated the subject Northwest Pipeline capacity would be required by 2010-11. See Exhibit No. ___(WFD-5).

Q. What type of analyses did the Company perform in association with this acquisition?

A. PSE applied two analytical methods to determine whether the DETM Evergreen Expansion capacity, at the expected rates for such service, would be a least cost addition to the Company's gas portfolio.

First, the long-term cost impact of adding DETM's Evergreen Expansion capacity was estimated, without consideration of the value of the $42 Million up-front payment from DETM. This approach (referred to herein as "Minimum Payment Analysis") identifies a benchmark minimum value (for the up-front payment) required to reasonably ensure the capacity will reduce gas costs in the long term.

Second, an "Optimization Analysis" was performed on a specific amortization schedule (as proposed in the Company's Accounting Petition dated January 5, 2006, in Docket No. UG-060019) to let the Company's linear programming gas resource model (known as the "Sendout" model) determine if that specific arrangement would be selected as part of the long-term optimal portfolio.

Q. Was uncertainty analysis used, or did the Company rely on a single static set of assumptions?

A Two forms of uncertainty analysis were used in both the Minimum Payment Analysis and the Optimization Analysis methods. Scenario analysis was used to examine the impact of different long-term design day load forecasts and Monte Carlo analysis was used to examine the sensitivity of each analysis to a range of commodity prices and temperature driven load variations.

Q. What were the results of the Minimum Payment Analysis?

A. The net present value of the amortization of the $42 million up-front payment that PSE proposed in its Accounting Petition is more than the minimum payment required to reduce gas costs in the scenario using the Company's most recent load forecast, and more than the minimum payment required to reduce gas costs using the base 2005 LCP load forecast scenario.

Monte Carlo analysis was used to examine the sensitivity of the minimum payment required from DETM to the specific price and weather-related load assumptions used in the static analysis noted above. The analysis examined how 100 different commodity price and weather scenarios would affect the minimum payment value. This analysis allows an assessment of the degree of certainty with which the up-front payment is expected to at least cover the minimum amount required. The results indicated that PSE's proposed amortization method would be sufficient – at the 95th percentile -- to cover the additional cost of including DETM Evergreen Expansion capacity in the portfolio.

Q. Please describe the results of the Optimization Analysis.

A. In contrast to the Minimum Payment Analysis outlined above, the Optimization Analysis used the Sendout model to determine if the DETM Evergreen Expansion capacity at expected tariff rates, offset by the effect of the specific amortization schedule, would be selected as part of the least cost long-term portfolio from a variety of resource alternatives. The analysis assumed the 2008 Jackson Prairie Deliverability Expansion would be completed and PSE would also have acquired a related storage redelivery service. Alternative resources included other surplus Evergreen Expansion capacity (assumed to be available from a third party at a 40% on-going-- not pre-paid --discount) and future Northwest Pipeline capacity expansions. As with the prior analysis, uncertainty was examined using both multiple load scenarios and Monte Carlo analysis.

Scenarios examined were the same as the scenarios for the Minimum Payment Analysis. In both the 2006 load forecast scenario and the 2005 LCP load forecast scenario, the Sendout model identified all of the DETM capacity (with an amortization of the $42 Million pre-payment similar to that proposed in the Company's Accounting Petition) as a least-cost addition to the portfolio.

D. <u>Conclusion Regarding the DETM Capacity Acquisitions</u>

Q. What are the anticipated benefits to PSE's gas customers of the natural gas pipeline capacity contracts acquired from DETM?

A. The Westcoast Pipeline capacity will provide PSE with access to Station 2 supplies in a market environment that is anticipated to result in lower gas supply costs at that market hub than at the Sumas hub. Moreover, PSE believes that it obtained this Westcoast capacity at a cost that is significantly lower than full-posted tariff rates and capacity available from other third parties.

The Northwest Pipeline capacity is a least cost long-term resource alternative for PSE's gas customers. Moreover, the accounting treatment proposed by the Company and approved by the Commission in Docket No. UG-060019 on January 25, 2006, will result in there being no cost to PSE customers until that capacity is needed in early 2011.

IV. PIPELINE CAPACITY COST CAUSATION

Q. What is the purpose of this section of your testimony?

A. This section of my testimony describes the manner in which the Company plans for and acquires the gas transportation capacity that will be needed to serve its natural gas customers. I discuss this topic in support of the Company's proposal in this case to determine the cost of serving gas customers by reference to design day demand rather than by reference to historic or average actual peak day demand, as described in the testimonies of Mr. Ron Amen, Exhibit No. ___(RJA-1T) and Ms. Janet Phelps, Exhibit No. ___(JKP-1T). Ultimately, I provide a recommendation as to the allocation of pipeline capacity and storage costs for use in PSE's cost of service analysis in this case.

Q. Please describe what drives PSE's decisions whether to acquire more pipeline capacity.

A. Most of PSE's natural gas customers are "firm" customers as opposed to "interruptible" customers. Interruptible customers take service under tariff schedules that permit PSE to temporarily stop their gas supply at times in order to ensure service to PSE's firm customers. By contrast, firm customers expect to receive gas at all times, including (and particularly) during extremely cold weather. Demand for natural gas from PSE's firm customers is at its highest during cold weather. However, the cold weather increases the demand of other pipeline customers, thus reducing the availability of contracted but unused pipeline capacity.

Given PSE's obligation to serve its firm customers, it is the expected customer demand, and in particular the shape of that demand, that drives PSE to acquire pipeline capacity. As more fully described in the Company's 2005 LCP, PSE has determined and adopted an economically reasonable design-day demand standard.[4] In ensuring its gas needs, PSE seeks the least cost mix of available resources that can meet that design-day standard. Often, due to lack of additional cost-effective energy efficiency measures, storage or other peaking resources, the only available incremental resource to ensure PSE's ability to meet its design day standard is year-round pipeline capacity.

Q. What is "year-round pipeline capacity"?

A. PSE has only two types of pipeline capacity from which to chose to deliver gas directly to its distribution system. The first, year-round pipeline capacity, is often referred to by its Northwest Pipeline tariff: "TF-1". The other, known as "TF-2", is a grandfathered winter-only firm transportation service for redelivery of gas held in market-area storage at Jackson Prairie Storage Project, Plymouth Liquified Natural Gas Project and Mist Storage Project. Because no additional

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[4] *See* Exhibit No. ___(WFD-9) at 3 and Exhibit No. ___(WFD-10).

TF-2 capacity is available from Northwest Pipeline, the only real choice PSE has when it needs additional capacity is year-round TF-1 pipeline capacity.

Q. How does PSE determine that it needs additional pipeline capacity?

A. In simple terms, the process for determining the need for incremental pipeline capacity can be summarized in the six-step process described below. The six steps reflect a logical progression in identifying why capacity is needed, and thus give guidance as to how to allocate the costs related thereto.

Q. Please identify the steps and how they can guide cost allocation.

A. **<u>Step 1:</u>** First, one must consider the summer demand or sales volume. This must be served by flowing gas supply using year-round pipeline capacity because, other than for load balancing, storage and peaking resources are not available in the summer. PSE's normalized average daily sales volume in the summer months during the 12 months ended September 2005 was approximately 142,000 Dth/day. Thus average summer sales volumes require pipeline capacity of 142,000 Dth/day. Since this capacity is only available on a year-round basis, and will be used to serve winter sales volumes as well (Step 2), it is reasonable to allocate the cost of this capacity to Annual Sales Volumes.

<u>Step 2:</u> Second, in order to have sufficient volumes in storage to serve the winter sales volumes, storage injections must be made using flowing gas and year-round pipeline capacity. Average summer injection requirements are 76,000 Dth/day if

PSE storage accounts at Jackson Prairie and Clay Basin are cycled 75% annually. PSE could schedule its injection requirements around its customer requirements and operate all summer long with 218,000 Dth/day of pipeline capacity. Because this capacity is needed specifically to fill storage, which is in turn used to serve winter sales volumes, it is reasonable to allocate the costs of this capacity to Winter Sales Volumes. Of course, this capacity is also available to flow additional gas to serve winter sales volumes after the summer injection period (Step 3).

Step 3: Third, before determining the need for additional pipeline capacity to serve winter demand, PSE considers the average availability of storage withdrawals from Jackson Prairie that use TF-2 capacity and thus do not require the use of TF-1 capacity. (Note that withdrawals from Clay Basin storage cannot be delivered to PSE using TF-2 and thus must use some of the TF-1 capacity already acquired in Steps 1 or 2.) Average Daily winter withdrawals from Jackson Prairie storage average approximately 41,000 Dth/day and do not require TF-1 pipeline capacity. The TF-2 capacity utilized by Jackson Prairie withdrawals would reasonably be allocated partially to Winter Sales Volumes, Design Peak Volumes and of course, System Load Balancing.

Step 4: Fourth, Winter average daily sales volumes are 358,000 Dth/day. These requirements are met with the capacity acquired in Steps 1, 2 and 3, thus leaving an average winter sales demand of 99,000 Dth/day (358,000 minus 142,000 minus

76,000 minus 41,000) to be fulfilled with additional TF-1 capacity. It is reasonable to allocate the costs of this capacity to Winter Sales Volumes.

Step 5: Fifth, PSE considers its Design Peak Sales Requirement, and the deliverability of all of its storage and peaking services that have not already been considered in use on the average winter day. PSE's estimated design peak requirement for the 12 months ended September 2005 was approximately 901,000 Dth/day. PSE's peaking and storage resources provide, at maximum deliverability, a total of 474,500 Dth/day (343,000 from Jackson Prairie; 70,500 from Plymouth LNG; 3,000 from Gig Harbor LNG; 48,000 from an Oil for Gas diversion contract at a generating plant and 10,000 from Propane Air). However, PSE has already relied on 40,600 Dth/day from Jackson Prairie on an average winter day in Step 3, thus incremental storage and peaking provide a resource of 433,900 Dth/day (474,500 minus 40,600). It is reasonable that the costs of the various resources that provide this incremental deliverability should be allocated based on their use to serve the design peak requirements of the system.

Step 6: Lastly, the design peak demand is not yet met, and no additional energy efficiency, storage or peaking resources are available in a cost effective manner PSE thus must acquire additional year-round (TF-1) pipeline capacity of 147,500 Dth/day (901,000 minus 142,400 minus 76,000 minus 99,100 minus 474,500 plus an approximately 4% reserve of 38,500) to make up the shortfall. Because this last increment of capacity is required only to serve the design peak day requirements of the customer demand, it is reasonable to allocate the cost of this capacity based on the contribution of various customer classes to design peak day demand.

Exhibit No. ___(WFD-6) illustrates the six steps described above in graphical format.

Q. What is your overall recommendation as to the allocation of TF-1 pipeline capacity and storage and redelivery capacity (TF-2) costs?

A. As summarized in the table on Exhibit No. ___(WFD-7), showing the six step process, I recommend that TF-1 pipeline costs should be allocated 30.6% to Annual Sales Volumes, 37.7% to Winter Sales Volumes and 31.7% to Design Peak Volumes. I recommend that the 78% of Jackson Prairie and its related TF-2 capacity that is not allocated to system balancing be allocated as follows: 9.2% to Winter Sales and 68.8% to Design Peak Day. I recommend that all of the costs of Clay Basin Storage be allocated to Winter Sales.

V. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

[BA060450018]